GETTING IT RIGHT:
POLICY RECOMMENDATIONS FOR THE GRID INTEGRATION OF DISTRIBUTED PV

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Abstract

The expansion of distributed PV in the United States is causing tension in the electric utility industry, as current business models and regulations are sub-optimal for managing significant levels of customer-owned distributed PV. This report explores the following question: What state-level utility policies can most appropriately value grid-connected distributed PV generation in a way that is equitable to all stakeholders?

We performed a review of secondary literature as well as primary interviews with electric industry experts with the focus of analyzing two primary pricing inefficiencies common in electricity rates: the allocation of fixed costs for the electric grid into volumetric rates, and the valuation of solar PV. The final segment of supporting research is the team's original economic modeling analysis, which consists of two models: A utility rate model which uses generalized cost components and features of a prototypical regulated utility to estimate the potential economic impact of distributed PV generation on electricity rates; a solar project model which estimates the impact of different utility fixed-cost charges and compensation rates on distributed PV project economics.

Based on the above research, we offer three recommendations for state-level policymakers to value grid-connected distributed PV generation in an equitable manner. The foundation of our recommendations is that electricity service components must be priced separately; each customer should be aware of his or her fixed cost obligations. Secondly, we recommend a shift away from pushing the majority of a residential customer's bill onto per kWh charges, and separate the pricing of having access to the grid from the use of electricity, similar to pricing structures used in the telecommunications industry. Lastly, the pricing of kWh sold onto the grid from distributed PV systems should be the result of a comprehensive evaluation of the value provided to the grid.

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Disclaimer

Opinions expressed in this report represent a consensus of the authors and do not necessarily represent the official position or policies of the University of Michigan o the Edison Foundation Institute for Electric Innovation, or DTE Energy.

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Executive Summary

The adoption of distributed solar photovoltaic (PV) technology is quickly expanding in the United States, partially as a result of declining PV costs and renewable energy policies on the local, state and federal level. This expansion of distributed PV is causing tension in the electric utility industry, as current business models and regulations are sub-optimal for managing large penetrations of customer-owned distributed PV. Utility companies are losing electricity sales to PV-owning customers, and this causes revenue losses and put pressure on electricity prices for non-PV owners, which creates a social equity problem. Higher electricity prices could also encourage more customers to install PV systems, exacerbating utility revenue losses and continuing in a cycle that has been referred to as the "utility death spiral."

In most jurisdictions, the existing configuration of electricity rates and PV net metering is economically inefficient by not compensating the utility for investments in fixed grid infrastructure that PV owners still rely upon. Furthermore, besides inefficient grid valuation, the power provided by solar PV is arbitrarily and inefficiently valued at the retail rate of electricity; some stakeholders argue that net metering at the retail price is too low, and others argue it is too high for the true value of solar. We offer some suggestions on ways to address these inefficiencies.

The research team at the University of Michigan School of Natural Resources and Environment and Ross School of Business, in cooperation with the Edison Foundation's Institute for Electric Innovation and DTE Energy, investigated the causes, consequences, costs, and benefits of the growth in distributed PV in the US. The central research question is:

What state-level utility policies can most appropriately value grid-connected distributed PV generation in a way that is equitable to all stakeholders?

In this report, we consider the perspectives of key stakeholders, including utility companies, electricity consumers, policymakers, and advocacy groups, and present recommendations for state-level policymakers and utility regulators to address the challenges of valuing distributed PV and the electric grid.

Following a review of secondary literature as well as primary interviews with electric industry experts, the research scope was defined and key issues pertaining to distributed PV were identified. We analyze two primary pricing inefficiencies common in electricity rates: the allocation of fixed costs for the electric grid into volumetric rates, and the valuation of solar PV. The expected transition in the power sector to incorporate more distributed energy

resources has been compared to the telecommunication sector's disruptive transition to cellular technology. Particular lessons from the telecommunications literature, such as the efficient component pricing rule, are featured in our analysis and impact the policy recommendations. The efficient component pricing rule focuses on economic efficiency by allocating the fixed and variable prices in a rate structure that matches their costs, and allocating costs fairly across classes of consumers and service providers.

Another key aspect of this research is the identification and analysis of state case studies and cutting edge state policy examples. After reviewing ten possibilities, we focus on five of the top states for distributed PV growth to glean lessons on drivers and impacts: California, Arizona, New York, New Jersey, and Massachusetts. For each state, we examine the utility landscape and regulatory regime, electric load profile, distributed PV penetration, and relevant policies. In addition, we discuss the following recent examples of progressive rate tariff models: Arizona solar access charge, California fixed charge, Austin Energy value of solar (VOS) tariff, and Minnesota VOS tariff. Based on VOS examples and literature, we enumerate the major costs and benefits of distributed PV, such as avoided costs for fuel, capacity, and line losses, and environmental and social benefits.

The final segment of supporting research is the team's original economic modeling analysis, which consists of two models:

- **Utility rate model** – This uses generalized cost components and features of a prototypical regulated utility to estimate the economic impact of distributed PV generation on electricity rates. The model is sensitive to a number of parameters and estimates the magnitude of lost fixed cost recovery and the corresponding electricity rate change due to a certain level of net-metered distributed PV and different levels of fixed charges. The calculated lost fixed cost recovery amount is equivalent to the cost shifting from distributed PV owners to non-owners.
- **Solar project model** – As a complement to the utility rate model, the solar project model estimates the impact of different utility fixed-cost charges and compensation rates on distributed PV project economics. Given a range of fixed costs charged to distributed PV owners along with varying net metering or value of solar compensation paid to PV owners, the model estimates the point at which the cost of a distributed PV system becomes uneconomical and equal to the retail price of grid electricity, which is linked to the utility rate model. As a result of both models, a combination of rate options is produced that will achieve a certain revenue level for the modeled utility while remaining economical for the modeled PV owner.

Summary findings from our generalized model of a sample California utility estimate that a 1% penetration of net-metered PV owners could yield a rate increase of 1.66% for non-PV-owning residential customers. To avoid all shifted costs, a fixed fee of approximately $70 would be required for each PV owner on average, which would put PV owners at a loss on their PV system investment. If PV owners are charged a fixed fee of $10 per month or $20 per month, we estimate that the shifted costs to other customers would be, respectively, 1.43% and 1.19%, and PV system investments would remain economical. With a better understanding of these tradeoffs, we contend that a compromise solution exists in which non-PV-owners absorb a portion of the utility's shifted fixed costs to serve PV owners, which is justifiable given the external economic, societal, and environmental benefits of solar. Whereas, holding PV owners accountable for a majority of the costs of utility services that they incur, while preserving a positive return on investment for PV systems, is also justifiable. The key takeaways from the modeling exercise contribute to our policy recommendations and should further inform the discussion on distributed energy policy. However, we caution that the models are general and in their current form should not be applied to a specific state or jurisdiction without adjusting the parameters in more detail.

Finally, based on the research and analysis included in this assessment, we offer three recommendations for state-level policymakers to value grid-connected distributed PV generation in an equitable manner. Utilities argue that net metering programs allow distributed customers to avoid their fixed cost obligations, and call for lower credits for kWh generated from distributed PV systems. Solar advocates argue that kWh from distributed PV systems create value for the utility, and call for higher credits. We propose that both positions hold merit, and that the solution lies in accurately and separately pricing fixed cost obligations and the value of solar kWh.

Our recommendations are based upon the principle that utilities must be given the tools necessary to adequately recover investments in long-term assets, such as distribution lines. The current practice of recovering both fixed and variable costs through volumetric rates, i.e. sale of kWh, limits the utility's ability to properly recover its costs, especially with existing net metering programs.

- **We recommend** that electricity prices be aligned with the cost of electricity service components. Decoupling both fixed cost obligations and the value of solar from the volumetric portion of the electricity rate will result in more economically efficient pricing and reduce the unintended consequences of widespread penetration of distributed PV.

- **We recommend** that fixed costs are priced and charged to customers through a separate rate mechanism that diminishes cost-shifting between customers. Doing so would address the first identified pricing inefficiency.

