Show Me the Numbers

A Framework for Balanced Distributed Solar Policies

Prepared for Consumers Union

November 10, 2016

AUTHORS

Tim Woolf
Melissa Whited
Patrick Knight
Tommy Vitolo, PhD
Kenji Takahashi

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

LIST OF TABLES AND FIGURES

ACKNOWLEDGEMENTS

This work was funded through the support of the Energy Foundation.

The authors wish to acknowledge the many helpful comments and suggestions received from our reviewers: Shannon Baker-Branstetter, Consumers Union; Sara Baldwin-Auck, Interstate Renewable Energy Council; Galen Barbose, Lawrence Berkeley National Laboratory; Mark Detsky, Energy Outreach Colorado; David Farnsworth, Regulatory Assistance Project; Rick Gilliam, Vote Solar; Richard Sedano, Regulatory Assistance Project; Curtis Seymour, Energy Foundation; Gabrielle Stebbins, Energy Futures Group.

However, the views and opinions expressed in this report are those of the authors and do not necessarily reflect the positions of the reviewers. Further, any omissions or errors are the authors'.

Executive Summary

Jurisdictions across the country are grappling with the challenges and opportunities associated with increasing adoption of distributed solar resources. While distributed solar can provide many benefits—such as increased customer choice, decreased emissions, and decreased utility system costs—in some circumstances it may result in increased bills for non-solar customers. In setting distributed solar policies, utility regulators and state policymakers should seek to strike a balance between ensuring that cost-effective clean energy resources continue to be developed, and avoiding unreasonable rate and bill impacts for non-solar customers.

To address this challenge, many jurisdictions are considering modifying distributed solar policies or implementing fundamental changes to rate design, such as increased fixed charges, residential demand charges, minimum bills, and time-varying rates. While it is prudent to periodically review and modify rate designs and other policies to ensure that they continue to serve the public interest, decision-makers frequently lack the full suite of information needed to evaluate distributed solar policies in a comprehensive manner. As this report demonstrates, it is critical to have accurate inputs, especially for "avoided costs" in order to identify whether a policy will increase or decrease rates for non-solar customers.

Regulators must strike a balance between ensuring that cost-effective resources continue to be developed, and avoiding unreasonable impacts on non-solar customers.

This report provides a framework for helping decision-makers analyze distributed solar policy options comprehensively and concretely. This framework is grounded in addressing the three key questions that regulators should ask regarding any potential distributed solar policy:

1. How will the policy affect the development of distributed solar?
2. How cost-effective are distributed solar resources?
3. To what extent does the policy mitigate or exacerbate any cost-shifting to non-solar customers?

Answering these questions will enable decision-makers to determine which policy options best balance the protection of customers with the promotion of cost-effective distributed solar resources. This report describes the analyses that can be used to answer these questions.

Analysis 1: Development of Distributed Solar

Customer payback periods provide a useful metric to indicate the extent to which different solar policies will affect the growth, or lack of growth, of distributed solar resources. Policies that lead to very short customer payback periods will likely produce rapid growth in these resources, while policies that lead to very long customer payback periods will likely result in little growth. Market penetration curves can be used to estimate eventual customer adoption levels from customer payback periods. Changing a customer's payback period will impact how economically attractive distributed solar is, and thereby affect how many customers ultimately adopt the technology.

Analysis 2: Cost-Effectiveness of Distributed Solar

Distributed solar can offer the electric utility system and society a host of benefits, ranging from avoided energy and capacity costs to reduced impacts on the environment and greater customer choice. At the same time, distributed solar may impose administration and integration costs on the utility system. Many recent studies have assessed whether the benefits of distributed solar outweigh the costs. These studies are most informative when they use clearly defined, consistent methodologies for assessing costs and benefits.

The most relevant cost-effectiveness tests for evaluating distributed solar are the Utility Cost Test, the Total Resource Cost Test, and the Societal Cost Test, which are based on the cost-effectiveness analyses long applied to energy efficiency resources.

- The Utility Cost Test indicates the extent to which distributed solar will reduce total electricity costs to all customers by affecting utility revenue requirements.
- The Societal Cost Test takes a broader look and indicates the extent to which distributed solar will help meet a state's energy policy goals such as environmental protection and job creation, as well as reducing customer electricity costs.
- The Total Resource Cost Test, in theory, indicates the extent to which distributed solar will reduce utility system costs net of the host customer's costs. This test should be used with caution, as it has some structural constraints that limit its usefulness.

Analysis 3: Cost-Shifting from Distributed Solar

Cost-shifting from distributed solar customers to non-solar customers occurs in the form of rate impacts. Distributed solar can cause rates to increase or decrease due to changes in electricity sales levels, costs, or both. A comprehensive rate impact analysis is the best way to analyze the potential for cost-shifting from distributed solar.

When evaluating cost-shifting, it is important to analyze both long-term and short-term rate impacts to understand the full picture. Often, the benefits of distributed solar are not realized for several years, while a decrease in electricity sales occurs immediately, resulting in short-term rate increases followed by long-term rate decreases. Thus a short-term rate impact analysis will not fully capture the impacts of distributed solar.

Because distributed solar resources can create both upward and downward pressure on rates, the combined effect could result in in either a net increase or decrease in average long-term rates.

In their most simplified form, electricity rates are set by dividing the utility class's revenue requirement by its electricity sales. Thus rate impacts are primarily caused by two factors:

1. Changes in costs: Holding all else constant, if a utility's revenue requirement decreases, then rates will decrease. Conversely, if a utility's revenue requirement increases, rates will increase. Distributed solar can avoid many utility costs, which can reduce utility

revenue requirements. Distributed solar can also impose costs on the utility system (such as interconnection costs and distribution system upgrades).

2. Changes in electricity sales: If a utility must recover its revenues over fewer sales, rates will increase. This is commonly referred to as recovering "lost revenues," and is an artifact of the decrease in sales, not any change in costs. Lost revenues should be accounted for in the rate impact analysis, but not in the cost-effectiveness analysis.

Whether distributed solar increases or decreases rates will depend on the magnitude and direction of each of these factors.[1] In very general terms, if the credits provided to solar customers exceed the average long-term avoided costs, then average long-term rates will increase, and vice versa.

Summary of Analytical Framework for Assessing Distributed Solar Policies

The results of the three analyses described above can be pulled together into a single framework to evaluate different distributed solar resource policies in an open, data-driven regulatory process. The framework proposed here includes several steps that policymakers, regulators, or other stakeholders can take to assess the implications of different distributed solar policies. These steps are summarized in Table ES.1.

Table ES.1 Steps Required to Assess Distributed Solar Policies

Step 1	Articulate state policy goals regarding distributed solar resources.
Step 2	Articulate all the existing regulatory policies related to distributed solar resources.
Step 3	Identify all of the new distributed solar policies that warrant evaluation.
Step 4	Estimate the customer adoption rates under current solar policies, and new solar policies.
Step 5	Estimate the cost-effectiveness of distributed solar under current policies and new policies.
Step 6	Estimate the extent of cost-shifting under current solar policies, and new solar policies.
Step 7	Use the information provided in the previous steps to assess the various policy options.

To facilitate understanding and decision-making, it is useful to summarize the results of the three analyses in a single table. Table ES.2 provides an example of how the results could be summarized for reporting and decision-making purposes.

The primary recommendation from this report is that regulators should require utility-specific analyses of: (1) distributed solar development, (2) cost-effectiveness, and (3) cost-shifting impacts of relevant distributed solar policies. This will allow for a concrete, comprehensive, balanced, and robust discussion of the implications of the distributed solar policies.

[1] Whether rates actually increase or decrease is also dependent upon a host of other factors not related to distributed solar.

Table ES.2 Summary of Hypothetical Results

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	Total Resource Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*$ Million*	*$ Million*	*$ Million*	*$/mo*	*%*
Policy 1							
Policy 2							
Policy 3							

Using the results of the analyses presented above, policymakers, regulators, or other stakeholders can review the projected impacts of various policy options to determine what course of action is in the public interest. Appropriate consideration of all relevant impacts will help decision-makers to avoid implementing policies that have unintended consequences or that fail to achieve policy goals. The results of such analyses can also help to determine the point at which certain distributed solar policies should be reevaluated and modified over time.

Given that each jurisdiction has its own policy goals and unique context, the ultimate policy decision reached may be different in each jurisdiction, even when based on the same analytical results. Nonetheless, the framework articulated above will provide decision-makers with the ability to balance protection of customers with overarching policy objectives in a transparent, data-driven process.

1. INTRODUCTION AND BACKGROUND

Distributed solar[2] can pose a challenge for policymakers, regulators, and consumer advocates as it can reduce system costs over the long-run, but in some cases may also result in increased bills for non-solar customers. This report is intended to provide a guide for decision-makers and other stakeholders who seek to strike a balance between ensuring that cost-effective resources continue to be developed, while avoiding unreasonable rate and bill impacts on non-solar customers.

Nearly every state in the nation has adopted net metering as a compensation mechanism for distributed solar customers. However, jurisdictions across the country are beginning to reevaluate their distributed solar policies. For example, in the first quarter of 2016, 22 states considered or enacted changes to net metering policies (NCCETC 2016). While simple to administer (and simple to understand), concerns have been raised that net metering may lead to unacceptable rate impacts on non-solar customers.

It is prudent to periodically review and modify distributed solar policies to ensure that they continue to serve the public interest. To date, however, many jurisdictions have developed or modified their policies in a piecemeal fashion, rather than based on a quantitative analysis of the various impacts that distributed solar can have on the utility system and other customers. Without appropriate data-driven consideration of all relevant impacts based, decision-makers risk implementing policies that have unintended consequences or that fail to achieve policy goals.

Regulators should strike a balance between ensuring that cost-effective resources continue to be developed, while avoiding unreasonable impacts on non-solar customers.

This report provides a framework for helping decision-makers analyze distributed solar policy options more comprehensively by evaluating three critical indicators:

- The likely customer adoption of distributed solar
- The cost-effectiveness of distributed solar
- The magnitude of cost-shifting to non-solar customers

Once the results of these analyses are available, decision-makers can evaluate their policy options to determine what course of action will be in the best interest of customers as a whole by balancing the protection of customers with development of distributed solar resources.[3]

Appendix A provides sample discovery questions designed to assist stakeholders obtain the key pieces of information required for conducting the analyses recommended in this report. It is critical to have accurate inputs, especially for avoided costs, to accurately estimate the impacts of distributed solar policies. The answers to these questions will differ across jurisdictions, and thus the framework should be applied using the best available information that is relevant to each jurisdiction.

[2] We use the term "distributed solar" to refer to small solar photovoltaic (PV) systems that are located on the distribution system. These systems generally take the form of rooftop PV operating behind the meter, but may also include installations not sited at the point of use, such as community solar.

[3] Regulators are tasked with implementing laws that have been adopted by the state legislature or executive branch. In some cases utility regulators have a wide range of policy options; in other cases the options are dictated by the state government.

2. Distributed Solar Policy Options

A comprehensive analysis of distributed solar policy options should begin with an explicit articulation of the jurisdiction's energy policy goals. Such policy goals may include (a) reducing electricity costs, (b) promoting customer control or choice, (c) reducing environmental impacts, and (d) promoting local jobs and economic development. In addition, jurisdictions generally attempt to balance these goals with the goal of avoiding or mitigating unreasonable cost-shifting to non-solar customers. These policy goals should inform the selection of policy options related to distributed solar and the evaluation of their impacts.

Policies that impact distributed solar include, but are not limited to: compensation mechanisms; rate designs that directly affect the credits that solar customers receive; program enrollment level caps; interconnection standards that govern the processes for connecting to the grid; and other policies designed to reform long-term grid planning efforts such that higher penetrations of distributed solar can be more easily accommodated and optimized on the grid. Regulators and policymakers can adjust these policies to encourage balanced growth of distributed solar and to mitigate rate impacts. The table below provides examples of the various types of policy options and supporting activities.[4]

Table 1. Distributed Solar Policy Categories

Policy	Examples
Compensation Mechanisms	Net metering, feed-in-tariff, value-of-solar tariff, renewable energy certificates, rooftop lease payments, performance incentives
Rate Design	Fixed charges, demand charges, time-of-use rates, bypassable versus non-bypassable bill components
Up-Front Incentives and Financing	Investment tax credits, sales tax exemptions, rebates, loans, grants
Interconnection and Permitting	Expedited review, mandated time limits, zoning exemptions, interconnection and permitting fees
Integration and Planning	Hosting capacity analyses, integrated resource planning, distribution system planning
Ownership	Customer up-front purchase, third-party ownership, utility ownership and lease to customer, loans
Education, Training, And Outreach	Information, tools, workshops, online assistance, community outreach

[4] Many residential and small commercial customers choose to lease their system or enter into a power purchase agreement (PPA) with third-party solar developers. Therefore it may be important to understand how various policies affect these developers, rather than only the host customers, when considering policy options.

In this report, we focus primarily on compensation mechanisms and rate design for residential and small commercial solar customers.[5] Often compensation mechanisms and rate design work in tandem, such as under net metering policies where a change in rate design can affect the net metering credit. Compensation mechanisms and rate design are particularly important policies for decision-makers to consider, as they can impact the rate of adoption of distributed solar, the magnitude of any rate impacts on non-solar customers, and the extent to which utilities are able to recover their allowed revenues.

In this report, we focus primarily on compensation mechanisms and rate design for residential and small commercial solar customers.

2.1. Rate Design and Distributed Solar

The Purpose of Rate Design

When considering rate design modifications, it is important to keep in mind the core objectives of electricity rates. In 1961, Professor James Bonbright set forth eight rate design principles, and distilled these principles into the following three objectives:

1. The revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies;
2. The fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service; and
3. The optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received (Bonbright 1961, 292).

The first objective seeks to ensure that utilities are able to recover sufficient revenues; the second objective is focused on fairness of rates; and the third objective addresses efficient resource usage.

These three objectives are still as relevant today as they were in 1961, with one modification. Customers are no longer only consumers; rather, they are increasingly also producers of a range of services, such as energy generation, demand reduction, and even ancillary services. For this reason, the third objective need not be limited to encouraging customers to *consume* electricity efficiently, but also to *produce* electricity (and related services) efficiently. With this modification, Bonbright's third objective also

[5] For simplicity, we assume that rate design and compensation mechanisms will affect the payback period for both third-party developers and host customers who purchase their systems outright in a similar manner.

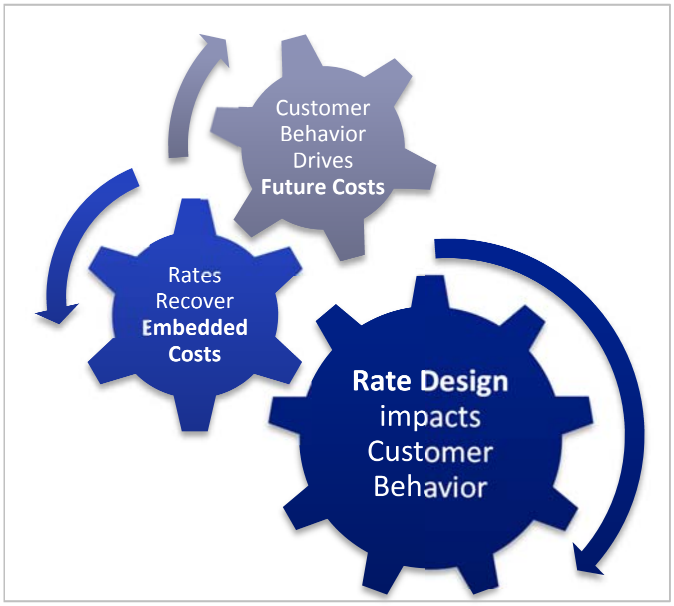
includes the primary objective of resource planning, namely the cost-effective procurement of resources, including distributed solar.[6]

Rate Design as a Balancing Act

Regulators strive to protect the long-run interest of customers by overseeing the provision of reliable, low-cost energy, while also ensuring that rates are fair, just, and reasonable. At its essence, ratemaking requires a balancing of multiple interests, as the principles and objectives enumerated by Bonbright are often in tension with one another.

The tension among ratemaking objectives stems not only from the need to balance the interests of different parties (utilities, customer classes, and individual customers), but also the need to recover *historical* (embedded) costs while sending price signals that drive efficient *future* investments by affecting customer behavior.

Figure 1. Relationship Among Historical Costs, Future Costs, and Rate Design



In order to meet both of these objectives, rate design should be informed by two different types of analyses: embedded cost of service studies and forward-looking resource plans.

Cost-of-service studies help to establish relationships between utility costs and customer consumption, and allocate historical costs equitably by dividing the revenue requirement among customer classes based on each class's contribution to past investments and operating expenses.

Once the revenue requirement for each class has been set, the focus shifts to minimizing *future* costs, rather than simply recovering historical costs. Rates are designed to recover a set amount of revenues, but also to provide customers with appropriate price signals to help customers make efficient consumption and investment decisions (including investments in distributed solar) that will help minimize long-term system costs.

The connection between the two primary analyses and rate design can be summarized as follows:

- **Cost-of-Service Studies:** The primary purpose of embedded cost-of-service studies is to identify how to allocate the revenue requirement across the rate classes. The revenue requirement is largely the product of *historical* investments made by the utility to serve

[6] This discussion assumes continuation of the current electric utility structure. However, the electric utility model is beginning to evolve to accommodate a more distributed, customer-centric future, and to better address policy goals such as reducing greenhouse gas emissions. As such, the primary objectives of rate design may need to evolve as well.

various customer classes. While cost-of-service study results can be used to inform rate design, the cost-of-service study should not be used to dictate rate design, as it does not account for future costs.

- **Resource Planning:** The purpose of resource planning is to identify those *future* resources and investments that are cost-effective and in the public interest. Cost-effective resources may include distributed energy resources as an alternative to supply-side resources or investments in traditional utility infrastructure. This exercise provides an indication of how much distributed solar should be implemented or encouraged by the utility to cost-effectively meet future resource needs and minimize long-term system costs.

Rate design plays an important role in the procurement of distributed solar. Unlike traditional supply-side resources, distributed resources are rarely procured directly by a utility. Instead, distributed resources are generally installed by individual households and business owners. Since rate design can significantly impact the economics of distributed solar systems installed by such utility customers, it serves as a primary tool for stimulating or stifling the installation of additional distributed solar on the utility system.

Figure 2 summarizes the connections among cost of service studies, rate design, and resource planning, as well as the different types of costs considered in each analysis.