- **We recommend** that the value assigned to kWh generated from distributed PV be calculated using methodologies similar to those used in VOS tariffs, in order to address the second pricing inefficiency. The value of kWh from distributed PV systems is contingent upon various factors such as the avoided cost of generation and avoided line losses that are specific to each state and utility, and each state may calculate the value differently.

Introduction

Problem Statement

The rapid rise of distributed PV has created conflicts of interest between some investor-owned utilities and solar industry proponents over appropriate state-level policies for managing the growth and integration of PV into the electric grid. This paper examines two of the main economic conflicts:

1) The appropriate amount of fixed charges for grid access
2) The appropriate value of distributed PV generation

Improvements in technology, new innovative solar business models, policies on all levels of government encouraging renewable energy, and rising energy prices have made distributed solar photovoltaic systems (distributed PV) increasingly attractive for residential and commercial utility customers as a means to generate some or all of their own electricity. Since 2010, US installed PV capacity has grown dramatically—from 2,006 megawatts (MW) in 2010 to 13,000 MW as of December 2013. In 2013 alone, 4,751 MW of additional PV capacity came online in the US.[1] While PV currently represents only one percent of the US's total overall electric generation capacity, its share is likely to increase further, with EIA estimates indicating PV generation nearly triples from 5.8 million Gigawatt-hours (GWh) in 2013 to 16 million GWh in 2030.[2] In addition, certain states already have higher penetrations of PV concentrated on their local networks, creating power quality issues in the distribution system. It is of critical importance that appropriate policy measures be developed in a judicious and timely manner.

A large portion of PV growth is anticipated to occur in the residential sector, as growing numbers of utility customers supplement their electricity consumption by installing grid-connected distributed PV. Moreover, the growth in distributed PV is expected to continue due to environmental considerations; regulations on mercury and other air toxics contribute to traditional fossil fuel capacity becoming more expensive and less desirable. Furthermore, given that current U.S. carbon emissions are still above 1990 levels and given that electricity generation accounts for 38% of U.S. carbon dioxide emissions,[3] political pressure on the power industry to adopt PV and other renewable technologies seems likely to remain.

Given distributed PV system size and generation limits imposed by local policies and economic costs, most distributed PV owners still rely on traditional electric grid access to supplement their overall electricity consumption. PV owners also utilize the electric grid to sell their excess PV generation and receive net metering credits above the avoided cost of generation. The fact that utilities must build and maintain grid infrastructure to serve distributed PV customers who are still connected to the grid poses a challenge for the traditional cost recovery mechanisms of utilities. Utilities stand to lose a substantial amount of revenue as distributed PV customers buy less electricity from the utility, while the investment and upkeep costs associated with the overall grid remain the same. Because most customers with distributed PV still depend on the grid during periods of intermittent or insufficient self-generation, utilities will have to maintain the same overall infrastructure and power-generating capabilities to serve all customers, even as revenues decline due to customers self-generating their own electricity.

The current economics of distributed PV, combined with utility cost shifting created by increased distributed PV penetration, also has consequences for societal equity. First, because residential PV systems are often financed through a leasing structure, customers with low credit scores or those who do not own a home may not have equal access to install PV and take advantage of resulting tax incentives that further lower system costs. Secondly, low-income and other ineligible households may be "stuck with the bill," as utilities are forced to raise rates for *all* electricity customers, due to falling revenues as distributed PV customers buy less electricity. Compared to customers without distributed PV, those with PV systems still receive the same services from the utility but ultimately pay less to do so. As a result, some utility customers will pay increasing electric rates, while customers with the economic means are able to switch to cheaper alternatives. Overall, utility customers who have no choice but to remain on the grid may still have electrical service, but that service will be increasingly expensive. This cost-shifting phenomenon is particularly relevant to conversations about the widening wealth gap in the U.S.

On the other side, solar advocates argue that customers with distributed PV may in fact be under-compensated for the overall benefits they provide to the utility and society at large. Solar advocates cite benefits such as the avoided infrastructure and operating costs for energy generation, transmission and distribution, as well as environmental benefits. The exact costs and benefits to be included is the subject of widespread debate, as they vary depending on a multitude of factors. Without deciding whether net-metering values distributed PV too high or too low however, the main discrepancy with net metering from an economic standpoint is that it is arbitrarily set at the retail rate of electricity. A more rigorous valuation of PV should incorporate all prudent, significant benefits and costs of solar PV to arrive at a value of PV independent of the retail rate. Recent test cases that evaluated the value of solar as in Austin, Texas and the state of Minnesota are discussed below.

Currently, distributed PV technology has not achieved sufficient market penetration to represent a significant disruption to the utility business in the US, yet PV penetration is anticipated to continue growing due to declining PV costs, renewable energy incentives, and environmental and greenhouse gas policies. In Europe, where distributed PV has seen faster adoption and higher penetration, utilities have seen their market value halve since 2008 and many of the largest saw their credit ratings reduced.[4] The decline in credit quality will lead to a higher cost of capital, putting further pressure on customer rates. While these effects are not solely due to distributed PV, it is apparent that the utilities' traditional business model is not sufficiently flexible in this transforming landscape. Because existing business models are determined by regulation, innovative regulation and rate structures will be necessary to provide sufficient flexibility in an evolving electric power sector.

Scope

Forward-looking utilities recognize the need to adapt to the rising share of distributed PV, especially as technologies like solar photovoltaic panels become more and more affordable. For utilities to be able to make comprehensive adjustments to their business model, policies must be adjusted as well, mostly at the state and regional level. There is a significant amount of published research on various aspects of distributed PV, especially on technical topics. Government entities such as the Department of Energy National Renewable Energy Laboratory (NREL) frequently release technical reports. Several non-governmental organizations have published studies of distributed PV policy, and utility rate regulation has been a heavily researched topic for decades.

This project brings together a review of existing literature with primary research to provide guidance for state-level policymakers to evaluate the effects of distributed PV implementation over a 20 year timeframe. The primary research includes five state case studies, models of solar tariff impacts on utility revenues, electricity rates, and PV project viability, collection and comparison of PV valuation methods, and select expert interviews. The value added by this project to the present discourse on distributed energy in the electric power sector results from the combination of:

- A utility-scale revenue/cost model sensitive to various rate schemes;
- A PV project economics model connected to the utility rate model's scenarios;
- An approach to rate design focused on economic efficiency that draws on lessons from the telecommunications sector;
- The inclusion of recent examples, surveys, and methodologies for valuing the economic, social, and environmental benefits and costs of distributed PV.

Based on this assessment, we crafted recommendations for state-level regulators and policymakers to handle the state policy changes that will be necessary in the next 10 to 20 years for territories that are witnessing or will witness high penetrations of distributed PV. Our recommendations aim to help formulate state-level policies ensuring the long-term reliability of the electric grid, continued low cost electricity, and a diverse portfolio of power generation sources in the U.S. Given the emergence and increasing adoption of technologies related to renewable energy, smart grid applications, and electric transportation, as well as continued national concern about climate change and other environmental impacts,[5] we assume that the proliferation of distributed PV capacity will continue and that new state and federal policies will be needed to accommodate it.

We define "distributed" as a unit connected behind an electricity customer's meter, which is located on-site or near load and outside of the control of a utility or system operator. Throughout this report where not otherwise indicated, "distributed PV" will refer to *grid-connected* distributed PV that can send power to the main electric grid, as opposed to untied or micro-grid-connected PV systems. Although there are many types of distributed energy technologies, the scope of this analysis focuses on solar PV technology, typically in the form of PV panels mounted on roofs or on ground mounts.

Other types of distributed energy technologies, such as combined heat and power and small scale generators powered by diesel or biomass have been in use for decades and do not yet pose the same challenges to integration into the regulatory system and utility business model as widespread solar adoption. Backup generators typically only run in cases of power loss or other emergency. Industrial and commercial natural gas, diesel, or biomass fueled generation units do not introduce as much intermittency as PV supply does. Furthermore, these technologies have not been growing at the accelerated pace of PV. Small scale wind turbines mirror the issues of variability like solar resources, but have not been adopted at an equivalent rate. Energy storage resources, such as battery systems, are not generators of electricity, however they present a technically effective complement to distributed PV systems by storing excess electricity until it is needed. Currently, battery storage costs are much too high to be economical, but declining battery costs would influence PV system economics. An expanded evaluation is needed in the future, but focus of this paper is on PV, and data on residential PV systems coupled with batteries is scarce. In the near term, solar PV will be the first widespread technology that is distributed and intermittent, and therefore will challenge the utility's ability to recover fixed costs through existing rate structures at a significant scale of impact.

The report delivers research on best regulatory practices and state-level policy insights for how the utility industry, state-level policymakers, and industry regulators can best incorporate distributed PV generation into the existing utility economic framework. These deliverables will be useful, because they shed light on distributed PV utility integration practices across the United States, while providing meaningful actions that utilities and policymakers can take to meet the needs of stakeholders in a deliberate, transparent, and reasonable approach.

Origin of the Problem

History of the Power industry and Electricity Pricing

An understanding of the historical context of the utility industry—including its traditional cost structure, the industry's regulatory framework, and its public service obligations—is necessary to evaluate current state policy options to fairly manage distributed PV penetration across the grid for all stakeholders. A stipulation for utilities grappling with current state-imposed distributed PV ratemaking and incentive policies is that current mechanisms (e.g. net metering) do not fully compensate utilities for their costs, as necessitated by the regulatory compact.

Traditional Utility Industry Framework

Natural Monopoly

Utilities have traditionally operated as regulated natural monopolies in the U.S. The historical means of producing and distributing electricity are such that a large single electricity provider can provide electricity at lower average costs than smaller entities—known as economies of scale. States and municipalities granted utilities' natural monopoly status within their respective service areas to improve the overall efficiency of the power generation and distribution system for both ratepayers and utilities alike.

Regulatory Compact

Because they operate as natural monopolies while providing what is deemed a public good—electricity—utilities' operating practices and prices are generally regulated by federal, state, and local public agencies. Through what is broadly known as the Regulatory Compact, a utility accepts an obligation to serve the public, and in exchange the government promises to set electricity rates charged by the utility that will fully compensate the utility for its costs. The rates utilities charge customers are reviewed and approved by regulatory agencies within their operating region. Regulatory agencies govern most aspects of utilities operations: electricity prices, customer service agreements, investment activities, and other public programs.[6] To incentivize the utility to operate efficiently, regulators permit the utility to earn a fair return on investment (ROI), assuming the utility confirms to regulatory guidelines and practices.[7] Ultimately, utilities' existence as a regulated monopoly ensures that consumers get safe, reliable, affordable supplies of electricity while utilities cover their investment and operating costs.

Obligation to Serve

A key element of the regulatory compact between utilities and public is utilities' "obligation to serve" all areas of the service territory to which they have been granted exclusive rights by the governing body. This obligation means that utilities cannot selectively pick and choose to provide better (or any) service to certain areas (e.g. more profitable areas) of their service area over other areas. This obligation to serve means that utilities must invest in transmission and other infrastructure costs to supply electricity equally to all areas of its service territory. The issue of obligation to serve is important when considering that utilities must make what might not necessarily be stand-alone profitable generation and distribution investments for a given area of service.

The Fully-Integrated Utility

Over the last 50 years, the U.S. electric power industry has been dominated by large, vertically integrated utilities operating as natural monopolies and benefitting from falling long-run average total costs. Under a vertically integrated operating structure, a single utility company controls electricity generation, transmission and distribution of electric power for a given market within one or more service areas.

Historically, the vertical integration of utilities made sense for utilities and ratepayers. As the cost of building larger and more efficient power generation facilities was spread over an ever-increasing rate-paying customer base, utilities saw a continuous decrease in their marginal production costs, allowing them to profit while decreasing rates for customers—a "win-win" situation for all stakeholders. Most importantly, for the consideration of distributed PV in today's context, utilities' natural monopoly status depended on a large rate-paying customer base over which the utility could offset high generation, transmission, and distribution capital and operating costs.

Similarities to the Telecommunications Industry

The telecommunication industry grew up in a similarly regulated environment as the electric utility industry. Both industries require large capital investments that connect nearly every household in America. Both industries were required to service all U.S. households, whether or not they were profitable or used the service. This is often referred to as the obligation to serve and is defined by widespread access, ease of accessibility, and affordable rates for all citizens. As we will see further below, in many ways, electric power is going through a similar transition to the telecom industry in the 1990s when deregulation introduced competition in local telephony, which cut off a reliable source of revenues for phone companies.

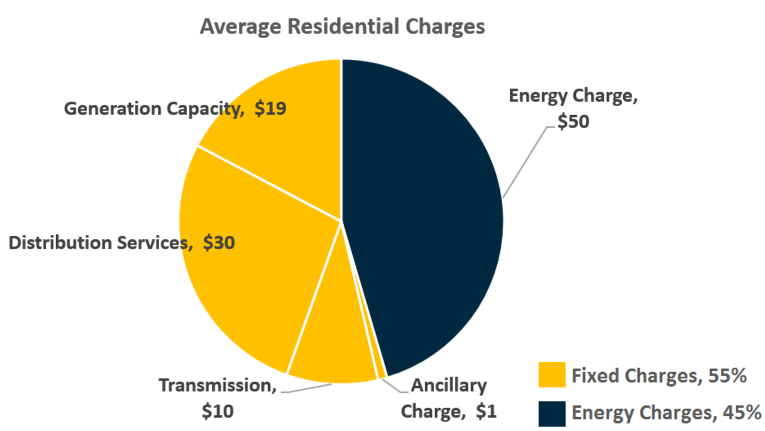
Rate Structure and Cost Recovery

The structure of utility rates—that is, the various allocations of cost and return on investment implicitly built-in to rates utilities charge customers—is at the core of the challenge of more broadly integrating distributed PV into the grid. To remain financially sound, rates must produce sufficient revenues to cover the cost of infrastructure and other expenses needed to provide electric service today and in the future. A utility's operating expenses, such as wages, salaries, supplies, maintenance, taxes, and research and development, are most often the largest component of the revenue requirement.

In the electricity market, regulation replaces competition as the determinant of prices. Rates are based on actual utility costs of providing service, including a reasonable return on investment for providing service for each customer class (residential, commercial, and industrial), not the marginal cost of power in the marketplace. This means that rates are set to recover those costs, based on the sales volumes for each class. Additionally, ratemaking can serve other, non-economic purposes. Ratemaking also involves redistribution of wealth within classes of customers. For example, low income households may be eligible for subsidized energy charges funded in part by middle and higher income households.

The allocation method for these charges varies depending on the utility and on the customer's class and subclass. For different customer types, rate structures are set differently to recover costs. Residential customers frequently pay the vast majority of fees through volumetric rates. Because of this, a net metering customer will avoid paying some or all of its fair share of the fixed costs of grid services. As seen in Figure 1, about half of the average customer bill includes charges related to the non-energy services provided by the grid, including a charge for generation capacity. There are a variety of methods of charging customers to recoup these costs.

Figure 1: Average U.S. Residential Retail Electricity Bill Breakdown[8]



Electricity Tariffs

The following section details some of the various types of charges that utilities can implement. Electricity bills display the energy tariffs that are used to calculate the total cost of your bill. Utilities vary in how they appropriate charges under different fees. The design of rate tariffs strive to accomplish several goal simultaneously including consumer price signals, operating efficiency signal, and investment signals. The regulated utilities costs, including their rate of return, are recovered through electricity charges. Utility rate structures are largely based on averaged costs rather than economic efficiency. The varieties have evolved over time as local PUCs approved different pricing schemes.

Customer charge — The "customer charge" component of a customer's rate is a recurring, flat fee charged monthly regardless of the customer's energy use. The customer charge typically covers administrative costs, such as billing, postage and building rent costs. In most states customer charges are often lower than the fixed costs to deliver electricity to that customer, particularly for residential class customers, leaving the remaining costs to be bundled into energy rates on a per-kilowatt-hour (kWh) basis.