Figure 2. The Role of Cost of Service Studies, Rate Design, and Resource Planning

Cost of Service Studies	Rate Design	Resource Planning
•Goal: Cost allocation •Costs: Based on historical (embedded) costs •Connection: Used as one input to rate design, but does not dictate rate design.	•Goal: Revenue recovery, equity, efficient price signals •Costs: Addresses both historical and future costs •Connection: Price signals influence distributed solar and energy usage decisions	•Goal: Low-cost, reliable, safe, electric service •Costs: Based on future costs •Connection: Influenced by customer distributed solar and energy usage decisions. Also may influence future customer investment decisions.

Rate Design Options

The underlying rate design has a direct impact on the financial viability of distributed solar, as it determines the degree to which customers can reduce their electricity bills by investing in distributed solar. For example, increasing the fixed charge reduces the variable rate, effectively also lowering the net metering compensation rate, and can thereby substantially reduce incentives for customers to install distributed generation (Whited, Woolf, and Daniel 2016).

Fixed charges are not the only form of rate design that can impact the adoption of distributed solar. Other rate designs include:

- **Demand charges:** A demand charge is typically based on a customer's highest demand during any one period (e.g., hour or 15-minute period) of the month. A demand charge often reduces the economic attractiveness of solar, since solar generation generally reduces demand much less than it reduces energy consumption.[7]

- **Minimum bills:** A minimum bill is similar in appearance to a fixed charge, but only applies if the customer's bill would otherwise be lower than the minimum threshold. While a minimum bill ensures that all customers contribute a certain amount to the system each month, it does not distort the variable rate.

- **Time-of-use rates:** Time-of-use rates are a simple form of time-varying rate that has been used for decades. A time-of-use rate assigns each hour of the day to either a peak, off-peak, or shoulder period. The energy rate is then set to be highest during the peak hours and lowest during off-peak hours to better reflect the actual underlying costs of providing electricity during those hours. A time-of-use rate can be designed in many ways. The particular design of the rate can either increase or reduce the economic attractiveness of distributed solar.

- **Inclining block rates:** These rates are set so that the first block of kilowatt-hours consumed each month (e.g., the first 200 kWh) is billed at a lower rate than the next block of consumption. Because net metering offsets a customer's highest block of consumption first, inclining block rates can increase the value of distributed solar to the host customer.

- **Declining block rates:** Declining block rates are the inverse of inclining block rates. Under a declining block rate, the electricity price declines as energy consumption increases. These rates are rare for small residential and commercial customers, but are more common for large commercial and industrial customers.

2.2. Compensation Mechanisms for Distributed Solar

Net Metering

Net metering allows customers to offset their electricity consumption with their system's generation on a one-to-one basis at the end of a month. Net metering is currently the most common method of compensating solar generation for the individual home or business, having been adopted in more than 43 states (NCCETC 2016). It has traditionally been applied to customers who install solar on their premises, but is increasingly also being applied to community solar options (discussed below).

There are many varieties of net metering, and the specific program design parameters can impact the economic viability of distributed solar. These parameters may include:

- **Program caps:** A cap closes the net metering program to new customers once a certain penetration level has been reached.[8]

[7] Solar customers frequently have high usage during non-daylight hours when solar panels are not producing energy. In addition, an hour of cloud cover during daylight hours can cause a solar customers' usage from the grid to spike temporarily.

[8] Caps can be expressed in different ways, such as a percent of historical peak demand, a percent of electricity sales, or in absolute megawatts of capacity.

- **System size limits:** Often net metering is limited to customers with relatively small systems, such as under 500 kW. In some cases, the size limit is based on the host customer's load.
- **Treatment of excess generation:** Programs vary in terms of how excess generation is compensated (i.e., when total generation exceeds consumption for the month), and whether bill credits can be rolled over to the next month.
- **Underlying rate design:** Residential customers are typically billed through a combination of fixed charges and variable rates (in cents/kWh), with net metering compensation provided at (or close to) the variable rate.[9] Changes to the variable rate can affect the ability of customers to offset their bills with net metering credits.

Buy All/Sell All

A buy all/sell all tariff requires that all energy consumed by the host customer be purchased from the utility at the retail rate, and all generation be sold to the utility at a different rate. This rate may be higher or lower than the retail rate. Two variants of the Buy All/Sell All approach are value-of-solar tariffs and feed-in tariffs, described in the following sections.[10]

Value-of-Solar Tariffs

Value-of-solar tariffs are an alternative to net metering that is based on the estimated net value provided by solar generation. This net value can be estimated in many different ways, but the key elements typically include:

- Avoided energy costs (e.g., fuel, O&M)
- Avoided capacity (generation, transmission, and distribution)
- Avoided line losses
- Avoided environmental compliance costs
- Costs imposed on the system (integration costs, administrative costs)

An example of a jurisdiction that uses a value-of-solar tariff is Austin Energy. The value-of-solar rate is set on an annual basis through Austin Energy's budget process (City of Austin 2016). Because it is set

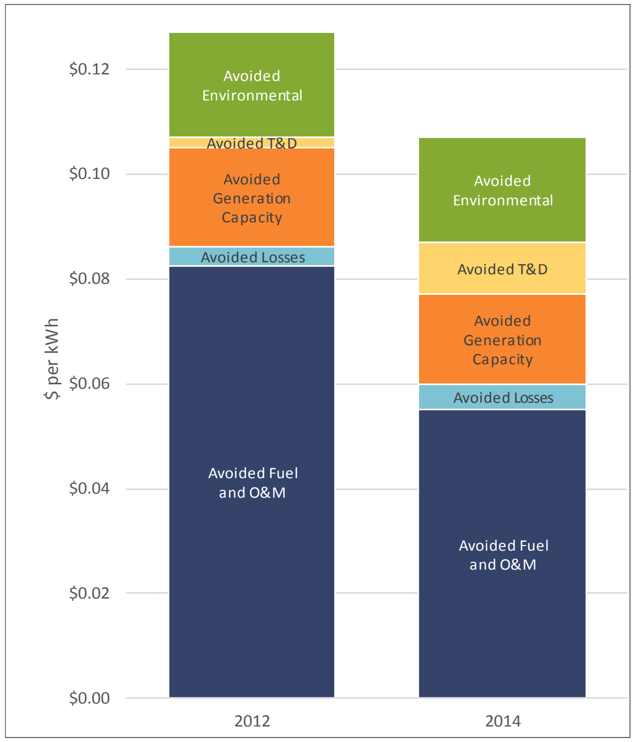
[9] This compensation rate does not include certain non-bypassable riders or fees.

[10] Some concern has been raised that a Buy All/Sell All mechanism may create tax liabilities for solar owners. Under a Buy All/Sell All mechanism, the owner may be viewed as engaging in the sale of electricity, the proceeds of which could constitute gross income.

annually, the rate fluctuates from year to year but is generally in the range of 10 to 12 cents per kilowatt-hour.

The methodology used by Austin Energy to calculate the value-of-solar rate was originally set in 2012 and considers loss savings, energy savings, generation capacity savings, fuel price hedge value, transmission and distribution capacity savings, and environmental benefits (Karl Rábago et al. 2016).

Figure 3. Austin Energy's Value-of-Solar Tariff 2012 and 2014



Value-of-solar tariffs may be applied in different ways. One method is to require that all energy consumed be purchased from the utility at the retail rate, while all generation is sold to the utility at the value-of-solar rate (i.e., a buy-all/sell-all arrangement). Under this option, no netting is permitted. Other jurisdictions may apply the value-of-solar rate only to excess generation, while any generation consumed behind the meter is effectively netted at the retail rate.

Feed-In Tariffs

A feed-in tariff (FIT) operates similarly to a value-of-solar tariff, in that it compensates solar generation at an administratively set value. However, the goal of a FIT differs from a value-of-solar tariff in that a FIT is designed explicitly to provide an incentive to install distributed generation. Typically FITs are used to stimulate early adoption of new technologies that would otherwise be cost-prohibitive for most customers. As such, the FIT is generally designed to allow distributed generation customers to earn a reasonable return on their investment.[11]

Instantaneous Netting

Net metering has traditionally netted energy consumption against generation at the end of a billing cycle (e.g., on a monthly basis). However, recently some jurisdictions (such as Hawaii) have begun to experiment with what can be called "instantaneous netting." Under this approach, any generation consumed on-site offsets grid-supplied energy at the retail rate on a near-instantaneous basis, while any generation exported to the grid is credited at a lower rate (Public Utilities Commission of Hawaii 2015).

[11] FITs have been widely used in Europe (particularly Germany), and on a more limited basis in the United States. For example, Portland General Electric (PGE) solar customers can choose a feed-in-tariff option called the Solar Payment Option, which currently compensates customers at a rate much higher than the net metering rate for a period of 15 years. *See:* PGE, "Solar Payment Option - Install Solar, Wind & More," https://www.portlandgeneral.com/residential/power-choices/renewable-power/install-solar-wind-more/solar-payment-option.

This rate structure encourages customers to use as much of their generation as possible (or store it in batteries), rather than pushing it onto the grid.

2.3. Additional Options

Community Solar and Other Virtual Net Metering

Community solar allows customers who are unable to install solar PV on their homes or businesses to benefit from the solar energy produced by an off-site solar installation (also called "virtual net metering").[12] Customers typically purchase a subscription or "share" of the electricity generated by the installation. Subscribers then receive both a charge for the subscription and a credit for the reduction in grid-supplied energy that are applied to their electricity bill. This credit may be equal to, more than, or less than the retail rate. Community solar installations have the advantage of removing some barriers to entry for installing solar systems. For example, community solar expands access to renters or other customers without suitable roof space, and to customers who have limited access to financing.

While community solar installations are typically much larger than the average residential system, smaller forms of virtual net metering are possible. In Massachusetts, a hybrid between large community solar arrangements and traditional net metering exists whereby an individual host customer can share his or her net metering credits with other customers who take service from the same utility (Public Utilities Commission of Hawaii 2015).

Renewable Energy Certificates and Solar Renewable Energy Certificates

Renewable Energy Certificates (RECs) and Solar Renewable Energy Certificates (SRECs) offer customers a financial incentive to install distributed solar by allowing customer generators to sell their RECs or SRECs to electricity suppliers, who are required by law to purchase a minimum number each year to comply with the jurisdiction's Renewable Portfolio Standard (RPS) or its RPS solar carve-out.

Currently 29 states and the District of Columbia have RPS policies, while a smaller number of states have solar carve-outs. States with solar carve-outs and an SREC market include Massachusetts, New Jersey, New Hampshire, Pennsylvania, Ohio, Delaware, Maryland, and the District of Columbia (Barbose 2016). However, many other states in the eastern United States are able to participate in the SREC markets of states with solar carve-outs (SREC Trade 2016). Some states have adopted an approach that does not use separate SRECs, but provides solar customers with a multiplier on their RECs (Barbose 2016). For example, a state might provide 3 kWh worth of RECs for 1 kWh generated by distributed solar.

Basic market forces determine the value of a REC or SREC: the supply of credits is determined by the quantity of eligible resources currently in place, while demand is determined by the jurisdiction's requirements. SREC prices are generally higher than RECs, and therefore tend to provide a stronger

[12] We note that the terms "community solar" and "virtual net metering" are used quite inconsistently across the country and also go by different names. For example, community solar may also be called "shared solar," "community distributed generation," or "neighborhood net metering."

financial incentive for customers to install solar technologies. However, both SREC and REC markets can be volatile, thereby increasing the financial risk for solar customers.

Loans, Rebates, and Tax Credits

Jurisdictions may provide a variety of incentives that reduce the up-front costs of installing solar technologies, including subsidized loans, up-front rebates, and tax credits. For example, the federal government currently offers a 30 percent investment tax credit for residential customers who install solar.[13] In addition, many jurisdictions offer installation rebates, such as Austin Energy's rebate of $0.70/watt (equivalent to approximately 18 percent of the current median cost per watt).[14]

---

[13] For more information, see the U.S. Department of Energy webpage at http://energy.gov/savings/residential-renewable-energy-tax-credit.

[14] For more information, see Austin Energy's website at http://austinenergy.com/wps/portal/ae/green-power/solar-solutions/solar-pv-systems/current-solar-incentive-levels.

3. DEVELOPMENT OF DISTRIBUTED SOLAR

A comprehensive analysis of distributed solar policy options should begin with an explicit articulation of state energy objectives and how they relate to distributed solar. The table below provides examples of such objectives and their relationship to distributed solar.

Table 2. Policy Objectives and Distributed Solar

Objective	Relationship to Distributed Solar Policy Choice
Reducing Electricity Costs and Risk	To the extent that distributed solar reduces system electricity costs and diversifies energy sources, decision-makers may seek to promote distributed solar. For example, distributed solar may be part of a strategy to relieve grid congestion and reduce the need for significant and expensive upgrades of the distribution system.
Environmental Goals	Regulators may wish to encourage development of distributed solar to reduce carbon emissions or achieve other state environmental goals.
Promoting Customer Control or Choice	A state may wish to support the ability of all customer classes to self-generate as an alternative to purchasing electricity from the utility and to reduce their energy bills. Distributed solar can help to achieve these objectives.
Employment	States may promote distributed solar as a means to increase the number of jobs, particularly those in the clean energy sector.
Protect Non-Solar Customers from Unreasonable Rate Impacts	Distributed solar may increase rates and bills for non-solar customers. The impact on low-income customers may be of particular concern. To address this, states may wish to limit the total penetration of distributed solar, or develop alternatives, such as community solar and low-income solar programs, that allow the benefits to be spread across a greater number of customers.

A policy decision such as a change in rate design will impact the economics of investing in distributed solar, and thus customers' willingness to adopt the technology. Changes in the adoption of distributed solar will in turn affect how much distributed solar is ultimately developed in the jurisdiction, which may have two key impacts on utility customers:

1. If distributed solar results in cost-shifting to non-solar customers, higher solar penetration levels will likely exacerbate this effect.
2. If distributed solar helps to reduce electricity rates and meet a state's solar energy objectives, higher penetration levels will benefit customers over the long term.

For these reasons, decision-makers should consider current penetration levels, as well as how a policy change will affect future customer adoption rates. Jurisdictions that are currently experiencing low adoption rates may want to consider how solar penetration may change under different policies, particularly if technology costs continue to fall (discussed more below).

Customer adoption rates are influenced by many factors, ranging from the ease of the interconnection process to the availability of loans or the ability to lease a solar system from a third-party installer. In this report, however, we focus solely on the compensation mechanisms and rate designs that influence customers' willingness to install distributed solar.[15] For simplicity, we assume that the customer is purchasing a system up-front, as not all states currently allow third-party leases or power purchase agreements.

To estimate the impact of a policy on a customer's willingness to purchase and install a solar system, it is first necessary to calculate the payback period for a typical solar customer under the current policy and the new policy.

Estimating the Payback Period

The steps to estimate the simple payback period for a single-owner solar installation are as follows:

1. **Reference Bill:** Calculate the customer's average monthly bill under the current rate structure and incentives without distributed solar, to provide a point of reference.[16] This will require knowing, at a minimum, the average annual consumption level (in kilowatt-hours) for a typical customer. For more sophisticated rate structures (such as time-of-use rates or demand charges), it may be necessary to know a range of customers' load profiles in order to accurately estimate the reference monthly bill(s). Estimates of future grid-supplied electricity prices will also be helpful.

2. **Upfront System Costs:** Estimate the cost of installing a solar array, using the most up-to-date prices and incentive levels possible. Online tools and datasets such as the Lawrence Berkeley National Lab's "Tracking the Sun" reports,[17] and the National Renewable Energy Laboratory's (NREL) Open PV Project[18] can help to inform this estimate.[19] Include any up-front incentives that a customer would receive, such as the federal tax credit, which allows residential taxpayers to deduct a percent of the cost of installing a solar energy system from their federal taxes.[20]

---

[15] In other words, the discussion that follows assumes that the interconnection process, permitting process, and other factors do not present unreasonable barriers to customers. If this is not the case, then estimates of customer adoption should be adjusted accordingly.

[16] If electricity rates are projected to increase faster than inflation, an escalation rate should be applied to the reference bill for each year of the analysis.

[17] Lawrence Berkeley National Lab's reports catalogue the trends in the installed price of residential and non-residential solar systems installed in the United States. These reports can be found at trackingthesun.lbl.gov.

[18] The National Renewable Energy Laboratory maintains a database of installed costs of distributed solar by year at https://openpv.nrel.gov/search.

[19] In 2015, the median installed price was $4.10 per watt for residential systems, $3.50 per watt for non-residential systems less than or equal to 500 kW in size, and $2.50 per watt for non-residential systems larger than 500 kW (Barbose and Darghouth 2016, 20).

[20] This tax credit will remain at 30 percent through 2019, but is then scheduled to be reduced to 26 percent in 2020 and 2021, and 22 percent in 2022 (U.S. Department of Energy 2016).

3. **Ongoing System Costs:** Estimate the annual costs to maintain the system. NREL provides current estimates of operations and maintenance costs on its website.[21]

4. **Generation:** Quantify the anticipated solar generation (in kWh) for a typical solar array using a tool such as the NREL's PV Watts calculator.[22]

5. **Bill Savings:** Using the solar generation profile estimated in Step 4, calculate the annual electricity bill for a customer with distributed solar, and then compare this to the annual electricity bill for a similar customer without distributed solar (as calculated in Step 1) in order to quantify the annual bill savings.

6. **Other Benefits:** Estimate any additional annual financial incentives that a customer would receive for the electricity produced by their system such as production incentives or the projected value of renewable energy credits (if applicable). Do not include the value of up-front incentives that reduce the initial cost of the solar system, as these were included in Step 2.

7. **Simple Payback Period:** If the benefits and costs are assumed to not vary from year-to-year, the system costs can simply be divided by the annual benefits to derive the simple payback period. Otherwise, incrementally subtract the annual benefits (the sum of bill savings calculated in Step 5 and other incentives calculated in Step 6) from the system costs (the sum of Step 2 and Step 3) to determine how many years will be required for a customer to recoup his or her investment.[23]

Once the simple payback period under the current rate structure and incentive levels is calculated, repeat the process for any new policies under consideration.