Energy charges — "Energy charges" are the variable customer charges associated with that customer's energy use during a given billing period. In theory, energy charges should represent the variable costs to generate and deliver electricity—costs such as fuel, maintenance, and purchased energy costs. In practice, for small customer energy charges often include fixed investment costs and are averaged across the utility's overall customer base. Energy charges can differ in a number of ways: by charging more or less as electricity consumption increases within a tiered pricing structure; by increasing prices at on-peak periods versus lower off-peak rates; or by offering differentiated time-of-use (TOU) pricing. Energy charges usually represent the largest share of residential and small-commercial customers' bills, but could be a smaller portion for large commercial and industrial facilities and net-metered customers.

Demand charges — For customers with high electricity consumption, typically large commercial, industrial, and municipal facilities, utilities incorporate what is known as "demand charges" into rates. Demand charges correspond to the peak power (measured in kW or MW) demanded by that customer in a certain time period—typically over one month. The demand charge is directly related to the capital investments required to meet a customer's power demand at the peak time.[9] Providing that peak capacity requires the energy provider to own and operate, or maintain access to, a certain level of generation, transmission, and distribution infrastructure, which contributes a substantial portion of total system costs.

Standby rates — Standby rates are typically set for self-generating entities that are mostly independent of the grid, such as micro grids or industrial facilities with CHP, which need access to the grid for backup power in emergencies or other outages. Standby or backup charges have also been instituted or proposed for other distributed PV technologies. Standby rates include energy rates consumed per-kWh as well as customer charges and demand charges per-kW representing the fixed costs associated with servicing the customer and providing access to reliable power from the utility. These charges could vary depending on whether the outages are planned and scheduled ahead of time versus unscheduled, such as due to solar or wind intermittency. The balance of energy and demand fees in standby rates can vary greatly and may include ratcheted demand charges.

Grid Costs

This section describes the grid services and their associated costs. These services support the movement of electricity to power producer to customer. The utility's cost of providing grid services consists of at least four components: generation capacity, transmission, distribution, and ancillary and balancing. These services provide value to all grid connected customers throughout the day.

Generation Capacity — Electricity generation is the process of generating electric power from other sources of primary energy such as coal, natural gas, wind, or solar. The generation fleet of facilities range from large power plants that produce baseload power and smaller plants that may only generate power at peak times. The facility costs include the large upfront charge of construction. Fuel costs are based upon the amortized costs associated with the purchasing, storage, and shipment of the fuel. Renewable fuels choices often operate with free energy inputs. Other operation and maintenance costs include labor, material & supplies, licensing fees, and regulatory fees. These costs can be bundled to calculate the levelized cost of energy which is the price at which electricity must be generated from a specific source to break even over the lifetime of the project.

Transmission — Electric-power transmission is the bulk transfer of electricity from power plants to electrical substations located near demand centers. Transmission lines, when interconnected with each other, become transmission networks which allow for the transfer of electricity over long distances. The actual wires also provide some electricity storage which increases reliability. Transmission systems consist of above-ground lines and towers that cross large stretches of the country. The cost of high voltage electricity transmission is comparatively low, compared to all other costs arising in a consumer's electricity bill.

Distribution — Electricity distribution is the final stage in the delivery of electricity to end users. A distribution system's network carries electricity from the transmission system and delivers it to consumers. They are part of a network that typically includes medium-voltage power lines, substations, pole-mounted transformers, low-voltage distribution wiring and meters. Charges for the use of local wires, transformers, substations, and other equipment used to deliver electricity to end-use consumers from the high voltage transmission lines.

Ancillary and balancing services — The United States Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."[10] The costs of energy services are simple to quantify: investment equals average capital cost plus average customer acquisition cost multiplied by the number of customers. Actual hardware ranges from capital intensive backup energy storage systems to sensors and control software.

Understanding the costs of the utility reveal the value offered reliable electricity. The electricity grid is a vast system constructed over decades and requires continuous investment. The variety in electricity tariffs demonstrates that charges are a compromise full of economic and political nuance as the needs of various stakeholders are weighed.

The Rise of Distributed Photovoltaic Generation

The traditional utility industry described in the previous section comprises a century of centralized power generation. This paradigm of centralized power production is now changing with the spreading of distributed photovoltaic systems.

Definition of Distributed Generation and Distributed PV

Many definitions of distributed generation exist in scientific and engineering literature. This report will use the definition proposed by Ackermann, et al in their paper, Distributed Generation: A Definition. According to Ackermann, "[Distributed generation] can be defined as electric power generation within distribution networks or on the customer side of the network."[11] In other words, while traditional electricity generation occurs at central stations far away from where the demand is and transported through a transmission network, distributed generation supplies electricity either directly to the end consumer on site, or it is fed into a local distribution grid. A crucial detail for this paper is the fact that residential- and commercial-sited distributed generation generally occurs "behind the meter", meaning that from the viewpoint of an electric utility, the effect of distributed generation is a reduction of the customer's electricity demand or an import of electricity from the customer site to the grid.

While distributed generation encompasses a number of technologies such as conventional diesel generators, small-scale wind turbines or commercial-scale battery systems, the primary focus of this study is distributed solar photovoltaic technology ("distributed PV"). Distributed PV plays a different role than other technologies; unlike diesel or gas generators, distributed PV is meant to supply electricity on a routine basis, and unlike distributed wind turbines or, at present, commercial storage, distributed PV is seeing widespread adoption across the United States. Finally, not all PV systems are distributed; utility-scale PV systems are not distributed PV.

Societal Benefits of Distributed PV

To understand the political context in which distributed PV is embedded, it is important to recognize that there are a number of positive externalities that distributed PV technology can provide. They can be significant, but are difficult to systematically account for in electricity regulation, not least because views differ regarding scope and magnitude of the externalities. While a comprehensive answer to these questions is beyond the scope of this paper, we believe that awareness of the societal benefits of distributed PV is conducive to a more informed discussion. In the following is an overview on the environmental, public health, and economic development benefits provided by distributed PV.

Environmental Benefits

Reduced Pollutants Emissions Compared to Fuel-fired Electricity Generation

Electricity production accounts for more than one-third of U.S. global warming emissions. Coal-fired power plants account for 25 percent of total U.S. global warming emissions; natural gas-fired power plants produce 6 percent of total emissions.[12, 13] Furthermore, fossil fuel-fired power plants are responsible for 40 percent of man-made carbon dioxide (CO_2) emissions, 23 percent of the nation's nitrogen oxide (NO_X) emissions, and 67 percent of sulfur dioxide (SO_2) emissions.[14]

In contrast, distributed PV produce little to no global warming emissions or pollutants, even when accounting for their entire lifecycle from manufacturing, installation, operation and maintenance, to their final dismantling and decommissioning. Therefore, major environmental and health benefits are expected from a gradual shift in electricity generation from fossil fuels to more distributed PV.

For example, A 2007 Wisconsin study measured CO_2, SO_2, and NO_X emission reductions from the state's Focus on Energy program and found annual emission displacements of over 1,360,000 tons of CO_2, 2,350 tons of SO_2, and 1,436 tons of NO_X from 2001 through 2007.[15] These reductions respectively represent about 2 percent, 1 percent, and 2.5 percent of Wisconsin emissions in 2005.[16]

Reduced Harm to Water Resources

Fossil fuel-fired power plants depend heavily on water resources, both for their operation and for fuel extraction. All thermal power plants, including those powered by coal, gas, and oil, withdraw and consume water for cooling. Natural gas extraction by hydraulic fracturing requires large amounts of water, and coal mining and drilling for gas regularly pollutes sources of drinking water.[17] In comparison, PV systems other than Concentrated Solar Power require essentially no water to operate.[18] PV therefore offers benefits in the protection and conservation of water resources, and can reduce water supply strains from competing uses for agriculture, drinking water systems, or other important water needs.

Health Benefits

Fossil fuel-based electricity generation is a major source of air pollutants that pose serious risks to public health, such as increased respiratory illness from fine-particle pollution and ground-level ozone. Such health impacts have been related to total emissions of NO_X and SO_2, which react with other chemicals to form fine particulate matter (PM2.5) in the air.[19] The EPA and the Clean Air Task Force have developed benefit estimates, utilizing detailed air quality models to estimate PM formation based on NO_X and SO_2 emissions. They have found a highly correlated relationship between pollutants and the estimated health impacts. If distributed PV systems offset fossil fuel-based electricity generation, they therefore provide direct public health benefits. Avoided illnesses associated with upper and lower respiratory illnesses and cardiac arrest result in reductions in sick days taken by employees, increases in productivity, and decreases in hospitalizations. Avoided deaths of workers can result in continued economic benefits to the state.[20]

Economic Development

Job creation is one of the main arguments behind energy-related policies targeting fossil technologies and renewable alternatives alike. The growth of distributed PV undisputedly creates jobs, but a key difficulty in assessing the job numbers used by advocates and proponents of incentives for distributed PV is that it is often not clear what they are based on.[21] In the following, we provide an example of how the economic development impact of distributed PV can be measured and what order of magnitude the impact is.

Measuring Economic Impact: the JEDI – PV Model

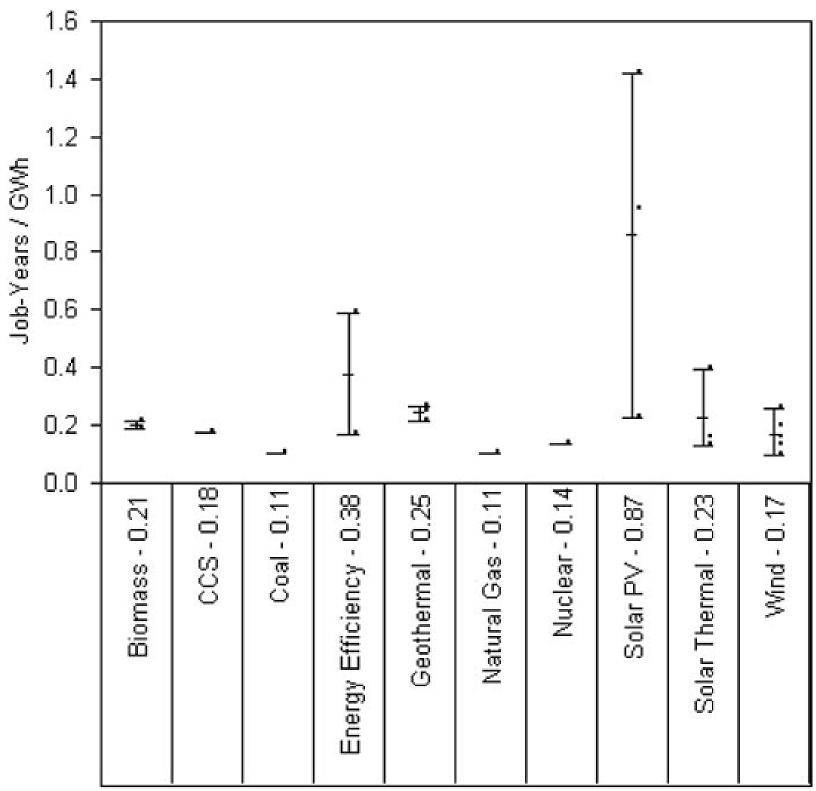
The National Renewable Energy Laboratory (NREL) has developed the “Jobs and Economic Development Impact” (JEDI)-PV model to estimate the gross national employment and economic impacts of the construction and operation of PV systems.[22] It is based on an input-output methodology and typically uses “Residential New Construction”-scale projects installed in different states in the U.S. in 2013. The JEDI model has previously been used to estimate the economic impacts of individual generation projects, as well as the impacts of broader investment in renewables. Model users include the U.S. Department of Energy (DOE), NREL, etc.

JEDI-PV Model Inputs

For evaluating each individual projects, the minimum inputs for the JEDI-PV model are the nameplate generation capacity (MW), location (United States), year of construction, and installed system costs ($/kW). The computations here uses default value provided by JEDI-PV for more detailed cost breakouts, financial parameters, O&M costs, and other assumptions when not specified. For the input data, we relied extensively on papers we considered more comprehensive, presenting for instance jobs/MW data along with person-years data; other existing studies don’t necessarily cover all components of employment, such as manufacturing, construction, installation, operations and maintenance, and fuel processing.[23]

Figure 2 below shows the average and range of direct employment multipliers per unit of energy for ten different energy technologies. It is apparent that PV has the highest average job multiplier with a large gap between it and the next highest renewable technologies (geothermal and solar thermal). This is likely due to installations of distributed panels, which are more labor intense than for example the installation of a wind farm in one single location.

Figure 2: Average and Range of Direct Employment Multipliers Energy Technologies[22]



JEDI-PV Model Outputs

The most relevant variables measuring the impact of distributed PV on the entire economy are employment, earnings, and output (GDP), which represent the entire economy as a system of interactions or linkages between subsectors.

In the Input-Output computations, jobs and economic impacts are categorized into three groups: direct, indirect, and induced. For distributed PV systems, direct jobs are associated with the design, development, management, construction/installation, and maintenance of generation facilities. Indirect jobs are associated with the manufacturing and supply of equipment, materials, and services for the generation facility, as well as the upstream suppliers that provide raw materials and services to these manufacturers. Induced jobs include the jobs and economic activity that occur as a result of spending earnings by individuals directly and indirectly employed by the projects, which could include jobs at local retailing, restaurants, and schools, etc. The sum of these three effects determines the total economic and employment effects (or impacts) that result from expenditures for the construction and operation of a solar plant.

The following case study will illustrate the estimated impact on direct and indirect jobs and associated economic activity of a solar PV program in California.

Case study: California - The New Solar Homes Partnership (NSHP)

To gain a better understanding of the job creation associated with distributed PV the team ran the JEDI-PV model for the NSHP. This case study takes NSHP as an example to evaluate the potential socio-economic benefit that could be generated to California, by estimating the direct and indirect jobs and economic impacts of projects under NSHP. The analysis employs the Jobs and Economic Development Impacts (JEDI) models to estimate the gross jobs, earnings, and economic output supported by the construction and operation of solar photovoltaic (PV) NSHP projects.

The NSHP is part of a comprehensive statewide solar program known as the CSI. Senate Bill 13 establishes three goals for the CSI: 1) install 3,000 megawatts (MW) of distributed solar electric capacity in California by the end of 2016; 2) establish a self-sufficient solar industry in which solar energy systems are a viable mainstream option in 10 years, and 3) place solar energy systems on 50 percent of new homes in 13 years. The NSHP goal is to add 360 MW of installed solar electric capacity in California by the end of 2016.[24]

Figure 3: California's "New Solar Homes Partnership" Program Totals

	Number of Applications	Number of Systems	Dollars (Millions)	Capacity (MW AC)
Under Review	223	4188		
Reserved	709	13971	79.3	40.3
Installed	1811	11653	95.8	37.4
Total	2743	29812	175.1	77.7

Figure 4: Photovoltaic Project Data Summary

Photovoltaic - Project Data Summary

Project Location	CALIFORNIA
Year of Construction or Installation	2013
Average System Size - DC Nameplate Capacity (KW)	285.0
Number of Systems Installed	2743.0
Project Size - DC Nameplate Capacity (KW)	781,755.0
System Application	Residential New Construction
Solar Cell/Module Material	Crystalline Silicon
System Tracking	Fixed Mount
Total System Base Cost ($/KWDC) [?]	$7,781
Annual Direct Operations and Maintenance Cost ($/kW)	$32.80
Money Value - Current or Constant (Dollar Year)	2010
Project Construction or Installation Cost [?]	$6,083,015,377
Local Spending	$4,042,139,952
Total Annual Operational Expenses	$707,816,370
Direct Operating and Maintenance Costs	$25,641,564
Local Spending	$23,316,729
Other Annual Costs	$682,174,806
Local Spending	$958,994
Debt Payments	$0
Property Taxes	$0