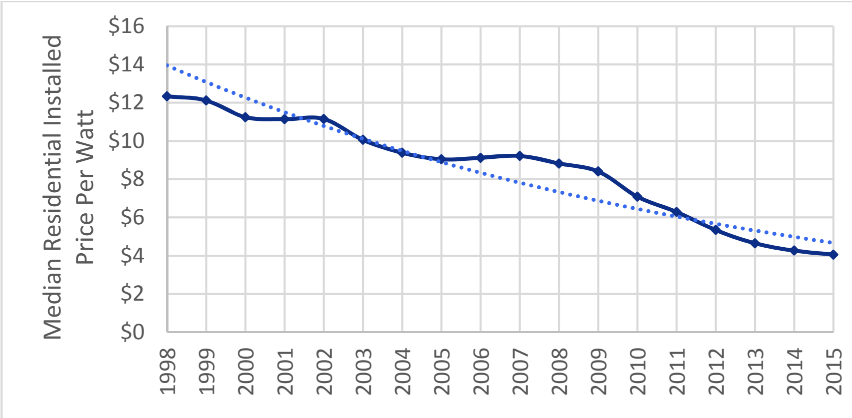
It should be noted that there are many factors that can influence the payback period and can change quickly. For example, the installed cost of solar has fallen dramatically in recent years, as shown in the figure below, based on data from Lawrence Berkeley National Laboratory (Barbose and Darghouth 2016). The price of electricity also may change significantly from year to year, particularly for jurisdictions where energy prices are driven by volatile oil or natural gas markets. For this reason, payback periods (and the penetration levels that rely on payback period estimates), should be updated periodically.

[21] In 2016, the estimated annual O&M costs for small residential systems was $21 (NREL 2016).

[22] The National Renewable Energy Laboratory's PV Watts calculator estimates the energy production from distributed solar systems throughout the world. The calculator also contains some cost information. http://pvwatts.nrel.gov/.

[23] The simple payback period calculation does not involve discounting.

Figure 4. Median Residential Installed Price of Solar



Source: Barbose and Darghouth, Tracking the Sun IX, August 2016.

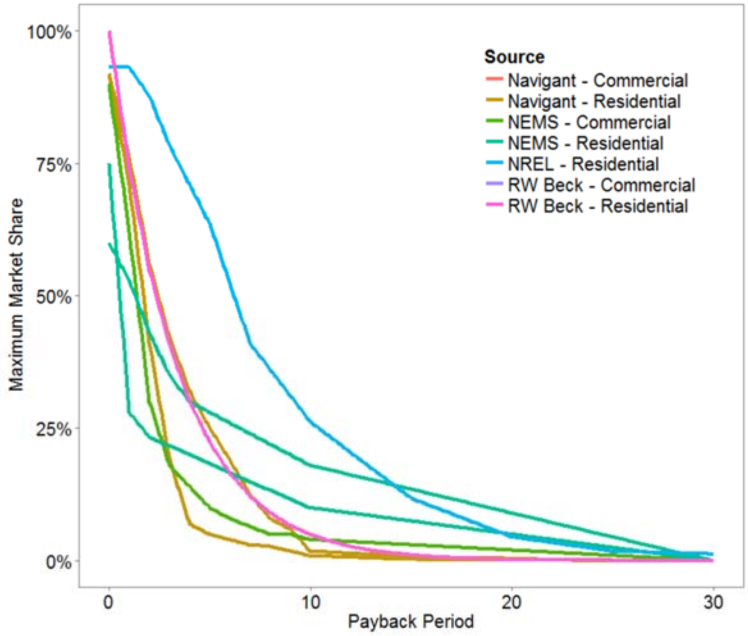
Customer Adoption Levels

The next step is to estimate the customer adoption levels for a certain payback period based on market penetration curves and estimates of the eligible population. Market penetration curves estimate the percentage of customers who will ultimately adopt a technology as a percentage of the total customers who would and could potentially install the technology.

Many customers cannot adopt solar because they have unsuitable roofs or do not own their residences. Other customers may have no interest in installing solar panels, even if they were provided for free. For example, out of 1,000,000 residential customers, perhaps only 650,000 customers own their residence and have roofs with little shading and an orientation suitable for solar. Thus the population of eligible customers should be determined for each jurisdiction based on surveys, home ownership rates, and analyses of rooftop suitability. If jurisdiction-specific estimates are not available, one can develop rough estimates from existing resources. One useful source is NREL, which developed estimates of the percentage of small buildings suitable for rooftop solar in each ZIP code using data on roof shading, tilt, and azimuth (Gagnon et al. 2016).

Once the population of eligible customers has been established, market penetration curves can be applied to estimate the proportion of the eligible population that would adopt solar based on a certain payback period. Ideally these curves will be developed for a particular jurisdiction using surveys. If this is not possible, curves developed for other jurisdictions can be used. For example, the graph below shows maximum market penetration curves for the residential and commercial classes as estimated by Navigant Consulting (Paidipati et al. 2008), the Energy Information Administration's National Energy Modeling System (NEMS) (EIA 2004), NREL (Sigrin and Drury 2014), and R.W. Beck (2009).

Figure 5. Market Penetration Curves from the Literature

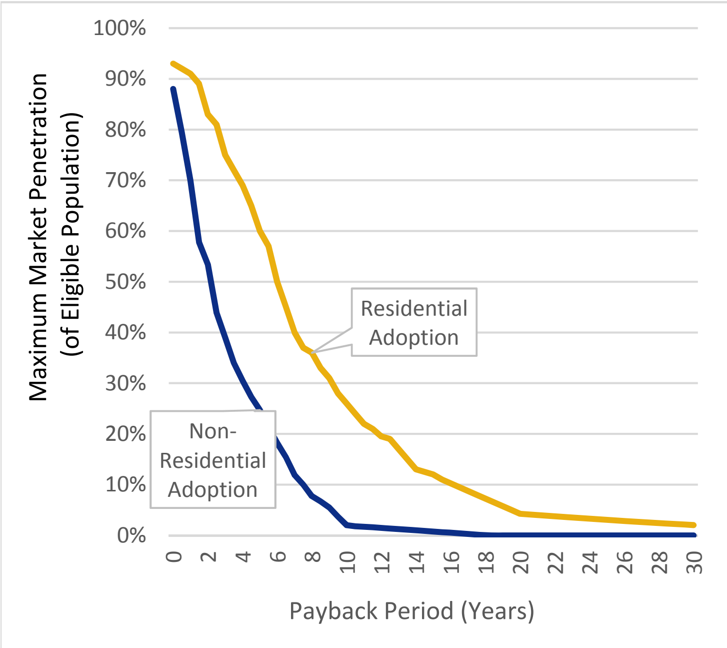


Source: Sigrin et al. 2016.

As demonstrated by Figure 5, estimates of market penetration can vary significantly based on what underlying data are used to estimate the curves and when the estimate was made. Such penetration curves may need to be adjusted over time as market factors change or as better data on customer adoption rates becomes available. These market penetration curves assume that there are no other substantial barriers to solar adoption (such as interconnection barriers, program caps, etc.). Moreover, it is unclear what effect alternative solar financing models (such as third-party leases) have on these curves. For this reason, we recommend that each jurisdiction conduct its own survey of customer willingness to adopt solar under different arrangements (including both customer ownership and third-party leases).

The market penetration curves recently adopted by NREL for its dSolar model (Sigrin et al. 2016) are approximated in the figure below. Using NREL's market penetration curves in Figure 6, a 15-year payback would be expected to result in 12 percent of possible residential customers being willing to purchase and install distributed solar, and 1 percent of possible commercial and industrial customers being willing to purchase and install distributed solar. It should be noted that the willingness of customers to adopt solar based on simple payback periods may not lead to actual project implementation if other types of barriers exist. For example, Navigant estimates that adoption levels may be reduced by as much as 60 percent if widespread interconnection challenges exist that create significant cost increases or result in project delays or cancellation (Paidipati et al. 2008, 10). On the other hand, if attractive financing options are available, actual penetration rates may be higher than those estimated based on payback periods.

Figure 6. Maximum Market Penetration Curves adopted by NREL



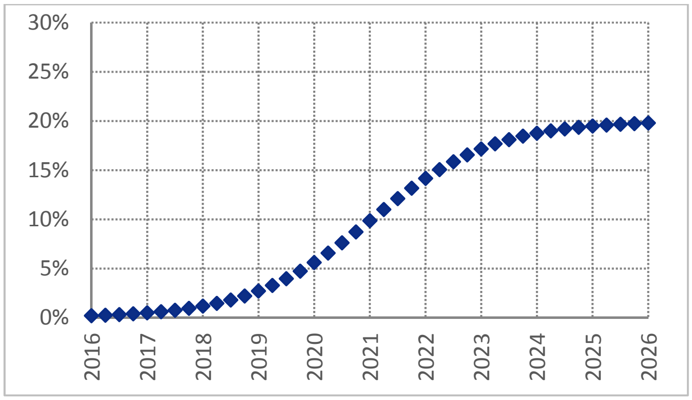
Source: Approximated from NREL's dSolar model as presented by Gagnon and Sigrin 2016.

Assuming that significant other barriers to installing distributed solar are not a factor, the penetration levels indicated by market penetration curves can be expressed as penetration levels for each rate class. They can also be converted to penetration as a percent of system peak demand or of energy sales. These expected penetration levels should be estimated for each policy option under consideration, as they are used to determine the net benefits provided by each policy option (described in the next section).

However, it is important to remember that the payback period is likely to change from year-to-year, and therefore the ultimate penetration of distributed solar estimated this year may be markedly different than an estimate made five years from now. To address this, policymakers may instead want to estimate the near-term penetration level (e.g., five years in the future), and revisit the estimate every few years.

To determine the likely penetration level in five years, rather than the ultimate penetration level, an expected adoption trajectory is required. New technology adoption often follows an "S-curve," which can be specified using the Bass Diffusion Model (Bass 1969). Under this model, growth begins slowly, enters into a rapid growth phase, and then begins to slow as it nears market saturation (i.e., the maximum percentage of the population that might ultimately adopt the product). A hypothetical S-curve for distributed solar is shown in Figure 7, below, based on the assumption that the market will saturate at 20 percent over a 10-year period.[24]

Figure 7. Hypothetical S-Curve of Distributed Solar Adoption



Note: Assumes that market saturation at 20 percent occurs in 10 years.

However, such adoption trajectories should be viewed as a snapshot in time, based on current payback periods. As factors influencing the payback period change (such as the price of solar panels), the market saturation level will also change. This key factor is not captured by the original Bass Diffusion Model, and thus the model must be re-estimated as financial parameters change, or an alternative model should be used (Chandrasekaran and Tellis 2007).

[24] The shape that the S-curve takes will vary based on parameters referred to as the "coefficient of innovation" and the "coefficient of imitation." Further research is required to accurately specify these parameters.

4. DISTRIBUTED SOLAR COST-EFFECTIVENESS

The basic premise of cost-benefit analysis is simple: All of the relevant costs of a resource are forecasted over a long-term planning horizon, along with all of the relevant benefits (otherwise referred to as the avoided costs). If the cumulative present value of the benefits outweighs the cumulative present value of the costs, the resource is considered cost-effective.[25] However, the magnitudes of the benefits and costs can vary considerably depending upon which costs and benefits are relevant. Several different cost-effectiveness methodologies are used to determine which costs and benefits are included in the analysis, as discussed in the section on cost-effectiveness tests below.

4.1. Costs and Benefits

Distributed solar can offer the utility system and society a host of benefits, ranging from avoided energy and capacity costs, to reduced environmental impacts. At the same time, distributed solar may impose administration and integration costs on the system. Table 3 lists many of the most frequently quantified benefits and costs.

Table 3. Potential Distributed Solar Costs and Benefits

Benefits
Avoided Energy Costs
Avoided Generation Capacity Costs
Avoided Losses
Avoided Transmission & Distribution Costs
Avoided Environmental Compliance Costs
Avoided Ancillary Services
Reduced Risk
Environmental Benefits
Costs
Administration costs
Interconnection Costs
Distribution System Upgrades
Participant Costs

It is important to note that the costs and benefits may vary greatly over time, due to changes in penetration levels and changes in avoided costs (such as changes in the price of natural gas). For example, distributed solar penetration of less than 5 percent may impose only very small administrative and integration costs on the system. However, penetration levels of 20 percent or more may impose significant costs on the system, stemming from the need to upgrade distribution system equipment to handle large amounts of solar generation. Another cost could be the need to install distributed generator visibility and control devices. For this reason, it is recommended that avoided costs be re-

[25] Where costs and benefits are difficult to quantify, reasonable approximations should be used until more detailed information is available (Woolf et al. 2014).

evaluated periodically, particularly if penetration levels are growing quickly, or if fuel prices are changing rapidly.

4.2. Cost-Effectiveness Tests

Distributed solar studies generally use cost-effectiveness methodologies that are based on, or at least consistent with, the methodologies that are commonly used for assessing energy efficiency cost-effectiveness. Five cost-effectiveness tests have long been used to analyze energy efficiency's costs and benefits from various perspectives. These tests are based on the California Standard Practice Manual (California Public Utilities Commission 2001).

In recent years, however, these tests have been subject to much debate. Many jurisdictions, including California, have been wrestling with questions regarding which of these tests should be used for evaluating energy efficiency and how. In response to this challenge, the National Efficiency Screening Project was formed several years ago to help improve the way that jurisdictions analyze the cost-effectiveness of energy efficiency resources (NESP 2014). NESP is currently in the process of preparing a National Standard Practice Manual to provide guidance on energy efficiency cost-effectiveness practices (National Efficiency Screening Project Forthcoming).

The main point from this debate on energy efficiency cost-effectiveness, for the purpose of this study, is that it is essential to understand precisely what information each test can provide, and what that information indicates regarding the cost-effectiveness of distributed solar resources. Each of the tests has advantages and limitations that must be considered when applying them. The following subsections describe the information that each of the tests can provide; and Section 4.3 describes what that information means for understanding the cost-effectiveness of distributed solar resources.

It is essential to understand precisely what information each test can provide, and what that information indicates regarding the cost-effectiveness of distributed solar resources.

The Utility Cost Test[26]

The purpose of the Utility Cost Test is to indicate whether a resource's benefits will exceed its costs from the perspective of the utility system. It does not, as the name implies, represent the perspective of the utility in terms of utility management or utility investors. It instead represents the perspective of the utility system. In other words, the Utility Cost Test represents the perspective of utility customers as a whole.

The Utility Cost Test should include all utility system costs that impact revenue requirements when additional distributed solar is added to the system. The utility system costs are comprised of all costs that the utility must recover from customers, such as net metering administration costs, interconnection costs beyond what is borne by the customer, and distribution system upgrades.

[26] This test is also referred to as the "Program Administrator Cost Test."

It is important to note that certain utility system costs—such as the cost of complying with an RPS or solar carve-out—are not incremental costs imposed by additional distributed solar, and should therefore not be included. The costs associated with such compliance (e.g., SRECs) occur as the result of the state's decision to create an RPS solar carve-out. These costs would be incurred by the utility regardless of whether additional distributed solar is implemented (assuming that the utility would have to procure the solar from the market or pay an alternative compliance fee). As such, SRECs do not get counted as a cost or benefit under the Utility Cost Test.[27]

One key limitation of the Utility Cost Test is that it does not reflect the extent to which distributed solar resources will achieve energy policy goals (beyond the goal of reducing cost).

The Utility Cost Test should also include all utility system costs that are avoided by the distributed solar resource, including avoided energy costs, avoided generation capacity, market price suppression effects, avoided transmission and distribution costs, avoided line losses, and avoided environmental compliance costs.

The key advantage of the Utility Cost Test is its simplicity; it indicates how distributed solar resources will affect electric utility costs to all customers as a whole. It is the methodology that utilities have used for years to assess the costs and benefits of electricity resource investments, and is the primary criterion for assessing costs and benefits in the context of integrated resource planning.

One key limitation of the Utility Cost Test is that it does not reflect the extent to which distributed solar resources will achieve energy policy goals (except for the goal of reducing costs). Most jurisdictions establish distributed solar policies for the explicit purpose of increasing fuel diversity and independence, reducing environmental impacts, and increasing local jobs and economic development. The Utility Cost Test, by design, does not reflect these types of benefits.

The Total Resource Cost Test

The purpose of the Total Resource Cost (TRC) Test is to indicate whether the benefits of distributed solar resources will exceed their costs from the perspective of the utility system and the host solar customer. This test, in theory, includes all costs and benefits of the Utility Cost Test, plus all costs and benefits to solar customers. Customer costs include all equipment, installation, and maintenance costs for the distributed solar facility, or solar lease payments (if applicable). The benefits include any benefits experienced by the solar customer (beside the benefits of reduced bills).[28] In theory, these non-bill customer benefits could reflect customer benefits such as reduced environmental impacts. In practice,

[27] The question of whether or not a jurisdiction's RPS policy or solar carve-out is cost-effective and whether it should be pursued should be studied separately. For the purposes of this report, such policies are taken as a given and must be complied with in some manner.

[28] By design, the TRC Test includes the benefits (i.e., avoided costs) of the utility system. Customer bill reductions should not be included as a benefit in this test, because that would double-count some of these avoided costs. The Participant Cost Test is used to more specifically account for solar customer bill savings.

these non-bill benefits to solar customers are rarely properly estimated and included in solar cost-effectiveness analyses.[29]

The main advantage of the TRC Test is that it provides more comprehensive information than the Utility Cost Test, by including the impacts on participating customers. In this way the "total cost" of the resource is reflected in the test, regardless of who pays for those costs.

However, the TRC Test might not accurately capture the benefits to solar customers. The primary benefits to the host solar customer are in the form of customer bill savings, but the TRC Test does not include customer bill savings; instead the test includes avoided utility system costs. In those jurisdictions where retail rates (which determine customer bill savings) are different from utility avoided costs, this test will not accurately capture the impact on solar customers.

Further, in practice the TRC Test does not account for the non-bill benefits to solar customers. Since many solar customers install solar facilities for the purpose of reducing their environmental impact, this could lead to a significant understatement of the benefits in the TRC Test.

Because of these two limitations, the TRC Test might not represent the impacts on the utility system and the solar customers, as it purports to do. Instead, it would be more accurate to describe the TRC Test, as it is typically applied, as a limited version of the Societal Cost Test, because it includes the total resource costs, but not necessarily the total resource benefits.

The Societal Cost Test

The purpose of the Societal Cost Test is to indicate whether the benefits of distributed solar resources will exceed their costs from the perspective of society as a whole. This test should include all the costs and benefits of the Total Resource Cost Test, plus additional costs and benefits on society. The primary costs and benefits that are included in this test, when it is applied to distributed solar resources, are the environmental impacts and the net impacts on jobs and economic development.

The main advantage of the Societal Cost Test is that it provides the most comprehensive picture of the total costs and benefits of a distributed solar resource. Further, it is the only test that accounts for the benefits associated with a jurisdiction's energy policy goals (beyond the goals of reducing utility system costs or solar customer costs).

The Societal Cost Test is the only test that fully accounts for a jurisdiction's energy policy goals (beyond the goal of reducing costs).