Figure 5: Input-Output Local Economic Impacts Summary Results

Local Economic Impacts - Summary Results

During construction and installation period	Jobs	Earnings ($000 (2010))	Output ($000 (2010))
Project Development and Onsite Labor Impacts [?]			
Construction and Installation Labor	8,322.1	$580,485.10	
Construction and Installation Related Services [?]	12,377.6	$577,084.93	
Subtotal	20,699.7	$1,157,570.02	$2,001,643.16
Module and Supply Chain Impacts [?]			
Manufacturing Impacts	0.0	$0.00	$0.00
Trade (Wholesale and Retail)	5,094.8	$312,038.66	$940,936.18
Finance, Insurance and Real Estate	0.0	$0.00	$0.00
Professional Services	3,756.0	$184,633.63	$624,345.58
Other Services	5,794.7	$412,494.71	$1,428,986.79
Other Sectors	8,225.5	$290,955.42	$687,877.82
Subtotal	22,871.0	$1,200,122.43	$3,682,146.37
Induced Impacts [?]	15,771.0	$700,230.32	$2,487,656.11
Total Impacts	**59,341.6**	**$3,057,922.77**	**$8,171,445.64**

During operating years	Annual Jobs	Annual Earnings ($000 (2010))	Annual Output ($000 (2010))
Onsite Labor Impacts [?]			
PV Project Labor Only [?]	201.0	$13,019.53	$13,019.53
Local Revenue and Supply Chain Impacts [?]	85.6	$4,985.84	$16,300.09
Induced Impacts [?]	70.5	$3,129.50	$11,119.77
Total Impacts	**357.0**	**$21,134.88**	**$40,439.39**

Notes: Earnings and Output values are thousands of dollars in year dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.

Result Interpretation

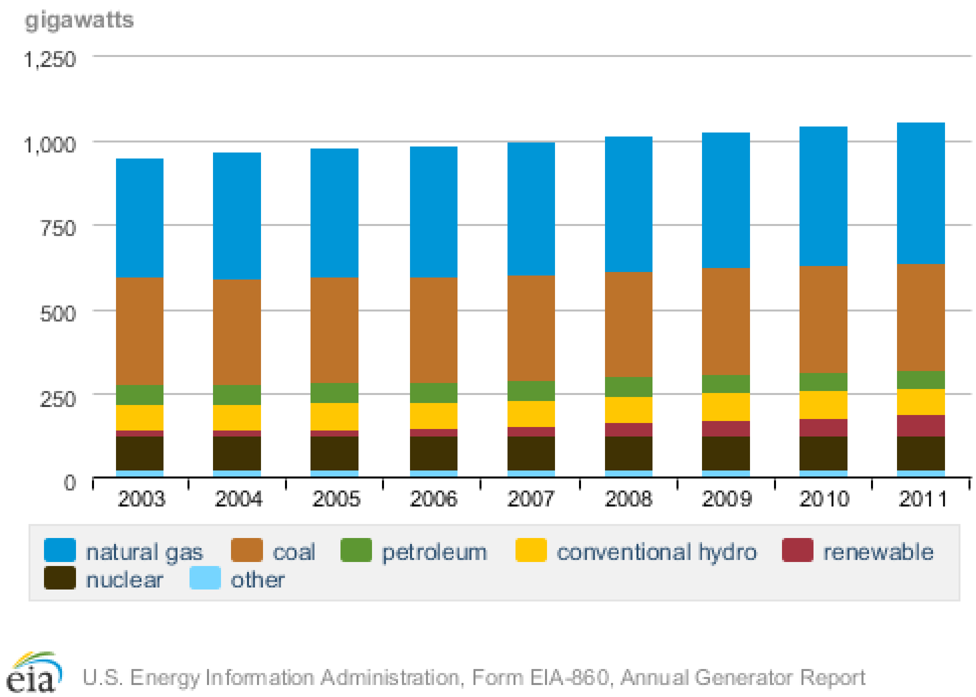
As can be seen from the model result (Figure 5) computed for California's NSHP Program (Figures 3 and 4), economic activity in input-output models is typically assessed in two major categories. First, on-site labor and professional services results, such as dollars spent on labor by companies engaged in development, on-site construction, and operation of power generation and transmission. Second, local revenues and supply chain results, which occur in supporting industries, including construction material and component suppliers, analysts and attorneys who assess the project feasibility and negotiate contract agreements, banks financing the projects, all equipment manufacturers, and manufacturers of replacement and repair parts.

It is estimated that expenditures on these projects supported around 59,000-60,000 direct and indirect jobs annually during the design, development, construction, and installation of the systems. These projects supported around $3 per year in earnings and $8 million per year in economic output. During the operational phase, these projects are estimated to continue to support 357 direct and indirect jobs, approximately $21,000 in earnings, and $40,440 in economic output annually for the lifetime of the projects (generally 20 –30 years).

The PV Industry from 2006—2013: Exponential Growth

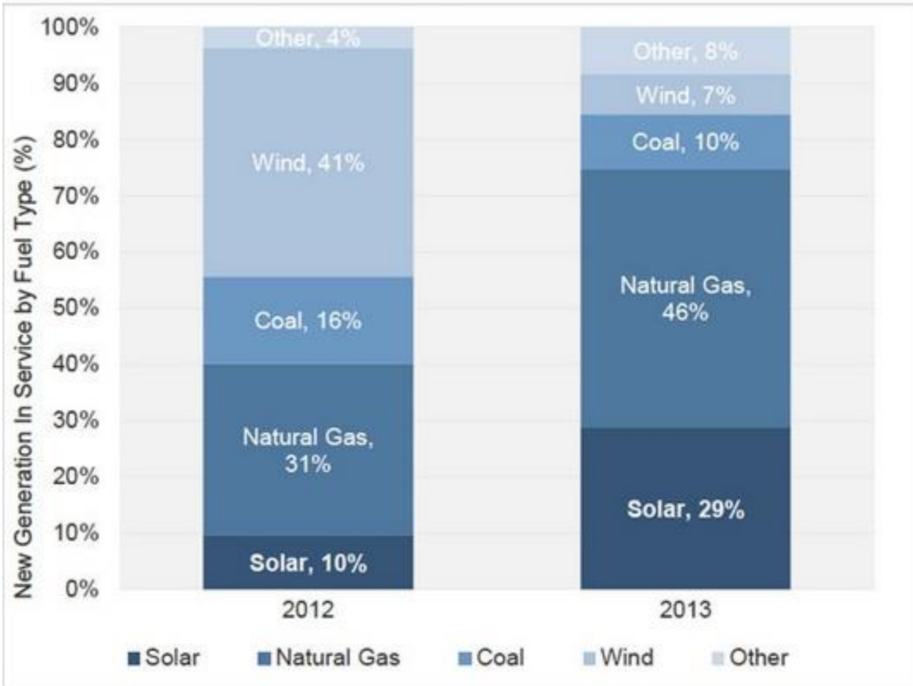
The power grid in the United States has an electricity generation capacity of over 1,000 Gigawatts. PV accounts for about 13,000 MW, representing around 1% of total U.S. generation capacity.[1] Distributed PV accounts for about two thirds of all PV capacity. PV is therefore still plays only a marginal role in overall generation capacity and is still dwarfed even by wind generation capacity, which stands at approximately 60 GW of capacity.[25]

Figure 6: Total U.S. Net Summer Electricity Capacity by Fuel Type, 2003-2011



However, PV is growing at the fastest rate of any resource in relative terms and even in absolute terms rivals natural gas capacity additions, as Figure 6 shows. In the first quarter of 2013, PV even accounted for 49% of all generation capacity installed in the U.S. Some experts predict that solar will be second only to natural gas in new capacity installed in 2013 and could be first by 2016.[26] A large proportion of PV demand comes from residential customers; their PV installations increased 53% in the first quarter of 2013 over the first quarter in 2012. The Solar Energy Industry Association (SEIA) predicts that the solar market will continue to be driven by gains in the distributed PV residential segments over the next few years.[27] In short, even though distributed PV currently accounts only for a tiny fraction of total electric generation capacity, it is growing exponentially.