The main limitation of the Societal Cost Test when used for utility resource planning is that it might place too much emphasis on societal impacts if it is the only test considered. If the societal impacts of distributed solar resources are particularly high relative to the utility system costs and benefits, this test might place undue emphasis on achieving energy policy goals over the goal of reducing electricity system costs. Another limitation of the Societal Cost Test is that it can

[29] Some states have modified the TRC test to include a value for non-energy benefits.

be difficult to fully implement, as many externalities are difficult to fully monetize.

The Rate Impact Measure Test

The purpose of the Rate Impact Measure (RIM) Test is to indicate whether distributed solar resources will increase or decrease electricity rates (i.e., prices). This test is sometimes used to indicate the impacts on non-solar customers, because these customers might experience rate impacts as a result of generation from distributed solar facilities. However, as explained more below, the RIM Test has several fundamental flaws and should not be used to evaluate rate impacts. Instead, a more comprehensive rate and bill impact assessment should be performed (as discussed in the following chapter).

Under the California Standard Practice Manual, the RIM Test includes the same costs and benefits included in the Utility Cost Test, plus the addition of "lost revenues." Lost revenues are caused by the reduced electricity consumption of solar customers, and are equal to the amount of revenues that utilities need to recover from non-solar customers in order to recover the fixed costs embedded in electricity rates.[30] However, these lost revenues are simply an artifact of recovering the same amount of revenues over fewer sales, and are not a new cost to the utility system.

The main (and only) advantage of the RIM Test is that it indicates whether a resource will increase or decrease electricity rates on average over the long term. Unfortunately, it fails to provide other useful information regarding rate and bill impacts.

One of the main limitations of the RIM Test is that it conflates cost-effectiveness and cost-shifting. These are two separate effects that can only be fully understood with separate analysis. Cost-effectiveness analyses should include only future costs, and should seek ways to minimize those future costs (along with achieving other policy goals). The RIM Test includes lost revenues, which are a result of historical costs (i.e., sunk costs) that are embedded in electricity rates. These costs would exist with or without distributed solar, and therefore are not a new cost to the utility system caused by distributed solar.

The main limitation of the RIM Test is that it conflates cost-effectiveness with cost-shifting. These are two separate effects that can only be fully understood with separate analysis.

Combining future costs and historical costs in one test makes it difficult to understand either cost-effectiveness or cost-shifting. It is also inconsistent with standard microeconomic theory, which requires that sunk costs not be included in cost-effectiveness analyses.[31]

Further, the RIM Test does not provide the information that utilities and regulators need to assess the magnitude of rate impacts caused by distributed solar resources. This test simply indicates whether rates will increase or decrease as a result of these resources. A RIM Test might result in a benefit-cost ratio of 0.9, for example, but this does not provide any indication of whether the rate impact is

[30] The lost revenues include the costs associated with historical investments in electricity infrastructure, including a financial return on those investments.

[31] If sunk costs are included, they should be included in both the base case (without distributed solar) and the case with distributed solar, which leads them to cancel each other out.

significant or *de minimus*. In other words, it provides no information regarding whether the rate impacts are likely to be reasonable, given the other benefits of distributed solar resources. A separate rate impact analysis, described in Section 5 below, can provide more useful metrics for this purpose, such as the percent change in rates or the average change in customer monthly bills.

The Participant Cost Test

The Participant Cost Test indicates whether a distributed solar resource is cost-effective from the perspective of the participant (the host solar customer). This test includes all of the impacts on the solar customer, but no other impacts. This test is fundamentally different from the other four tests described here in that the benefits are based on avoided electricity rates, not avoided utility system costs.

The Participant Cost Test should include all customer equipment, installation, and maintenance costs for the distributed solar facility, or solar lease payments (if applicable). The benefits should include all the benefits experienced by the solar customer, including reductions in electricity bills, as well as non-bill benefits such as reduced environmental impacts. In practice, these non-bill benefits to solar customers are rarely, if ever, estimated and included in cost-effectiveness analyses of distributed solar resources.

The main advantage of the Participant Cost Test is that it provides an indication of the extent to which host customers would benefit from installing distributed solar facilities. The main limitation of the Participant Cost Test is that it does not provide information regarding the impacts of distributed solar resources relative to other electricity resources, and provides no information regarding the impacts on the electricity system as a whole.

The extent to which customers are likely to adopt distributed solar resources will affect the need for future electricity resources, including generation, transmission, and distribution facilities.

Nonetheless, the impacts on solar customer are connected to electricity resource planning in one important way. The extent to which customers are likely to adopt distributed solar resources will affect the need for future electricity resources, including generation, transmission, and distribution facilities. Therefore, customer adoption rates will affect the future resource scenarios that should be used in cost-effectiveness analyses. However, conventional application of the Participant Cost Test may not provide sufficient information regarding customer adoption, as there is little information directly linking the results of the Participant Cost Test to penetration rates. For this reason, calculating the customer payback period instead of, or in addition to, the Participant Cost Test provides a more useful and direct means of determining the extent to which customers are likely to install distributed solar resources.

4.3. Implications of the Tests for Distributed Resources

Jurisdictions should consider several perspectives, when assessing the cost-effectiveness of distributed solar resources. As noted above, each cost-effectiveness test provides different types of information. The key implications for each test for distributed solar are as follows:

- Utility Cost Test: This tests provides the simplest, most direct indication of the future costs and benefits of distributed solar resources on all customers as a whole. It is a fundamental metric used in utility resource decision-making, including integrated resource planning. Therefore, it should be one of the primary tests used to indicate cost-effectiveness of distributed solar resources.

- Total Resource Cost Test: This test attempts to indicate the future costs and benefits of distributed solar resources on the utility system and solar customers. However, it does not accurately capture the benefits to solar customers. Further, while it includes "total" resource costs, it does not include total resource benefits, particularly those related to energy policy goals. Therefore, this test should be used with caution, and with an understanding of its limitations, when assessing the cost-effectiveness of distributed solar resources.

- Societal Cost Test: This test provides the most comprehensive indication of future costs and benefits of distributed solar resources, including the impacts related to energy policy goals, such as promoting local jobs and economic development and reducing environmental impacts. Therefore, it should be one of the primary tests, along with the Utility Cost Test, used to indicate cost-effectiveness of distributed solar resources.

- Rate Impact Measure Test: This test is different from the other tests in that it attempts to measure cost-shifting and impacts on non-solar customers. However, this test conflates cost-effectiveness with cost-shifting, and therefore does not provide useful information regarding either. Therefore, it should not be used to indicate the cost-effectiveness of distributed solar resources. Instead, cost-shifting from distributed solar resources should be analyzed using separate rate impact analyses, as described in Section 5.

- Participant Cost Test: This test provides a relatively narrow indication of the future costs and benefits of distributed solar resources on solar customers only. It does not provide information regarding the cost-effectiveness of distributed solar resources relative to other electricity resources. In other words, it does not provide much useful information for the purpose of comparing future resource options. The solar participant's perspective, however, is useful for estimating the extent to which different policies will encourage the development of distributed solar resources. Analyses of customer payback periods and adoption rates, as described in Section 3, are more useful for this purpose than the Participant Cost Test.

In sum, jurisdictions should generally use Utility Cost Test and the Societal Cost Test to understand the impacts of distributed solar, while the TRC Test should be used only with caution. Cost-shifting should be addressed using a rate impact analysis, not the RIM Test. And the solar participant's perspective should be addressed using a customer payback period and adoption rate analysis.

It is also important to recognize that each jurisdiction can choose how much emphasis to place on any one of the tests. Those with a greater focus on reducing utility system costs should give more weight to the Utility Cost Test; while those with a greater focus on achieving other energy policy goals should give more weight to the Societal Cost Test.

4.4. Cost-Effectiveness Tests Example

The results of distributed solar cost-effectiveness analyses tend to vary considerably by jurisdiction, particularly because the retail rates and the avoided costs vary significantly, and because these studies often use different methodologies and assumptions when accounting for costs and benefits.

To show how the choice of cost-effectiveness test can impact the results of a study, we have chosen an example analysis and present the cost-effectiveness results from the utility system perspective, the total resource cost perspective, and the societal perspective. The purpose of this example is not to endorse any of the studies or draw any conclusions about cost-effectiveness in any one jurisdiction, but is simply intended to illustrate the points made above.

Figure 8 presents an example of the cost-effectiveness results for a city in Pennsylvania, based upon the Utility Cost Test.[32] It shows the long-term average costs to the utility system, relative to the long-term average benefits to the utility system. Results of the Utility Cost Test generally show that distributed solar resources are very cost effective. This is because a large portion of the resource cost—the equipment, installation, and maintenance costs—are borne by the host customer, not the utility or the other customers.

Figure 8. Cost-Effectiveness Results for the Utility Cost Test

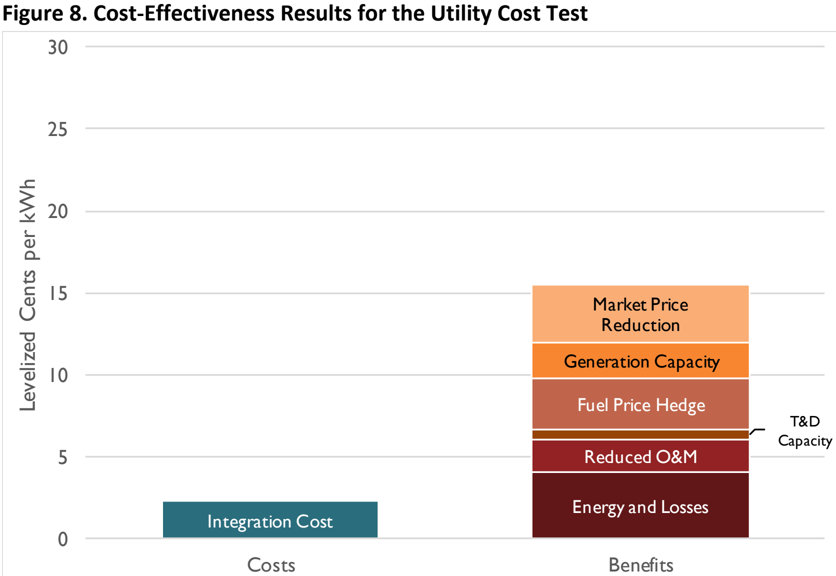


Figure 9 below presents the cost-effectiveness results for the same location, based upon the TRC Test. In this case the costs of the (privately financed) distributed solar facility are added to the utility costs, and the costs slightly outweigh the benefits.

[32] The utility and societal avoided cost results for Figure 8 through Figure 10 are derived from Perez, Norris, and Hoff (2012) for Pittsburgh.

Figure 9. Cost-Effectiveness Results for the TRC Test

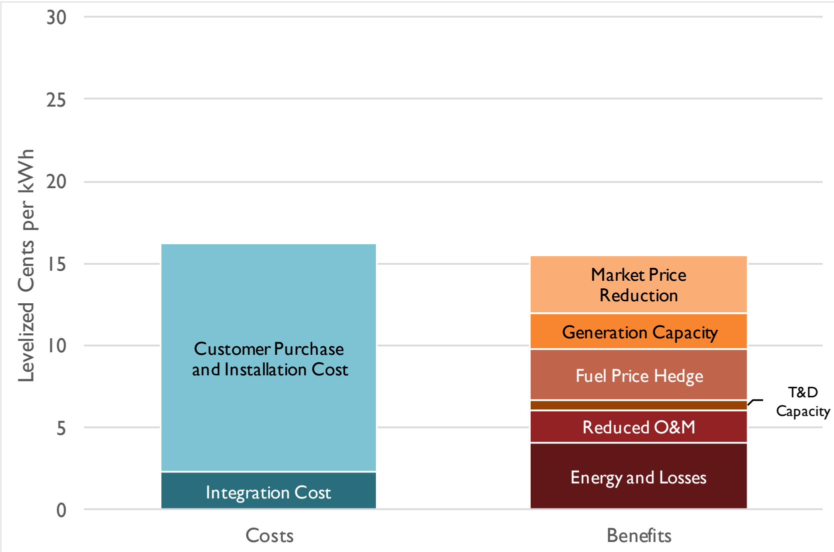
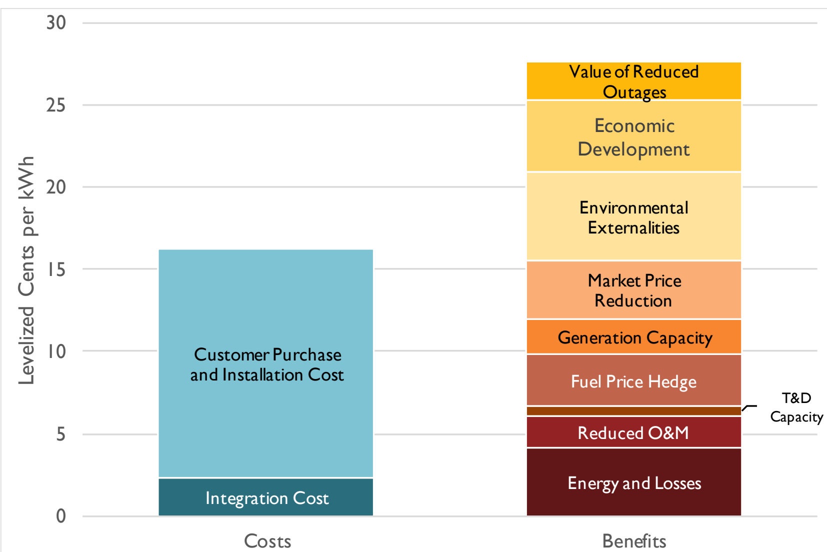


Figure 10 presents the cost-effectiveness results for the same location, based upon the Societal Cost Test. In this case the societal benefits are added to the utility system benefits.

Figure 10. Cost-Effectiveness Results from Recent Studies – Societal Cost Test[33]



As indicated in the figures above, the choice of test used to assess cost-effectiveness will have a significant impact on the outcome of the analysis—even within a single study using consistent methodologies and assumptions. This is why it is so important to understand the information that each test does, and does not, provide.

[33] Note that "societal" benefits may be defined differently from jurisdiction to jurisdiction. For example, economic development benefits (i.e., jobs) are not always included.

5. COST-SHIFTING FROM DISTRIBUTED SOLAR

The potential for cost-shifting from solar to non-solar customers is one of the most important issues facing utilities and regulators in essentially every jurisdiction addressing this topic. Therefore, cost-shifting warrants considerable attention and should be analyzed as concretely and comprehensively as possible. Although the RIM Test attempts to address cost-shifting, it does not provide sufficient information necessary to fully understand and address this important issue, as described in Section 4.2.

Cost-shifting from distributed solar customers to non-solar customers occurs in the form of rate impacts, which results in higher bills for non-solar customers. Rates increase or decrease to reflect changes in electricity sales levels, changes in costs, or both. A comprehensive, long-term rate impact analysis will account for both of these effects, thereby providing the necessary information to help understand this critical issue.

When evaluating cost-shifting, it is important to also analyze both long-term and short-term rate impacts to understand the full picture. Generally, the benefits of distributed solar may not be realized for several years while a decrease in electricity sales occurs immediately. This can result in short-term rate increases, followed by long-term rate decreases. Thus a short-term rate impact analysis will not fully capture the impacts of distributed solar, and should not be performed without also evaluating long-term rate impacts.

In their most simplified form, electricity rates are set by dividing the utility's revenue requirement (in millions of dollars) over its sales (typically measured in kilowatt-hours).

$$Rates = \frac{Revenue\ Requirement}{Sales}$$

Thus rate impacts are primarily caused by two factors:

1. **Changes in costs:** Holding all else constant, if a utility's revenue requirement decreases, rates will decrease. Conversely, if a utility's revenue requirement increases, rates will increase. Distributed solar can avoid many utility costs, which can reduce utility revenue requirements. Distributed solar can also impose costs on the utility system (such as interconnection and distribution system upgrade costs.)

2. **Changes in electricity sales:** If a utility has to recover its revenues over fewer sales, rates will increase. This is commonly referred to as recovering "lost revenues" and is an artifact of the decrease in sales, not any change in actual costs incurred by the utility. Rather, the rate increase is due solely to the *distribution* of costs among solar and non-

solar utility customers. This impact is therefore only relevant to a rate impact analysis, which captures distributional impacts, not a cost-benefit analysis.[34]

Whether distributed solar increases or decreases rates will depend on the magnitude and direction of each of these factors. If in one year distributed solar decreases the utility's revenue requirement by a larger percentage than sales decrease, rates can decline.[35] In reality, cost reductions may not reduce a utility's revenue requirement substantially in the near-term for two reasons.

The benefits of distributed solar may not be realized for several years while a decrease in sales occurs immediately. For this reason, both a long-run and a short-run analysis of rate impacts offer valuable information.

First, in the short-term, the utility will still have to recover its sunk costs—the investments that the utility made in the past and amortized over many years.[36] These sunk costs will not be reduced by distributed solar, but will continue to be recovered through the utility's revenue requirement until they have been fully depreciated. Thus a decrease of 5 percent in next year's costs will not necessarily result in a decrease of 5 percent in total revenue requirements, since a large portion of a utility's revenue requirement stems from the recovery of historical investments.

Second, distributed solar can help to avoid certain utility investments, and these avoided costs should be accounted for in a cost-benefit analysis. In the long run, if the average net avoided costs to the utility system (in dollars per kilowatt-hour) are equal to the credit received by the solar customer, then no cost-shifting over the study period is expected to occur.[37] If the net avoided costs are less than the credit received by the solar customer, rates will increase and cost-shifting will occur. Similarly, if net avoided costs are greater than the credit received, then a reduction in rates may occur.

These potential impacts are illustrated in the figure below. The column on the left shows the magnitude of the net utility system costs avoided by each kilowatt-hour of solar generation. For a net metered customer, the credit is equal to the retail rate. If the net avoided costs are lower than the retail rate (the middle bar), then each kilowatt-hour of solar generation will result in lost revenues to the utility that

[34] Cost-benefit analyses generally ignore distributional impacts, adhering instead to the Kaldor-Hicks efficiency criterion. This criterion focuses on maximizing total net benefits so that, in theory, any losers could be compensated and made no worse off than they were before. Although cost-benefit analyses can be made to incorporate "distributional weights" to account for equity concerns, this is difficult to do and rarely done in practice. A rate and bill impact analysis offers a means of assessing distributional impacts in a manner that is more transparent, comprehensive, and theoretically sound than the traditional application of the RIM Test.

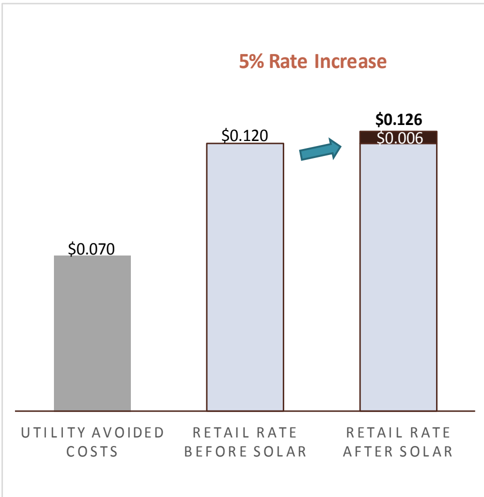
[35] Whether or not rates actually decrease is dependent upon whether the utility's revenues are recalculated and new rates are set. However, there may be a lag of several years before a new rate case commences and new rates are set.

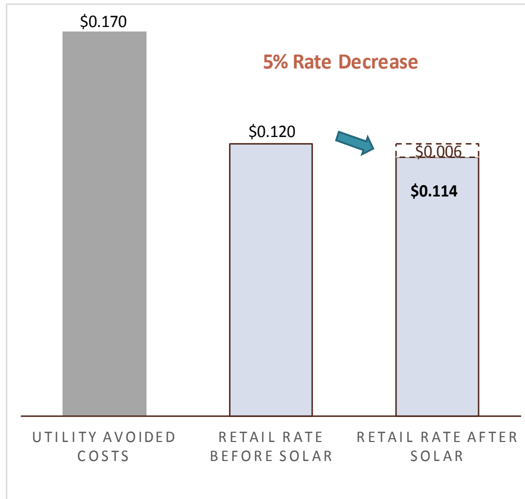
[36] The utility is also allowed the opportunity to recover a return on its investments.

[37] The net avoided costs account for both the benefits and any additional costs imposed on the utility system by distributed solar.

increase rates, as shown by the right bar. Conversely, higher net avoided costs will reduce rates, as shown in the graph on the right.

Figure 11. Rate Impacts Associated with Different Levels of Net Avoided Costs





While the utility system avoided costs vary from jurisdiction to jurisdiction, many recent studies have estimated levelized avoided costs in excess of the retail rate, on a long-term levelized basis.[38] For each state where the avoided costs exceed the retail rate, distributed solar will likely lead to a reduction in rates over the long-term, and vice versa.[39]

As noted above, however, the timing of any benefits to the utility system is important to include in a rate impact analysis. Distributed solar will not help to defer or avoid capacity upgrades when no upgrades are planned for the near term. In time, generation, transmission, or distribution capacity upgrades may eventually be needed, and distributed solar can help to defer or avoid these investments, particularly when such investments are driven by additional load growth.[40] However, such benefits will only help to reduce revenue requirements in the years that they would have otherwise occurred.

Rate impacts should be presented in meaningful terms, such as the percent change in rates, as well as the annual and monthly bill impacts per customer (i.e., in dollars per customer per month or year).

[38] See, for example, Norris et al. 2015; Stanton et al. 2014; Perez, Norris, and Hoff 2012; Beach and McGuire 2013b; Hallock and Sargent 2015.

[39] Because utility system investments are often lumpy, many jurisdictions will experience short-term rate increases, even though rates may decline over the long run.

[40] To the extent that solar generation reduces peak loads on the distribution system, new infrastructure (such as substation upgrades) may be deferred or even entirely avoided. Solar generation may also help to provide thermal performance benefits through reducing peak demand, minimizing system losses, and improving reactive demand compensation.

In sum, because the benefits of distributed solar may not be realized for several years while a decrease in sales occurs immediately, jurisdictions often experience short-term rate increases. For this reason, both a long-run and a short-run analysis of rate impacts offer valuable information, and a thorough analysis of rate impacts resulting from distributed solar should include both the long-term change in customer rates as well as the year-to-year impacts.

The manner in which the results of a rate impact analysis are presented are important. Rate impact results should be presented in meaningful terms, such as the percent change in rates, as well as the annual and monthly bill impacts per customer (i.e., in dollars per customer per month or year).

A rate impact analysis provides a critical piece of information for decision-makers when determining distributed solar policies. The analysis should be performed for the current set of distributed solar policies, as well as any new policy considered to determine the degree to which both short-term and long-term rates are affected. Ultimately, the objective is to strike a balance between encouraging cost-effective resource investments and preventing unreasonable rate impacts to non-solar customers. Decision-makers may choose to tolerate moderate short-term increases in rates in order to achieve long-term system cost reductions, or they may decide that rate impacts on non-solar customers need to be mitigated by implementing other policies specifically aimed at addressing these impacts. Policies designed to mitigate rate impacts may include changes to rate design, or other options discussed in Section 2.

6. SUMMARY AND EXAMPLE OF THE ANALYTICAL FRAMEWORK

6.1. Implementation Steps of the Analytical Framework

The results of the three analyses described above can be pulled together into a single framework that can be used to evaluate different distributed solar resource policies in a transparent, data-driven regulatory process.[41] The framework proposed here can be used to assess the impacts of different rate designs or solar compensation mechanisms on the development, cost-effectiveness, and cost-shifting resulting from the distributed solar resources. If one policy option indicates an unreasonable amount of cost-shifting, then alternative policies may be warranted to mitigate cost-shifting.[42] If, on the other hand, the policy option results in very little solar development, and will not allow the jurisdiction to meet its energy policy goals, then alternative policies may be warranted to increase solar development.

The framework proposed here includes several steps that decision-makers or other stakeholders can take to assess the implications of different distributed solar policies. These steps are summarized in Table 4.

Table 4. Steps Required to Assess Distributed Solar Policies

Step 1	Articulate state policy goals regarding distributed solar resources.
Step 2	Articulate all the existing regulatory policies related to distributed solar resources.
Step 3	Identify all of the new distributed solar policies that warrant evaluation.
Step 4	Estimate the customer adoption rates under current solar policies, and new solar policies.
Step 5	Estimate the cost-effectiveness of distributed solar under current policies and new policies.
Step 6	Estimate the extent of cost-shifting under current solar policies, and new solar policies.
Step 7	Use the information provided in the previous steps to assess the various policy options.

6.2. Example Application of the Framework

An example will help to illustrate how a jurisdiction might apply the framework:

Step 1—Policy Goals: Consider a jurisdiction that has articulated a desire to promote cost-effective renewable distributed energy resources, to the extent that rate impacts are not unreasonable. Although current penetration levels of distributed solar are only at 1 percent, there is concern that rate impacts

---

[41] See for example "Good Process" letter to Travis Kavulla, signed by 32 consumer, low-income, environmental and technology-specific advocates, June 23, 2016, available at http://blogs.edf.org/energyexchange/files/2016/06/Good-Rate-Design-Process-Letter-to-NARUC.pdf

[42] Such policies could include solar programs targeted to low-income individuals, reductions in solar generation credits, reductions in solar carve-out targets, or rate design options such as time-of-use rates or minimum bills. It is also important to understand how rate impacts may change over time. For example, short-term rate increases may be followed by long-term rate decreases. In such cases the mitigating policies should be chosen carefully to avoid losing the long-term rate reduction benefits.

will grow large in the near future under current net metering practices.

Step 2—Articulate Existing Regulatory Policies: The hypothetical jurisdiction currently has full net metering, i.e., residential solar customers are compensated at the hypothetical utility's variable rate of $0.14 per kilowatt-hour, but solar customers are also subject to a non-bypassable fixed charge of $5 per month. Solar customers do not receive any other incentives other than the current federal investment tax credit of 30 percent.

Step 3—Identify Policies that Warrant Evaluation: The jurisdiction wishes to continue net metering, but is considering changes to its current flat rate design, which will impact the magnitude of net metering credits. Alternatives being considered include time-of-use rates and demand charges. A time-of-use rate sets different energy rates for different periods of the day (e.g., off-peak, peak, and shoulder periods).

A demand charge reduces the energy charge but adds a charge based on the maximum amount of energy used during the month during any one period (typically measured on an hourly or 15-minute basis). By changing the energy rate, a demand charge impacts the degree to which solar customers can reduce their bills through solar generation, and thereby also affects the degree of cost-shifting.

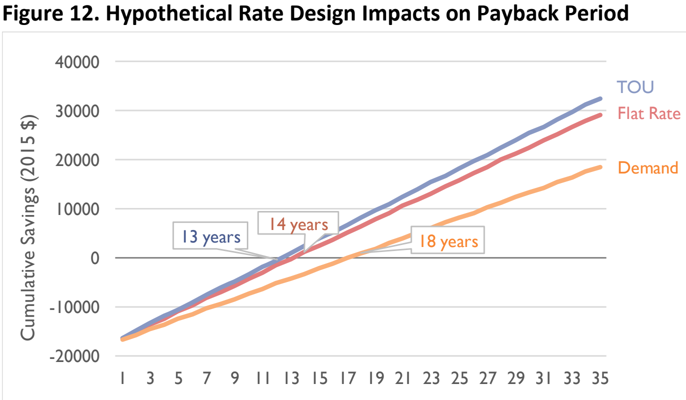
The rate design alternatives analyzed in this example are summarized in the table below, and were developed to be revenue neutral based on a hypothetical jurisdiction's customer usage patterns. (Further details are provided in Appendix B: Modeling Assumptions).

Table 5. Rate Design Policy Options Analyzed

Policy	Rate Design
Flat Rate	$0.14/kWh $5 fixed charge
TOU	$0.155/kWh Peak (9 am - 8:59 pm) $0.110/kWh Off-peak (9 pm – 8:59 am) $5 fixed charge
Demand Charge	$0.11/kWh $10/kW (based on maximum hour of month) $5 fixed charge

Step 4—Analyze Customer Adoption: As shown in the Figure 12 below, moving distributed solar customers from the flat rate to the TOU rate results in a decrease in the payback period from 14 years to 13 years, while a demand charge increases the payback period to 18 years.

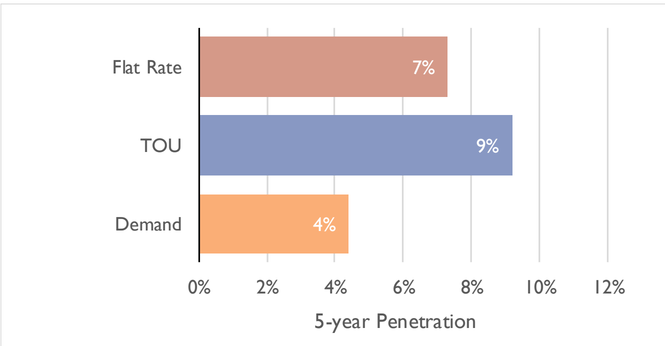
Figure 12. Hypothetical Rate Design Impacts on Payback Period



Using these payback periods and NREL's market penetration curves, five-year penetration rates can be estimated. We note that the payback periods assumed here are based on generic market penetration curves and may not reflect a jurisdiction's actual experience.[43]

Because of its shorter payback period, the TOU rate has the highest estimated five-year penetration rate, resulting in 9 percent of residential customers adopting distributed solar. Under the flat rate, penetration reaches 7 percent of residential customers, while under the demand charge, the percent of residential customers adopting solar reaches only 4 percent after five years. These estimated five-year penetration rates are shown in Figure 13.

Figure 13. Hypothetical 5-Year Penetration Rates



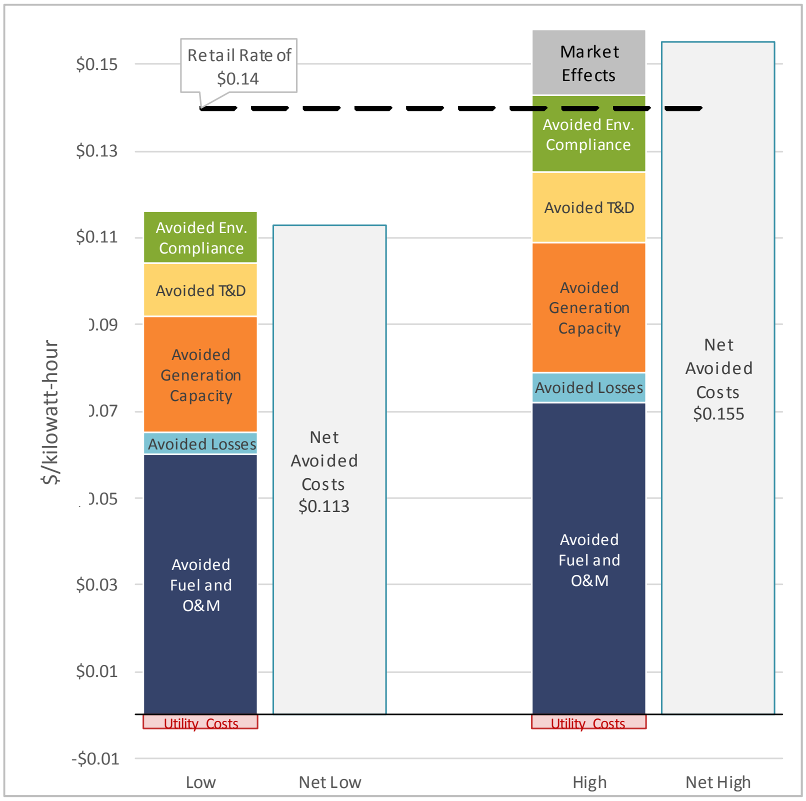
Step 5—Evaluate Cost Effectiveness: The avoided costs associated with distributed solar can vary significantly from jurisdiction to jurisdiction, and may change over time. For illustrative purposes, we discuss the results of two hypothetical avoided cost scenarios, one with net avoided utility system costs higher than the current retail rate of $0.14 per kilowatt-hour, and the other with net avoided costs that are lower than the retail rate, as shown in Figure 14 below.[44]

[43] We recommend that each jurisdiction conduct its own analysis of likely market penetration, and also consider the effect of alternative solar financing models (such as third-party leases). Further, we reiterate that the Bass Diffusion Model described in Section 3 does not account for the affordability of a technology. As the price of solar declines, customer adoption may surpass prior estimates.

[44] These avoided cost assumptions do not include any societal benefits or participant benefits. The environmental benefits that are included are those that would be incurred by the utility to comply with environmental regulations (such as NO_X, SO_X, and the Clean Power Plan). We have also subtracted out a small amount of utility costs (administrative or integration costs) to arrive at the net avoided costs. The magnitude of these costs and benefits is likely to change at higher penetrations, and thus must be re-evaluated frequently.

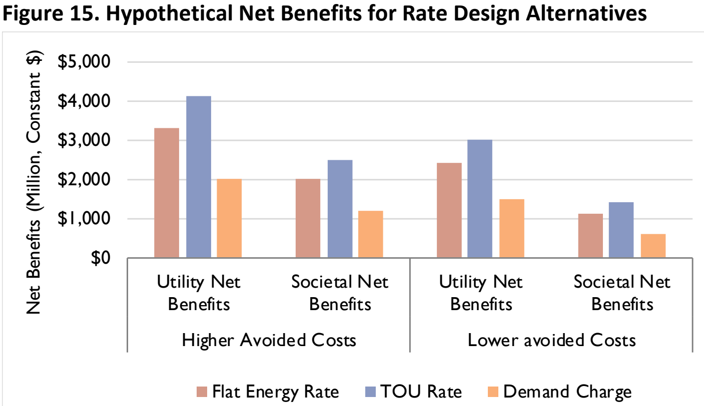
Cost-effectiveness results are presented in Figure 15 for the Utility Cost Test and the Societal Cost Test. Under both higher and lower avoided cost assumptions, each rate design analyzed exhibits positive net benefits. As discussed above, the Utility Cost Test is expected to result in positive net benefits, since the host customer's cost of installing a solar system is not included in the test. The Societal Cost Test may or may not result in positive net benefits, depending on the magnitude of any utility system or societal benefits (such as avoided environmental externalities.)[45]

Figure 14. Hypothetical Low and High Avoided Costs



The greatest net benefits are associated with the TOU rate, largely because the TOU rate results in the highest levels of solar adoption. The lowest net benefits are associated with the demand charge, which has relatively low customer adoption levels.

Figure 15. Hypothetical Net Benefits for Rate Design Alternatives



Step 6—Analyze Cost-Shifting: Bill impacts for non-solar customers are shown in Figure 16. All rate designs result in lower bills for non-solar customers in the scenario with higher avoided costs. These lower bills are shown as negative numbers in the graph and indicate that solar customers are providing a

45 In this report, for illustrative purposes, the Societal Cost Test includes a relatively low value of $0.01 per kWh in hypothetical avoided environmental externality benefits.

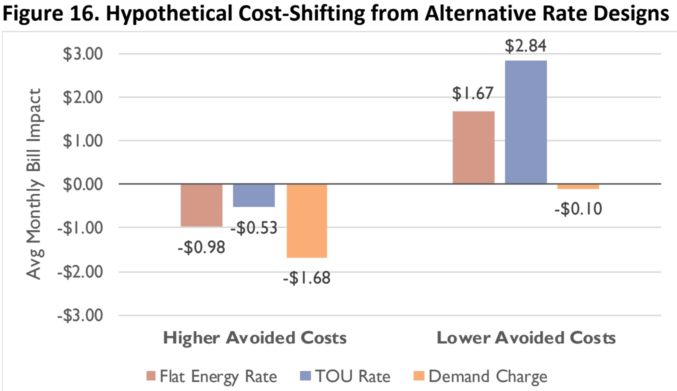
net benefit to both the system and to non-solar customers.) In the scenario with lower avoided costs, bills for non-solar customers are expected to increase for the flat rate and the TOU rate.

The results of lower bills for non-solar customers is expected under the higher avoided cost scenario, as the average avoided costs slightly exceed the retail rate. When avoided costs exceed the value of the credits received by solar customers, the reductions in utility costs offsets any rate increase that would occur due to lost revenues.

Under the lower avoided cost scenario, bill increases are expected because the average avoided costs are less than the bill credits received by solar customers under the flat rate and the TOU rate. The flat rate credit of $0.14 per kilowatt-hour exceeds the average avoided cost of $0.113 per kilowatt-hour, while the time-of-use rates and the peak time period definition (9 am – 9 pm) result in solar generation being compensated primarily at $0.155 per kilowatt-hour. Bill increases under the TOU rate are compounded by the fact that the TOU rate incentivizes greater solar adoption than under the flat rate, leading to higher overall penetration levels.

In the case of the demand charge, the compensation rate for solar customers is relatively low, only just slightly exceeding the lower avoided cost level. Further, solar generation generally does not reduce a solar customer's billed demand significantly, resulting in solar customers paying a similar demand charge as non-solar customers. Because the demand charge reduces solar customers' bill savings, penetration remains relatively low. For these reasons, cost-shifting from solar customers to non-solar customers does not occur under the demand charge (and in fact costs are being shifted in the other direction, from non-solar customers to solar customers).