Figure 7: New U.S. Power Generation Capacity by Fuel Type [28]



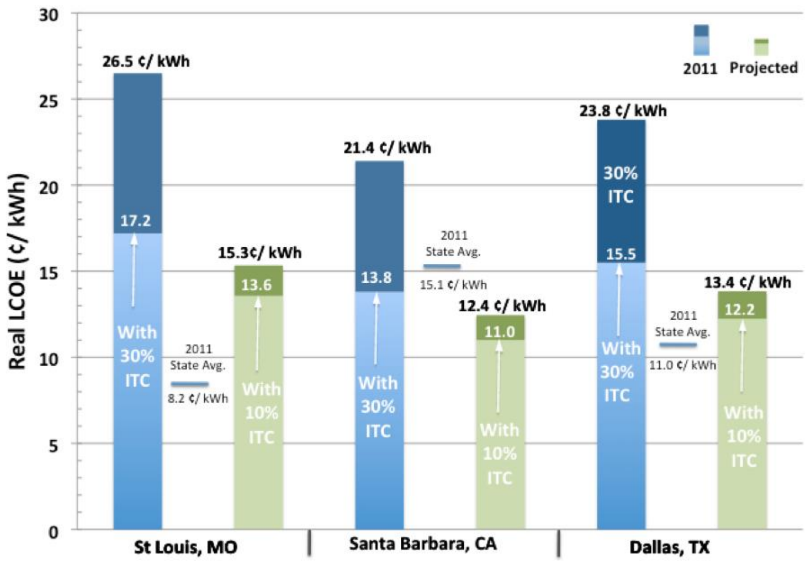
Drivers of the Growth

The main factors fueling the expansion of distributed PV are drastic system cost decreases, new distributed PV financing models, and supportive public policies.

Falling System Costs

PV costs have fallen steadily over the past three decades. Between 1977 and 2013, the price per watt of crystalline silicon photovoltaic cells dropped by a factor of 100.[29] More recently, solar panel module costs fell 40% in 2012 from $.96/watt to $.86.watt while polysilicon costs fell from $32/lb to $20/lb over the same period, a 60% drop.[30] These cost reductions have dramatically improved the attractiveness of installing solar PV for businesses and consumers. Figure 8 highlights the dramatic projected decrease in average per-kWh distributed PV costs for three U.S. jurisdictions in terms of the levelized cost of energy (LCOE), the price at which the energy from the system must be sold in order to break even.

Figure 8: LCOE for Residential PV, 2011 vs. 2013 Projected[31]



New Distributed PV Financing Models

Innovations in business models, particularly in financing, have facilitated sales to residential and commercial customers. The power purchase agreement (PPA) is perhaps the best example. Under a PPA, a solar provider owns, operates, and maintains a solar installation while their customer provides the physical location for the installation and agrees to buy the energy it produces. This structure provides a stable price of energy to customers with no upfront cost and enables solar providers to monetize tax benefits and other incentives.[32]

Supportive Public Policies

For reasons described further below, many policymakers on the local, state and federal level have put in place a number of policies that directly or indirectly create strong incentives for distributed PV. The main policies are, on the federal level, the solar Investment Tax Credit and accelerated depreciation, and on the state level, Renewable Portfolio Standards and Net Energy Metering.

Investment Tax Credit (ITC)

The Investment Tax Credit is part of the Energy Policy Act of 2005. The solar ITC went into effect January 1, 2006 and was extended through 2016 by the U.S. Emergency Economic Stabilization Act of 2008. It gives a tax credit worth 30% of the cost of a solar project to a corporation or individual investing in that project.[33] The ITC offsets part of the cost of distributed PV and lowers the project's levelized cost of electricity. Besides the federal ITC, many states also offer a variety of tax incentives which include state tax credits, property tax incentives, and tax rebates. For example, New Mexico and a number of U.S. states have made solar energy systems exempt from property tax assessments.[34] Proponents of increased PV adoption claim the ITC has fueled growth in solar installations, increased solar manufacturing capacity in the US, and lowered the cost of solar energy to consumers.[33] Critics of the ITC believe the ITC and other federal and state tax incentives for PV represent unfair government subsidies to distributed PV systems.

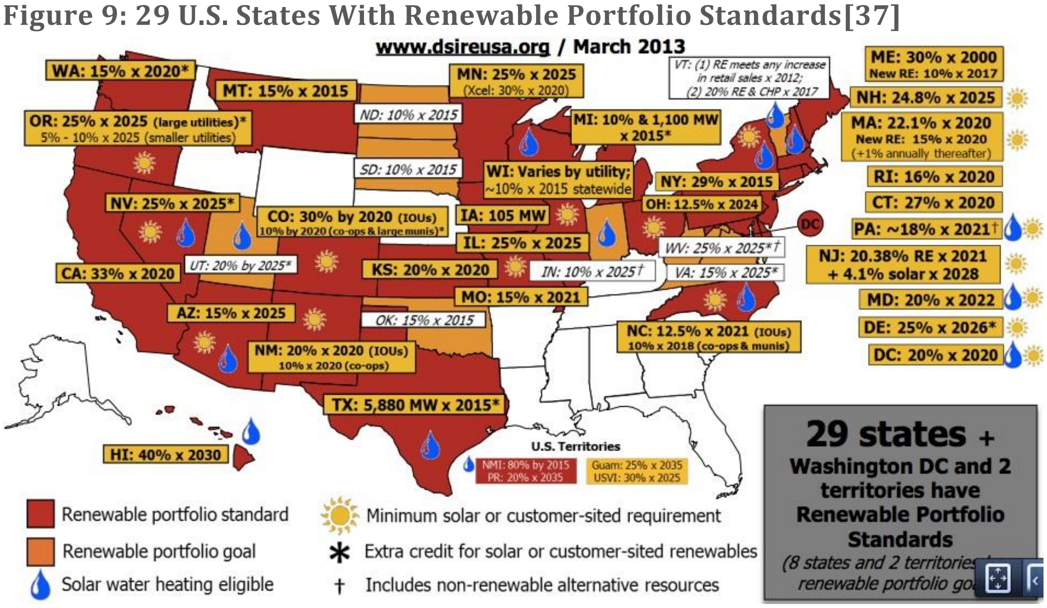
Accelerated Depreciation

Federal law allows the owner of a solar project to depreciate it under an accelerated schedule—the modified advanced cost recovery schedule (MACRS) – which allows 50% of the value of the asset to be depreciated in first year of operation.[35] Similar to the ITC, MACRS lowers the levelized cost of electricity by offering tax benefits to investors in solar projects, which has the effect of making such projects more attractive to investors.

Renewable Portfolio Standards

A Renewable Portfolio Standard (RPS) is a state-level policy, which in many cases indirectly drives the adoption of distributed solar. RPS require a minimum level of electricity to be generated by specified renewable technologies within a given time period. The standards differ by state, but 29 states and the District of Columbia currently have an RPS, while 8 states have Renewable Portfolio Goals that are not legally enforced.[34] For example, New York has an RPS target of 29% by the year 2015, while Arizona's RPS is 15% by 2025. There is no federal standard, but federal agencies have been mandated to increase their share of renewable energy to 7.5% of an agency's annual energy usage, which has led to a large increase in the purchase of renewable energy credits (RECs) by the agencies.[36]

Figure 9: 29 U.S. States With Renewable Portfolio Standards[37]



While RPS do not necessarily require distributed energy resources, some states do specify a minimum level of distributed resources through a provision known as a carve-out. According to the Database of State Incentives for Renewables & Efficiency (DSIRE) 16 states plus the District of Columbia have solar or distributed generation RPS provisions.[34] Solar carve-outs could be PV systems distributed across rooftops, or large centralized installations that would not be defined as distributed. On the other hand, while “distributed renewable generation” is most likely solar technology, there are other technologies that may qualify, such as distributed wind, micro hydro, biomass, and geothermal. Also, states can choose to designate whether owners of distributed resources may or may not be third parties or utility companies. Ultimately, carve-out requirements for distributed generation vary from state to state.

Net Metering

Net metering is a billing mechanism for utility customers with distributed PV generation that enables them to receive credit on their utility bill for the excess electricity they feed into the distribution grid. Simplified, net metering essentially means that the customer’s meter is read “net of the customer’s own generation”, although technically, electricity generated for on-site consumption and not distributed through the grid is generally excluded or tabulated separately.[38] Net metering is hotly debated across the utility, policy, and solar advocacy landscape. Given that it is one of the key policy levers in the hands of state regulators, net metering is a focal point of this paper.