Figure 16. Hypothetical Cost-Shifting from Alternative Rate Designs



Step 7—Assess Policy Options: The results of these alternative rate design policies are summarized in the tables below, which provide the opportunity to compare the net benefits to any cost-shifting impacts.

For example, assuming the higher avoided costs, the TOU rate results in the lowest bill reductions for non-solar customers. However, the TOU rate results in the highest net benefits, totaling more than $4 billion under the Utility Cost Test, and $2.5 billion under the Societal Cost Test. In contrast, the demand charge results in the greatest bill reductions, but the lowest net benefits and the lowest levels of solar penetration. The reason that the demand charge results in the greatest bill reductions is that costs are being shifted from non-solar customers to solar customers. In other words, solar customers are reducing system costs more than the value of their bill credits, under both the high and low avoided cost scenarios. Due to the relatively low penetration of 4 percent, however, the net benefits to the utility system are not as high as they would be under the flat rate or the TOU rate.

Table 6. Summary of Hypothetical Alternative Rate Design Policies—High Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Flat Rate	14	7%	$3,300	$1,800	$2,000	-$0.98	-0.7%
TOU (9 am – 9 pm)	13	9%	$4,100	$2,200	$2,500	-$0.53	-0.4%
Demand	18	4%	$2,000	$1,000	$1,200	-$1.68	-1.2%

Under the assumption of low avoided costs, the trade-off among policies becomes more pronounced. In this case, both the flat rate and the TOU rate result in bill increases for non-solar customers. (See Table 7, below.) However, these two rates also provide the greatest net benefits to the utility system and society. Decision-makers and stakeholders must then determine the appropriate trade-offs between bill decreases and overall net benefits. (Note that there are many ways that a TOU rate can be designed, as explored more in the following chapter.)

Table 7. Summary of Hypothetical Alternative Rate Design Policies—Low Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Flat Rate	14	7%	$2,400	$900	$1,100	$1.67	1.1%
TOU (9 am – 9 pm)	13	9%	$3,000	$1,100	$1,400	$2.84	2.0%
Demand	18	4%	$1,500	$500	$600	-$0.10	-0.1%

These results can be used by decision-makers and other stakeholders to compare distributed solar policies, and ideally to choose those that balance the potential rate impacts with cost-effectiveness and the state's energy policy goals. Further, the results can be used to establish appropriate penetration thresholds for future review of solar policies.

Decision-makers and stakeholders may differ in their choice of preferred policy options, but the framework described in this report will serve to make deliberations transparent and well informed.

7. FURTHER EXAMPLES

To illustrate how various policies may affect solar penetration, cost-effectiveness, and cost-shifting, we have modeled several additional scenarios, using the hypothetical low and high avoided cost estimates introduced above. Each jurisdiction has its own unique characteristics in terms of avoided costs, customer usage patterns, solar output, rate structures, and incentives for solar PV. For this reason, the results below cannot be assumed to apply broadly to all jurisdictions, although the general direction of the results may hold in many parts of the country.

7.1. TOU Rate Sensitivity

Time-of-use rates can be designed in many ways. They can consist of long peak periods (such as the 9 am–9 pm example above), or the peak period can be narrow. The differential between the peak and off-peak rate also plays a critical role in determining the magnitude of bill credits received by solar customers. TOU rates can provide more efficient price signals than flat rates if they are designed so that the prices associated with each period reflects the relative cost of providing electricity during those hours. Prices are typically highest during periods of high demand, when the most expensive generators must be used to provide power.

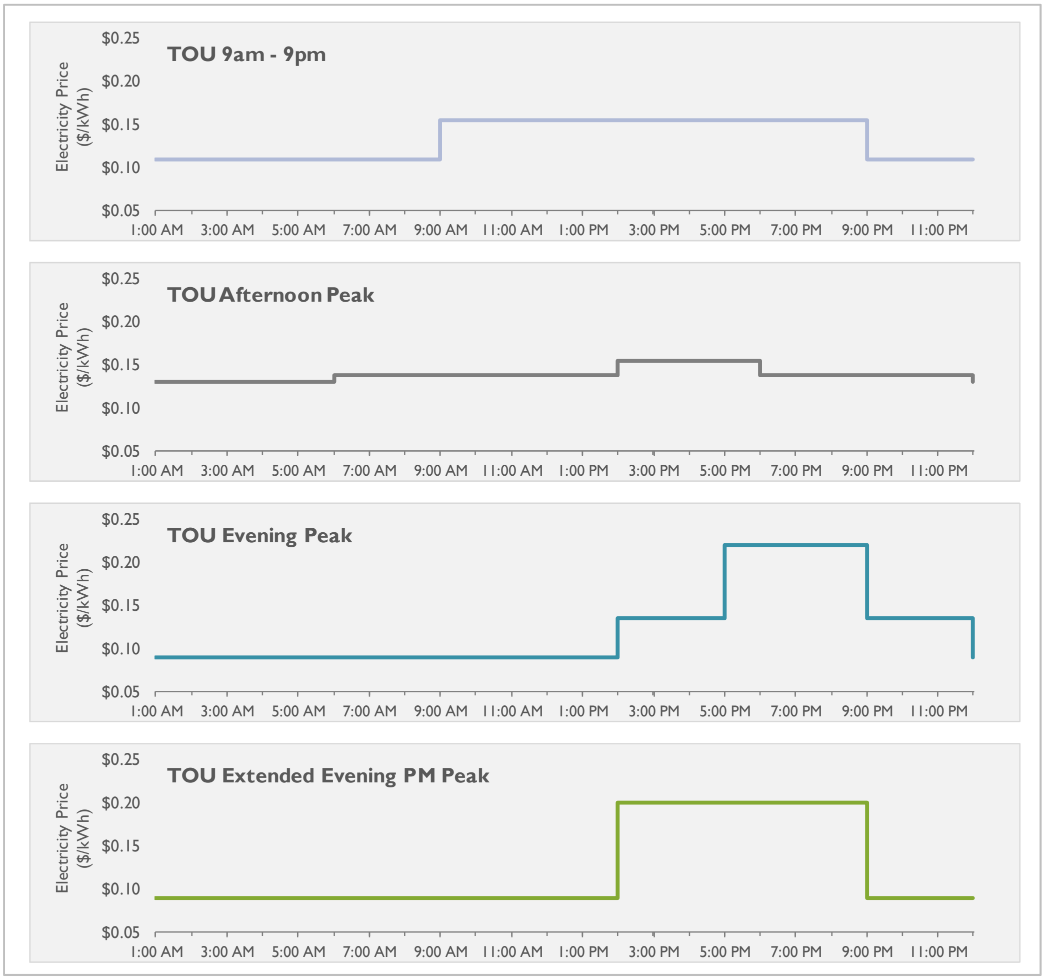
Step 3—Identify Policies that Warrant Evaluation: To continue our example from above, suppose that the hypothetical jurisdiction wishes to examine the range of impacts that the design of TOU rates can have on solar penetration, cost-effectiveness, and cost-shifting. To do so, the jurisdiction conducted a sensitivity analysis using several variations of a TOU rate, shown in the table below.

Table 8. TOU Rate Alternatives Analyzed

TOU Rate Name	Hours	Rate Design
TOU Afternoon Peak	Peak: 2:00 pm – 5:59 pm Shoulder: 6:00 am – 1:59 pm, 6:00 pm – 11:59 pm Off-Peak: 12:00 am – 5:59 am	Peak: $0.155 Shoulder: $0.138 Off-Peak: $0.130
TOU Evening Peak	Peak: 5:00 pm – 8:59 pm Shoulder: 2:00 pm – 4:59 pm, 9 pm – 11:59 pm Off-Peak: 12:00 am – 1:59 pm	Peak: $0.220 Shoulder: $0.135 Off-Peak: $0.090
TOU Extended PM Peak	Peak: 2:00 pm – 8:59 pm Off-Peak: 9:00 pm – 1:59 pm	Peak: $0.200 Off-Peak: $0.090

These TOU options are illustrated in the figure below:

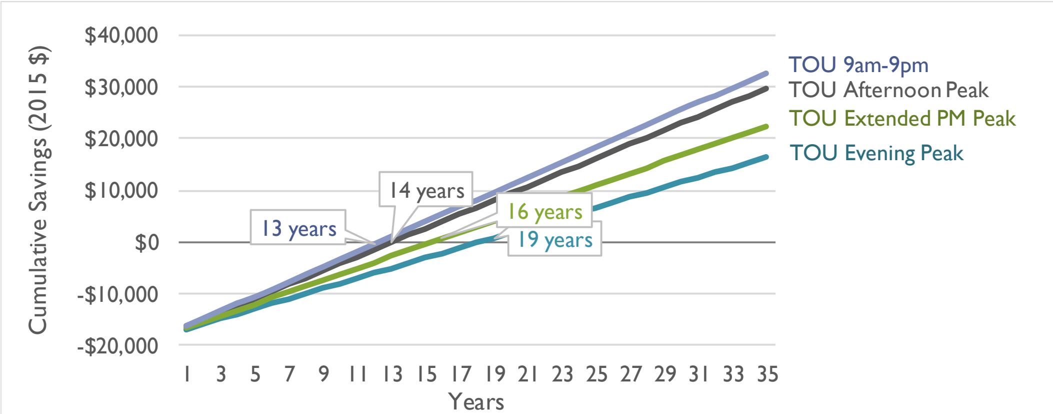
Figure 17. TOU Rates Modeled



Step 4—Analyze Customer Adoption: The payback periods shown below demonstrate how changes to TOU rate peak/shoulder/off-peak periods and their associated prices can significantly impact distributed solar economics. For comparison purposes, the TOU rate from Section 6 (with a peak period from 9 am – 9 pm) is also included.

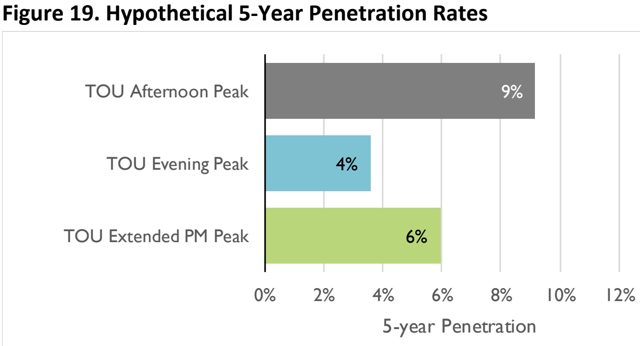
The TOU rate from the previous example (9 am – 9 pm) has a payback period of 13 years, while the three new TOU rates analyzed have payback periods that range from 14 to 19 years. The TOU Extended Evening Peak (with a peak from 5 pm – 9 pm) has the longest payback period, as it results in net metered solar customers being credited for their generation primarily at the off-peak rate or shoulder rates, since the peak period does not begin until solar generation is waning.

Figure 18. Hypothetical Payback Periods for TOU Rate Alternatives



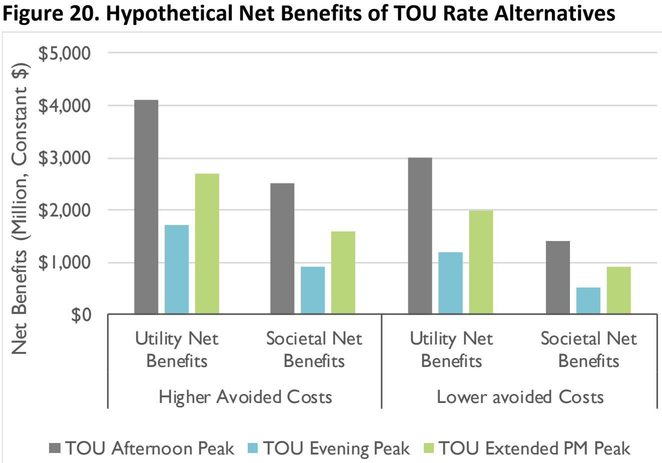
The five-year penetration levels associated with the TOU Afternoon Peak design is 9 percent, while the penetration level for a TOU Extended PM Peak design is 6 percent, while the TOU Evening Peak results in a five-year penetration level of only 4 percent. These penetrations are shown in Figure 19.

Figure 19. Hypothetical 5-Year Penetration Rates



Step 5—Evaluate Cost-Effectiveness: As in the previous chapter, the cost-effectiveness results are presented under both higher and lower avoided cost estimates. Again, all rate options exhibit positive net benefits, with the greatest net benefits associated with the rate with the highest penetration of solar (the TOU Afternoon Peak design). These results are shown in Figure 20 below.

Figure 20. Hypothetical Net Benefits of TOU Rate Alternatives

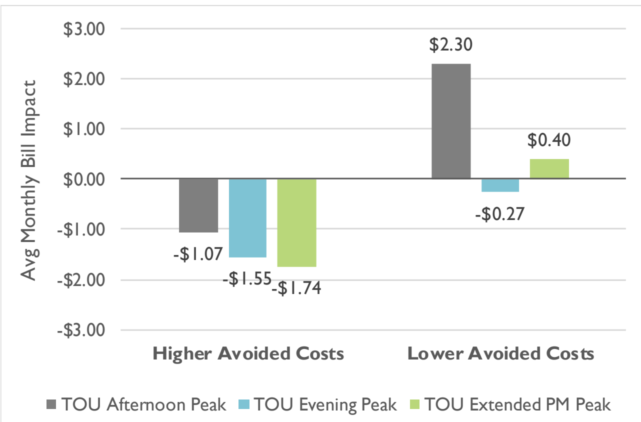


Step 6—Analyze Cost Shifting: Bill impacts for non-solar customers vary significantly by TOU rate design, as shown in Figure 21. Under the higher avoided cost scenario, all TOU rates result in bill reductions for non-solar customers, with the greatest bill reductions stemming from the Extended PM Peak design. Under the lower avoided cost scenario, the TOU rate with an evening peak period still results in bill reductions for non-solar customers, since the average bill credit for solar generation is less than the average avoided cost.

In contrast, the bill increase associated with the TOU Afternoon Peak rate is more than $2 per month, due to the fact that this rate aligns well with solar generation and results in the highest penetration levels. Thus a large portion of solar generation is compensated at a peak period rate that exceeds the levelized avoided cost value under the lower avoided cost scenario.

The Extended PM Peak rate (with a peak from 2 pm to 9 pm) results in much lower bill increases ($0.40 per month), while still achieving moderate five-year penetration levels of 6 percent.

Figure 21. Hypothetical Bill Impacts of TOU Rate Alternatives



Step 7—Assess Policy Options: The overall hypothetical impacts of the TOU rates analyzed are summarized in the tables below.

Table 9. Summary of Hypothetical TOU Rate Impacts – High Avoided Cost

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
TOU Peak 2pm-6pm	13	9%	$4,100	$2,200	$2,500	-$1.07	-0.7%
TOU Peak 5pm-9pm	14	7%	$1,700	$800	$900	-$1.55	-1.1%
TOU Peak 2pm-9pm	16	6%	$2,700	$1,400	$1,600	-$1.74	-1.2%

Table 10. Summary of Hypothetical TOU Rate Impacts – Low Avoided Cost

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
TOU Peak 2pm-6pm	13	9%	$3,000	$1,100	$1,400	$2.30	1.6%
TOU Peak 5pm-9pm	14	7%	$1,200	$400	$500	-$0.27	-0.2%
TOU Peak 2pm-9pm	16	6%	$2,000	$700	$900	$0.40	0.3%

7.2. Fixed Charges and Minimum Bills

In recent years, many utilities have proposed to increase fixed charges for residential customers, in some cases substantially (Whited, Woolf, and Daniel 2016). By increasing the fixed portion of the bill, fixed charges reduce the energy rate, thereby also reducing bill credits for net metered customers. As an alternative to increasing the fixed charge, some jurisdictions have adopted a minimum bill. Minimum bills only take effect if a customer's bill would fall below the minimum amount; otherwise the minimum bill does not apply. Unlike a fixed charge, a minimum bill does not reduce the energy rate, thereby enabling net metered customers to receive the same credit per kilowatt-hour after they have paid the minimum bill.

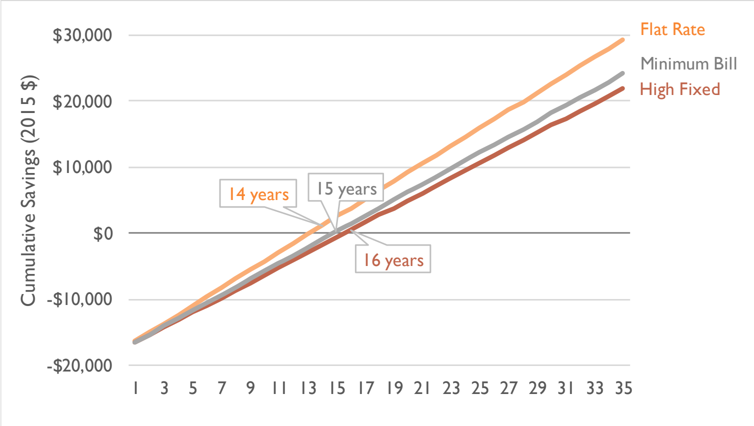
Step 3—Identify Policies that Warrant Evaluation: This example explores the impacts of increasing the fixed charge to $25 per month or setting a minimum bill at $25 per month for the hypothetical jurisdiction. All rates are designed to be revenue neutral.

Table 11. Flat Rate, Higher Fixed Charge, and Minimum Bill Designs Analyzed

Policy	Rate Design
Flat Rate	Flat energy charge of $0.14 Fixed charge of $5
Higher Fixed	Flat energy charge of $0.12 Fixed charge of $25
Minimum Bill	Flat energy charge of $0.145 Minimum bill of $25 No fixed charge

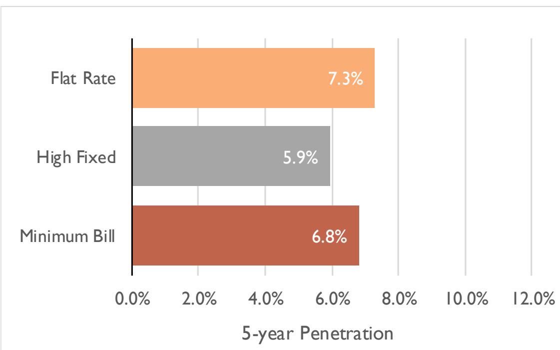
Step 4—Analyze Customer Adoption: Both the minimum bill and the higher fixed charge increase the payback period for net metered customers. Under the minimum bill, the payback period increases from 14 years to 15 years, while the higher fixed charge extends the payback period to 16 years.

Figure 22. Hypothetical Payback Periods for Flat Rate, Higher Fixed Charge, and Minimum Bill



Although the minimum bill increases the payback period by a year, it is not enough to significantly alter the five-year penetration rate. Under the minimum bill, the five-year penetration declines only slightly from 7.3 percent to 6.8 percent.[46] Under the high fixed charge, penetration declines to 5.9 percent.

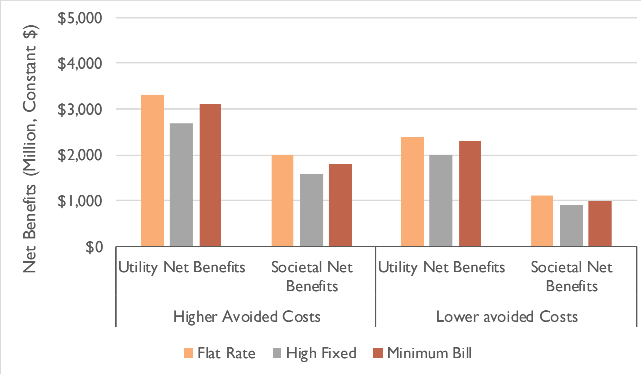
Figure 23. Hypothetical 5-Year Penetration Rates



Step 5—Evaluate Cost-Effectiveness: All three rate designs are cost-effective, but the flat rate exhibits the highest net benefits, followed by the minimum bill, as shown in Figure 24. This is in part due to the flat rate and minimum bills result in higher penetrations of solar than the high fixed charge.

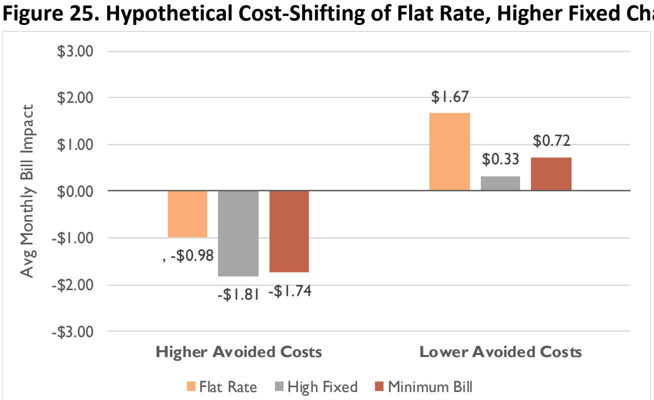
[46] Reported values are rounded.

Figure 24. Hypothetical Net Benefits of Flat Rate, Higher Fixed Charge, and Minimum Bill



Step 6—Analyze Cost-Shifting: As expected, by increasing the amount that solar customers must pay, the higher fixed charge and the minimum bill reduce potential negative impacts on non-solar customers. In the higher avoided cost scenario, the fixed charge and minimum bill result in nearly identical bill reductions for non-solar customers, despite the minimum bill enabling greater solar penetration. In the lower avoided cost scenario, the fixed charge reduces the monthly bill increase from $1.67 under the flat rate to only $0.33. The minimum bill also significantly reduces any bill increases for non-solar customers, reducing the average monthly bill increase to $0.72.

Figure 25. Hypothetical Cost-Shifting of Flat Rate, Higher Fixed Charge, and Minimum Bill



The combined results are presented in tabular format in the tables below.

Table 12. Hypothetical Summary of Alternative Compensation Results—High Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Flat Rate	14	7%	$3,300	$1,800	$2,000	-$0.98	-0.7%
High Fixed Charge	16	6%	$2,700	$1,400	$1,600	-$1.81	-1.2%
Minimum Bill	15	7%	$3,100	$1,600	$1,800	-$1.74	-1.2%

Table 13. Hypothetical Summary of Alternative Compensation Results—Low Avoided Costs

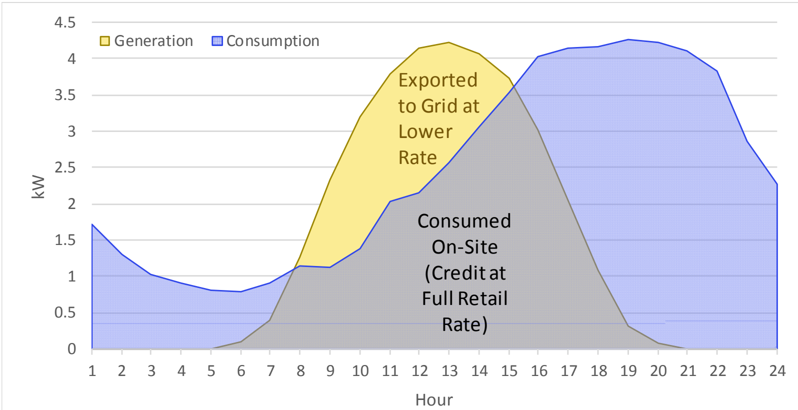
	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Flat Rate	14	7%	$2,400	$900	$1,100	$1.67	1.1%
High Fixed Charge	16	6%	$2,000	$700	$900	$0.33	0.2%
Minimum Bill	15	7%	$2,300	$800	$1,000	$0.72	0.5%

7.3. Alternative Compensation Mechanisms

Some jurisdictions are considering moving from traditional net metering (which provides one-to-one monthly bill credits to solar customers to offset their consumption) to alternative forms of netting. One form consists of netting net generation against consumption on a near-instantaneous basis, rather than at the end of the month. Solar generation that is not immediately consumed on-site is exported to the grid at a reduced rate. A similar concept is known as net billing, which still uses a monthly timeframe for netting, but compensates monthly excess generation at a reduced rate.

Instantaneous netting and net billing are therefore nearly identical, except that they conduct the netting over different time frames. Under net billing, if a customer generated 800 kWh and consumed 800 kWh over the course of the month, all generation would be credited at the retail rate. Under instantaneous netting, a customer would receive the full retail rate for much less of their generation if their load and generation profiles did not fully align. An example of this situation is shown in Figure 26, below, where the customer receives full compensation for only 70 percent of his or her generation on a particular day.

Figure 26. Example Compensation Under Instantaneous Netting



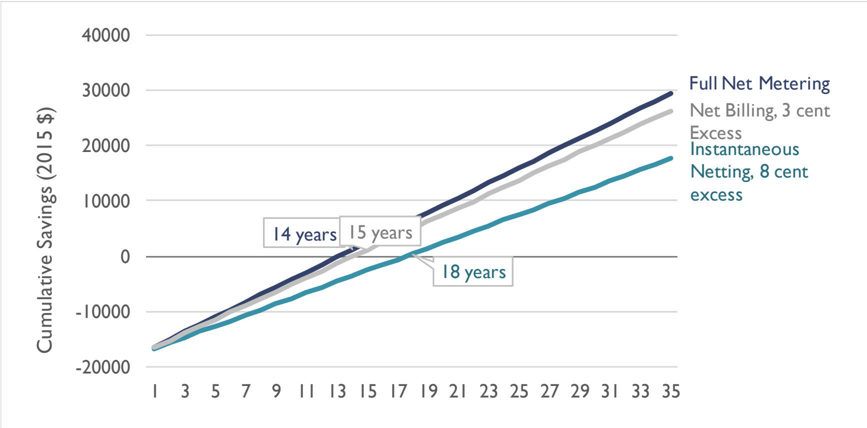
Step 3—Identify Policies that Warrant Evaluation: Suppose the hypothetical jurisdiction wishes to examine the impact of other compensation mechanisms, such as instantaneous net metering with reduced payment for any generation exported to the grid (e.g., $0.08 per kilowatt-hour of generation not consumed immediately at the customer's site), and net billing with reduced payment for monthly excess generation (e.g., $0.03 per kilowatt-hour for any generation that does not offset consumption when netting occurs at the end of the month.) These policies are summarized in the table below.

Table 14. Alternative Compensation Mechanisms Analyzed

Policy	Credit for Behind-the-Meter Generation	Credit for Generation Exported to Grid	Credit for Monthly Excess Generation
Full Net Metering	Full retail rate ($0.14)	Full retail rate ($0.14)	Full retail rate ($0.14)
Instantaneous Netting	Full retail rate ($0.14)	$0.08 for any generation not consumed immediately on-site	$0.08
Net Billing	Full retail rate ($0.14)	Full retail rate ($0.14) until generation exceeds consumption	$0.03

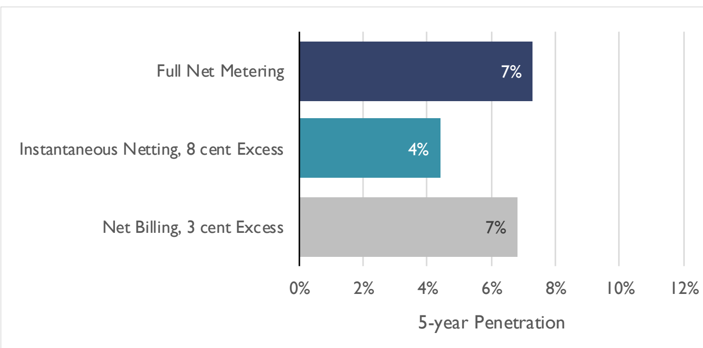
Step 4—Analyze Customer Adoption: A comparison of the payback periods associated with each of these options might reveal that the current full net metering arrangement has an estimated payback period of 14 years, a net billing arrangement with $0.03/kWh for excess compensation might only lengthen that payback period to 15 years, and instantaneous netting with $0.08/kWh for generation pushed onto the grid would extend the payback period to 18 years. This demonstrates the degree to which instantaneous netting can erode a solar customer's bill savings, even when the credit for exports is much higher than the monthly excess rate under net billing.

Figure 27. Hypothetical Payback Periods for Alternative Compensation Mechanisms



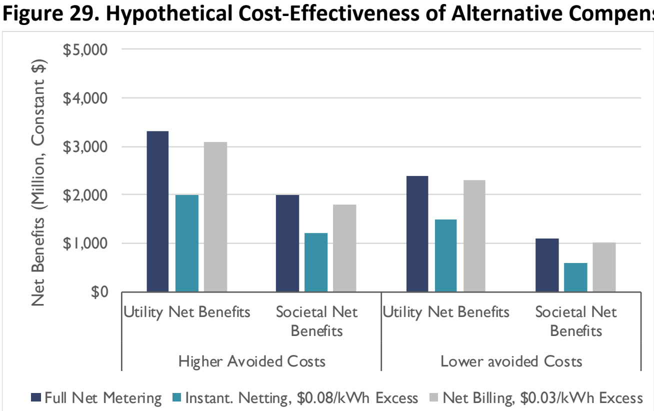
Based on market penetration curves, these payback periods would be expected to yield a five-year penetration rate of 7 percent under full net metering and under net billing, but only 4 percent under instantaneous netting.

Figure 28. Hypothetical 5-Year Penetration Rates



Step 5—Evaluate Cost-Effectiveness: Under both higher and lower avoided costs, each compensation policy is shown to be cost-effective, as demonstrated by positive net benefits (see Figure 29). However, the net benefits are highest for full net metering and lowest for instantaneous netting.

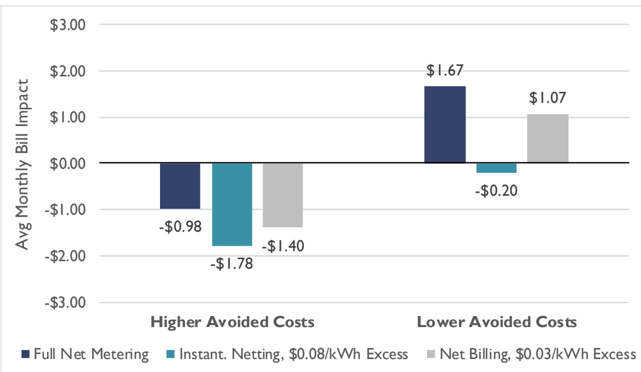
Figure 29. Hypothetical Cost-Effectiveness of Alternative Compensation Mechanisms



Step 6—Analyze Cost-Shifting: The extent to which distributed solar increases or decreases bills for non-solar customers is highly dependent upon three factors: the bill credits that the solar customer receives, the avoided costs to the utility system, and the percentage of customers that install distributed solar. We have again used both high and low estimates of avoided costs to illustrate the potential for cost-shifting at a hypothetical utility. As shown in the graph below, full net metering provides the greatest compensation to solar customers, thereby resulting in the highest penetration levels. Under the higher avoided costs scenario, this is not problematic, as the avoided costs outweigh the net metering credit (the retail rate), resulting in bill decreases of approximately $1 per month on average for non-solar customers. However, under the lower avoided cost scenario, bill increases of $1.67 per month can be expected for non-solar customers under full net metering.

Under the instantaneous netting scenario, solar penetration remains relatively low, at only 4 percent of residential customers. However, the avoided costs greatly exceed the bill credits in the higher avoided cost scenario, leading to bill reductions under both scenarios.

Figure 30. Hypothetical Penetration Levels and Bill Impacts of Alternative Compensation Mechanisms



Step 7—Assess Policy Options: Table 15 tables below provide a summary of the results of the alternative compensation mechanisms analyzed.

Table 15. Hypothetical Summary of Alternative Compensation Results—High Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	*%*
Full Net Metering	14	7%	$3,300	$1,800	$2,000	-$0.98	-0.7%
Instantaneous Netting, 8 cent Excess	18	4%	$2,000	$1,000	$1,200	-$1.78	-1.2%
Net Billing, 3 cent Excess	15	7%	$3,100	$1,600	$1,800	-$1.40	-1.0%

Table 16. Hypothetical Summary of Alternative Compensation Results—Low Avoided Costs

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	TRC Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	%	*2015 $ Million*	*2015 $ Million*	*2015 $ Million*	*2015 $/mo*	%
Full Net Metering	14	7%	$2,400	$900	$1,100	$1.67	1.1%
Instantaneous Netting, 8 cent Excess	18	4%	$1,500	$500	$600	-$0.20	-0.1%
Net Billing, 3 cent Excess	15	7%	$2,300	$800	$1,000	$1.07	0.7%

7.4. Conclusions Regarding Modeling Results

The illustrations above will not necessarily reflect the reality of any particular policy in any particular place. These examples are provided simply to illustrate the types of analyses that should be used to inform policy discussions. Nonetheless, based on our review of studies performed to date, as well as the illustrations in this report, the numbers suggest several general conclusions.

- First, payback period results are highly sensitive to the retail rate in place, as well as system cost and size assumptions. Increased fixed charges and demand charges can dramatically increase payback periods.

- Second, cost-effectiveness results are very sensitive to avoided cost estimates. Under the Utility Cost Test, distributed solar appears highly cost effective, while under the Total Resource Cost Test distributed solar is much less cost effective. However, the TRC Test does not fully account for participant benefits (bill reductions). Under the Societal Cost Test, distributed solar is often, but not always, cost effective. The Societal Cost Test helps indicate the extent to which distributed solar will meet certain state policy goals.

- Third, cost-shifting results are very sensitive to avoided cost estimates. In general, the extent of cost-shifting will depend upon the relationship between the net avoided costs[47] to the utility system and the credit that the solar customer receives. At low penetrations, cost-shifting is likely to be minimal.

[47] Net avoided costs consist of both the benefits (avoided costs) to the utility system, as well as any increase in system costs caused by distributed solar.

8. SCOPE OF THIS REPORT AND FURTHER RESEARCH

8.1. Scope and Limitations of this Report

Developing balanced distributed solar policies requires consideration of many complex economic, technical, and policy issues. The economic framework proposed in this report will help provide important information for sorting through many of these complex issues, but it is not intended to provide an answer to every question.

Each jurisdiction will need to consider several issues, in addition to those addressed here, to ensure that its distributed solar policies will meet its goals and be in the public interest. For example, decision-makers and utilities should be mindful of the technical limitations of installing increasing amounts of distributed solar on the distribution grid, and the costs of doing so. As another example, decision-makers and utilities should be mindful that average avoided cost values obscure the locational variation of costs and benefits. These important considerations are beyond the scope of this study.

Actual results are likely to be very sensitive to specific conditions applicable to the utility territory in question, particularly avoided costs.

In addition, the illustrative analyses presented in this report are not intended to provide an indication of the results that will be experienced for any particular state or utility. The actual results are likely to be very sensitive to the specific conditions applicable to the utility territory in question. This is particularly true with regard to estimates about avoided costs, but is also true with regard to retail rates and customer load profiles. Thus, the illustrative analyses presented in this report should not be used to draw specific conclusions about any one state or utility. It is essential that each state or utility apply the framework proposed here based upon local conditions and assumptions, using the best information that is available.

Further, the illustrative analyses in this report include some simplifying assumptions that could affect the analytical results. With regard to cost-effectiveness, the analysis does not account for variation in avoided costs due to the timing or location of distributed solar generation. The customer adoption rates and models currently available in the literature are based on limited research and may not reflect accurately project customer adoption rates for every jurisdiction. With regard to cost-shifting and rate impacts, our analysis does not account for the extent to which costs could be allocated differently across classes as a result of high penetrations of distributed solar. Ideally, state-specific and utility-specific analyses will be able to improve upon these simplifying assumptions over time.

Recommendations for Next Steps and Further Research

As demonstrated by the illustrative results above, the analyses recommended in this report are highly dependent upon good data. For this reason, we strongly recommend that regulators encourage collaborative and transparent processes for estimating the avoided costs of distributed solar resources.

While there are many value-of-solar studies available today, there also remains considerable debate over avoided cost calculations and assumptions. Regulators should encourage utilities and other stakeholders to develop avoided cost estimates in a collaborative and transparent fashion. The six New

England states use this approach for developing avoided costs of energy efficiency resources, and a similar approach could be used to develop avoided costs for distributed solar resources.

In particular, we recommend that a collaborative approach be taken to develop standard avoided cost methodologies and data collection processes. Some of the most difficult avoided cost categories to estimate are:

Regulators should encourage utilities and other stakeholders to develop avoided cost estimates in a collaborative and transparent fashion.

- Avoided transmission and distribution costs of distributed solar resources.
- Locational value of distributed solar resources.
- Utility costs of integrating and supporting distributed solar generation on the distribution grid.

In addition, there are several avenues of further research that would be especially useful for states and utilities seeking to answer key questions in designing balanced distributed solar policies. These include:

- Customer adoption curves for distributed solar resources, and how such adoption curves vary by location or demographics (including income levels), and how third-party leases or subsidized loans impact the adoption curves.
- Analyses of the customer adoption, the cost-effectiveness, and the cost-shifting implications of community solar projects.
- Best practices for incorporating distributed solar resources into distribution system planning processes in order to reap the greatest net benefits.

9. Overall Conclusions

In setting distributed solar policies, utility regulators and state policymakers should seek to strike a balance between ensuring that cost-effective clean energy resources continue to be developed, and avoiding unreasonable rate and bill impacts for non-solar customers. Yet without a full understanding of how policy changes may affect both solar and non-solar customers, decision-makers risk implementing policies that are inappropriate for the jurisdiction's context.

While there are many analytical assessments of the likely cost-effectiveness of distributed solar resources, there are few analytical assessments of the extent to which distributed solar might result in cost-shifting to non-solar customers—even though this question is of great concern to stakeholders in every jurisdiction. Further, there are few analytical assessments of the extent to which different distributed solar policies are likely to impact the growth of distributed solar resources. Yet this is a central question that should be addressed when evaluating distributed solar policies.

To assist decision-makers in evaluating distributed solar policy options comprehensively and concretely, this report outlines a framework for evaluating distributed solar policies, which is summarized in the table below:

Table 17. Summary of Framework for Addressing Key Solar Policy Questions

Question	Analysis	Tools
Will the policy impact the adoption of distributed solar?	Development of distributed solar	Payback period analysis Penetration analysis
Will the policy result in net benefits to the utility system, to customers, and to society?	Cost-effectiveness	Utility Cost Test Societal Cost Test Total Resource Cost Test
To what extent does the policy mitigate or exacerbate any cost-shifting to non-solar customers?	Cost-shifting	Rate impact analysis Bill impact analysis

Using the results of the analyses presented above, decision-makers can review the projected impacts of various policy options to determine what course of action is in the public interest. Appropriate consideration of all relevant impacts will help decision-makers to avoid implementing policies that have unintended consequences or that fail to achieve policy goals. The analysis results can also help to determine the point at which certain distributed solar policies should be reevaluated or modified. It is critical, however, that the analyses be based on accurate inputs, particularly for avoided costs.

Given that each jurisdiction has its own policy goals and unique context, the ultimate policy decision reached by decision-makers may be different in each jurisdiction, even when based on the same analytical results. Nonetheless, the framework articulated above will provide decision-makers with the ability to balance protection of customers with achieving overarching policy objectives in a transparent, data-driven process.

10. References

Barbose, Galen. 2016. "U.S. Renewables Portfolio Standards 2016 Annual Status Report." Lawrence Berkeley National Laboratory, April. rps.lbl.gov.

Barbose, Galen, and Naim Darghouth. 2016. "Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States." LBNL-1006036. *Tracking the Sun*. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/tracking-sun-ix-installed-price.

Bass, Frank. 1969. "A New Product Growth for Model Consumer Durables." *Management Science* 15 (5).

Beach, R. Thomas, and Patrick G. McGuire. 2013. "The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina." https://c.ymcdn.com/sites/energync.site-ym.com/resource/resmgr/Resources_Page/NCSEA_benefitssolargen.pdf.

Bonbright, James. 1961. *Principles of Public Utility Rates*. New York: Columbia University Press.

California Public Utilities Commission. 2001. "California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects."

Chandrasekaran, Deepa, and Gerard Tellis. 2007. "A Critical Review of Marketing Research on Diffusion of New Products." In *Review of Marketing Research*, Volume 3:39–80. Emerald Group Publishing Limited. http://www.emeraldinsight.com/doi/abs/10.1108/S1548-6435%282007%290000003006.

City of Austin. 2016. "Value of Solar (Rider)." Accessed July 6. http://austinenergy.com/wps/wcm/connect/c6c8ad20-ee8f-4d89-be36-2d6f7433edbd/ResidentialSolar.pdf?MOD=AJPERES.

Consumer, low-income, environmental and technology-specific advocates. 2016. "Letter to Travis Kavulla, President of the National Association of Regulatory Utility Commissioners Regarding Good Process," June 23. http://blogs.edf.org/energyexchange/files/2016/06/Good-Rate-Design-Process-Letter-to-NARUC.pdf.

Gagnon, Pieter, Robert Margolis, Jennifer Melius, Caleb Phillips, and Ryan Elmore. 2016. "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment." NREL/TP-6A20-65298. National Renewable Energy Laboratory.

Gagnon, Pieter, and Ben Sigrin. 2016. "Distributed PV Adoption – Sensitivity to Market Factors." NREL Presentation, February. http://www.nrel.gov/docs/fy16osti/65984.pdf.

Hallock, Lindsey, and Rob Sargent. 2015. "Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society." Environment America Research & Policy Center; Frontier Group.

National Efficiency Screening Project (NESP). Forthcoming. "National Standard Practice Manual."

---------- 2014. "The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening." The National Efficiency Screening Project. http://www.synapse-energy.com/Downloads/SynapseReport.2014-03.0.Resource-Value-Framework.14-027.pdf.

National Renewable Energy Laboratory (NREL). 2016. "Distributed Generation Energy Technology Operations and Maintenance Costs." *National Renewable Energy Laboratory Energy Analysis*. February. http://www.nrel.gov/analysis/tech_cost_om_dg.html.

North Carolina Clean Energy Technology Center (NCCETC). 2016. "The 50 States of Solar: Q1 2016 Quarterly Report."

Norris, Benjamin L., Philip M. Gruenhagen, Robert C. Grace, Po-Yu Yuen, Richard Perez, and Karl R. Rabago. 2015. "Maine Distributed Solar Valuation Study." http://www.nrcm.org/wp-content/uploads/2015/03/MPUCValueofSolarReport.pdf.

Paidipati, J., L. Frantzis, H. Sawyer, and A. Kurrasch. 2008. "Rooftop Photovoltaics Market Penetration Scenarios." NREL/SR-581-42306. http://www.nrel.gov/docs/fy08osti/42306.pdf.

Perez, Richard, Benjamin L. Norris, and Thomas E. Hoff. 2012. "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania." Clean Power Research. http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

Public Utilities Commission of Hawaii. 2015. "Decision and Order 33258, Docket No. 2014-0192."

R.W. Beck, Inc. 2009. "Distributed Renewable Energy Operating Impacts and Valuation Study." Prepared for Arizona Public Service.

Rabago, Karl, Leslie Libby, Tim Harvey, Benjamin Norris, and Thomas Hoff. 2016. "Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator." Austin Energy and Clean Power Research. Accessed July 6. http://www.cleanpower.com/wp-content/uploads/090_DesigningAustinEnergysSolarTariff.pdf.

Sigrin, Ben, and Easan Drury. 2014. "Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics." In *AAAI Energy Market Prediction Symposium*. Washington, DC.

Sigrin, Ben, Michael Gleason, Robert Preus, Ian Baring-Gould, and Robert Margolis. 2016. "The Distributed Generation Market Demand Model (dGen): Documentation." NREL/TP-6A20-65231. NREL.

SREC Trade. 2016. "SREC Markets." http://www.srectrade.com/srec_markets/.

Stanton, Elizabeth A., Joseph Daniel, Tommy Vitolo, Pat Knight, David White, and Geoff Keith. 2014. "Net Metering in Mississippi Costs, Benefits, and Policy Considerations." Synapse Energy Economics, prepared for the Public Service Commission of Mississippi. http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

U.S. Department of Energy. 2016. "Residential Renewable Energy Tax Credit." *Energy.gov*. September. http://www.energy.gov/savings/residential-renewable-energy-tax-credit.

U.S. Energy Information Administration (EIA). 2004. "The Electricity Market Module of the National Energy Modeling Systems: Model Documentation Report." DOE/EIA-M068. Washington, DC: Department of Energy.

Whited, Melissa, Tim Woolf, and Joseph Daniel. 2016. "Caught in a Fix: The Problem with Fixed Charges for Electricity." Synapse Energy Economics, prepared for Consumers Union.

Woolf, Tim, Melissa Whited, Erin Malone, Tommy Vitolo, and Rick Hornby. 2014. "Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits." Synapse Energy Economics, prepared for the Advanced Energy Economy Institute.

Appendix A: Generic Discovery Requests for Assessing Distributed Solar Policies

This section contains sample discovery questions designed to assist stakeholders obtain the key pieces of information that are required for conducting the analyses recommended in this report.

Note that a "typical residential PV system" may vary across utilities. It is recommended that the term either be specifically defined for the utility or that the utility be asked to define what it considers to be a "typical residential PV system" with regard to the questions asked and answered herein.

It is expected that some costs and avoided costs are constant, others only occur in the first year, and still others will vary throughout the years. Also note that these costs or avoided costs may be a function of the total quantity of residential PV expected to be on the utility system in each future year.

System Information

All questions refer to customers in the utility system within the state/territory.

General

1. Please provide the number of residential customers.
2. Please provide the forecasted number of residential customers for each year of the study period.
3. Please provide the complete tariff or tariffs applicable to non-PV residential customers.

PV

4. Please provide the current number of residential PV customers.
5. Please provide the current solar PV nameplate capacity of residential PV on the utility system.
6. Please provide any studies or forecasts for the number of residential PV customers for each year of the study period.
7. Please provide any studies or forecasts for the total expected solar PV nameplate capacity of all the residential PV systems for each year of the study period.
8. Please provide the complete tariff or tariffs applicable to residential customers with interconnected PV systems.

Cost Information

General

9. To the extent that the utility has modeled a typical residential PV system for any cost or benefit calculations, please provide the detailed assumptions for the typical residential PV system, including

    a. Latitude and longitude;

    b. DC system size;

    c. Array tilt;

    d. Array azimuth;

    e. System loss percentage; and

    f. Inverter efficiency.

10. To the extent that the utility has modeled a typical residential PV system's hourly output for any of the cost or benefit calculations below, please provide the modeled hourly output data for that PV system. If not, please provide any rationale for not using the NREL PVWatts model.

Utility System Costs

11. Please provide any studies or forecasts of system interconnection costs borne by the utility. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

12. Please provide any studies or cost forecasts regarding costs to integrate additional PV in the utility's service territory. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If applicable, please distinguish between pass-through costs (e.g. paid to an RTO) and costs internalized by the utility. If not available, please provide such data in the format that is closest to that requested.

13. Please provide any studies or forecasts of the expected additional annual utility administration costs (e.g., additional costs associated with billing, customer service, interconnection applications) associated with [insert applicable distributed PV policies under consideration, such as net metering, time-of-use pricing, etc.] If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

14. Please provide any studies or forecasts that describe and detail any other annual utility costs associated with customer-sited PV. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

Participant Costs

15. Please provide any studies or forecasts of the expected PV purchase and installation costs borne by the participant for a typical residential PV system. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

16. Please provide any studies or forecasts of the expected operations and maintenance (O&M) costs borne by the participant for a typical residential PV system. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

Public Costs

17. Please provide the expected local, regional, state, and federal tax credits associated with a typical residential PV system for each year of the study.

Benefit Information ("Avoided Costs")

Utility System Benefits

18. Please provide any studies or forecasts of the expected avoided energy costs per kWh associated with customer-sited PV, for each year of the study. These avoided energy costs should be determined using the expected hourly output of a typical residential PV system and the associated avoided energy costs in that hour. Please include fuel, variable O&M, SO_X and NO_X allowances, and any reagents or other materials with a volumetric cost. Please also identify the number of MWh used in assessing the avoided energy costs per kWh. In other words, does it represent the marginal avoided energy cost of a single MWh or an aggregation of many MWh? If the latter, how many?

19. Please provide any studies or forecasts of the expected avoided generation capacity costs per kW or per kWh associated with customer-sited PV.

20. Please provide the expected generation capacity credit associated with typical residential customer-sited PV, for each year of the study, and the calculation of each capacity credit.

21. Please provide any studies or forecasts of the expected avoided transmission capacity costs per kW or per kWh associated with customer-sited PV for each year of the study. If it is expected that there will be incremental additional transmission capacity costs (rather than avoided costs) for any of the given years, please provide that information as well.

22. Please provide any studies or forecasts of the expected avoided distribution capacity costs per kW or kWh associated with customer-sited PV, for each year of the study. If it is expected that there will be incremental additional distribution capacity costs (rather than avoided costs) for any of the given years, please provide that information as well.

23. Please provide any studies or forecasts of the expected avoided environmental capacity costs associated with customer-sited PV. Include any applicable avoided Renewable Portfolio Standard compliance costs, avoided carbon trading costs (e.g. RGGI or California's Cap-and-Trade program), avoided Clean Power Plan compliance costs, and avoided costs associated with fossil or nuclear generators not explicitly included in the avoided energy costs. If available, provide such cost estimates in terms of dollars per kW or kWh for each year of the study. If not available, please provide such data in the format that is closest to that requested.

24. Please provide any studies or forecasts that describe and detail any other avoided utility costs associated with the typical residential PV system (such as reduced arrearages), for each year of the study.

Benefits for Regions with Wholesale Markets

25. Please provide any studies or forecasts of the expected energy-related Demand Reduction Induced Price Effect (DRIPE) for the utility associated with the typical residential PV system. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

26. Please provide any studies or forecasts of the expected generation capacity-related Demand Reduction Induced Price Effect (DRIPE) for the utility associated with the typical residential PV system. If available, provide such cost estimates in terms of dollars per kW for each year of the study. If not available, please provide such data in the format that is closest to that requested.

Public Benefits

27. Please provide any studies or forecasts that describe and detail the expected other public benefits associated with customer-sited PV. If available, provide such estimates in terms of dollars per kW or kWh for each year of the study.

28. Please provide any studies or forecasts that describe and detail the expected environmental externality benefits (e.g. the societal value of carbon not otherwise internalized) associated with customer-sited PV. If available, provide such estimates in terms of dollars per kW or kWh for each year of the study.

APPENDIX B: MODELING ASSUMPTIONS

To undertake this study, Synapse developed a spreadsheet model that estimates payback periods and, when combined with avoided cost inputs, estimates the cost-effectiveness and cost-shifting associated with distributed solar. Below we describe the key assumptions and inputs used to produce the results shown in this report.

Study Period

The study period for modeling purposes was 2016 through 2050 in order to capture the full life of the solar PV installed during the first five years (assuming a system life of approximately 30 years).

Utility System Attributes

Total residential customers: We assumed a utility system with 1,000,000 residential customers. For simplicity, we assumed no growth of customers over the study period.

Initial solar PV customers: We assumed 10,000 PV customers for the first year (1 percent of residential customers).

Customer Load

A typical residential customer load profile for a city in the Southwest based on the Department of Energy's Building America House Simulation Protocols was used to model customer energy consumption prior to installation of a solar PV system. The load profile was downloaded from: http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states. The average daily summer and winter loads for the customer are depicted in Figure 31, below.

For simplicity, this load profile was then assumed to represent the average residential customer, as well as the average solar customer. However, we note that in many jurisdictions, solar customers may have a higher-than-average usage profile prior to installing the solar PV system.

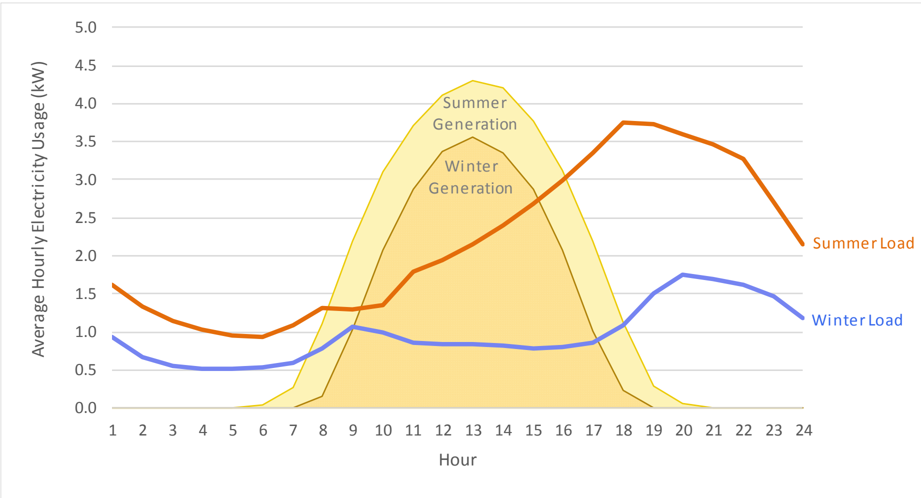
Solar PV System

System size: We assumed that the average residential customer installing solar would install a system sized to offset 88 percent of his or her load, which equates to an average system size of 6.53 kW_{DC}, with a DC to AC derating factor of 77 percent (based on the standard assumptions in NREL's PV Watts calculator http://rredc.nrel.gov/solar/calculators/pvwatts/system.html). The average summer and winter generation produced by the system are depicted in Figure 31.

Cost: We assumed an installed cost of $3.85 per watt for 2016, based on the continuation of cost trends reported by Lawrence Berkeley National Laboratory in *Tracking the Sun IX* (Barbose and Darghouth 2016). For additional installations for the years 2017–2020, we assumed that costs would continue to decline at the same average rate as observed over the period 1998–2015.

In addition, we assumed that the solar PV system would require maintenance over the system life. The annualized maintenance assumed was $21/watt, based on NREL's database of distributed generation technology operations and maintenance costs (available at http://www.nrel.gov/analysis/tech_cost_om_dg.html).

Figure 31. Average Customer Load and Generation Assumptions



Avoided Costs

As described elsewhere in the text, the net avoided utility system costs were assumed to be $0.113 per kilowatt-hour under the low utility avoided cost scenario, while the high net utility avoided cost was assumed to be $0.155 per kilowatt-hour.

Penetration

Maximum market size: To estimate the maximum potential market size, we used an estimate of 80 percent of residential customers, based on NREL's estimates of the percentage of small buildings that are suitable for rooftop solar (Gagnon et al. 2016). In some respects, this represents an optimistic value, as many of the occupants of these buildings are likely to be tenants, rather than owners. However, limiting the number of customers due to home ownership status may be overly conservative, as it does not account for community solar and other forms of virtual net metering.

Market penetration curves: For the purposes of this analysis, the most recent NREL adoption curves for residential customers were used to estimate the ultimate penetration of distributed solar (Sigrin et al. 2016). See Figure 6 in Section 3 for more information. However, instead of using the ultimate penetration value, we estimated an interim penetration level, i.e., what the penetration would likely be after five years, rather than in the long term.

We employed the Bass Diffusion Model (Bass 1969) to estimate the S-curve growth pattern and to develop an estimate of the five-year penetration level. To specify the S-curve, we assumed that the maximum would be reached in year 10. For modeling purposes, we followed the S-curve until year five, and then held the penetration level constant for the remainder of the study period. For example, the figure below shows the penetration levels assumed for the alternative compensation scenarios.

Figure 32. Example 5-Year Distributed Solar Growth Assumptions