Figure 10: Factors Driving Distributed PV in High Penetration States [34, 39]

State	Average Solar Radiation (kWh/m2/day)	Average Price of Electricity ($)	Net Metering Individual Systems Capacity Limit (kW)	Renewable Portfolio Standard (% of load)	Distributed PV Carve-out (% of load, target year)
AZ	6-7	$0.11	No Limit	15% x 2025	4.5% x 2025
CA	5-6	$0.15	1,000	33% x 2020	-
MA	4-5	$0.15	10,000	22.1% x 2020	400 MW x 2020
NJ	4-5	$0.16	No Limit	20.4% x 2021	4.1% x 2028
NY	4-5	$0.18	2,000	29% x 2015	0.4% x 2015

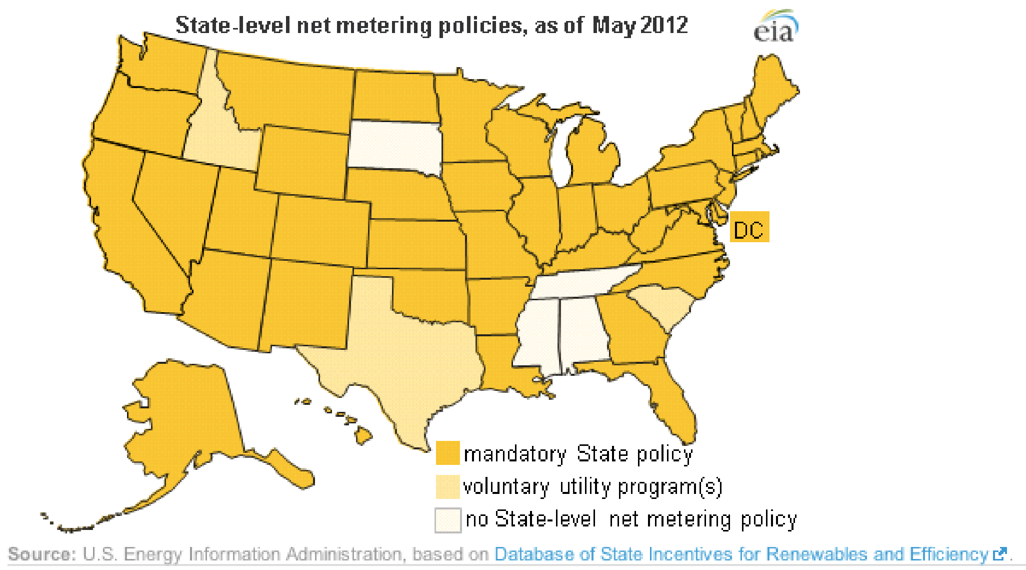
Net Metering in Detail

Net metering has played a crucial role in the growth of distributed PV. According to SEIA’s 2013 quarterly report on the industry, “whereas residential and commercial solar markets have historically been effectively capped by the availability of state- and utility-level incentives, [PV] has now become cost-effective in some markets with only the federal investment tax credit (ITC), accelerated depreciation and net metering.”[27]

Net Metering Trends

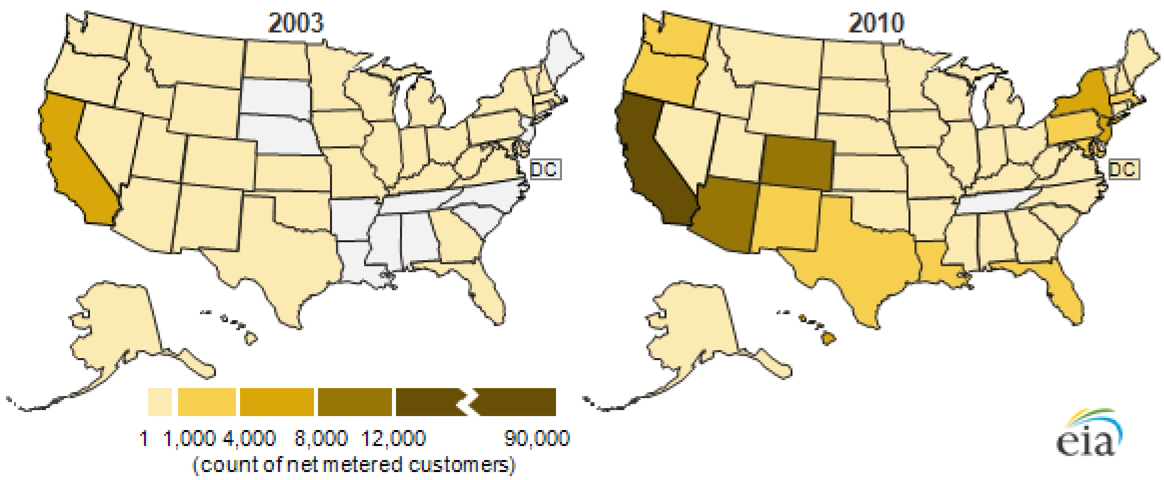
Currently, as depicted in Figure 11, 46 U.S. states have some form of net metering policy, 43 of which are mandatory policies—that is, utilities operating within those states must allow some amount of net metering within their respective service areas.

Figure 11: Prevalence of State-level Net Metering Policies[40]



The number of U.S. utility customers enrolled in net metering programs has increased significantly, especially in Western U.S. states, as depicted in Figure 12. Current data suggest that in the states with higher penetrations of distributed PV and net metering, the large majority of net metering customers have PV. For instance, Vermont reports that over 87% of the state's net metering customers own PV systems.[41]

Figure 12: Increasing Number of Net Metered Customers in U.S.[42]



Variations in Net Metering Rules

States' net metering policies may vary in several ways, which, depending on the language of a particular net metering policy, can serve to incentivize or alternatively cap distributed PV adoption. According to the EIA, net metering policies vary along five primary dimensions: technology and fuel; aggregate capacity; capacity limits; size or type of power provider; and compensation.[43] In particular, capacity limits—the maximum size of distributed PV systems eligible to enroll in net metering—vary widely between states' net metering policies.

The Key Issue: Net Metering Compensation Rates

A central point of contention between utilities, public utility commissions, PV proponents, and other stakeholders is what rate distributed PV owners should be paid for the electricity they generate. In most net metering systems, utilities are required to credit net metering customers at the retail rate, which is the standard electricity price that a customer would normally be charged for purchasing electricity from the utility. However, there are three possible approaches for net metering reimbursement rates: besides the retail rate, there are also the wholesale rate and value-based rates.

Retail Rate

The simplest and most prevalent net metering reimbursement structure requires the utility to reimburse net metering customers at the retail rate the utility would otherwise sell electricity. The "math" of net metering customer reimbursement is the easiest when the price paid for a kilowatt-hour generated and exported to the grid is the same price a customer pays for a kilowatt-hour (kWh) consumed. However, conferring a retail rate to distributed generation implies that the value of every unit of energy generated is exactly equivalent to the cost of a unit of grid-supplied energy. But in many cases, the retail rate is higher than the cost the utility otherwise would have paid. Instead of paying less for power on the wholesale market or procuring it from its own generation fleet, the utility pays the customer the full retail rate.

Wholesale Market Rate

In deregulated electricity markets, electricity is typically purchased and sold on a wholesale market in most regions of the United States. Wholesale electricity prices correspond to the demand relative to supply at a specific location. In theory net metering prices could be based on these wholesale prices (which are also referred to as the Locational Marginal Price or LMP) because utilities purchase electricity from the wholesale market before distributing it to end users at the retail price. However, special state or federal level regulations would have to be crafted to allow wholesale net metering pricing on a wide scale.

Value-based Rates

Value-based rates are a new approach currently being tested by the municipal utility in Austin, Texas, Austin Energy, and the state of Minnesota. The idea behind value-based rates is to tie the net metering price paid for electricity generated by distributed resources to the estimated value that the resource provides to the grid.[44] Distributed resources, especially PV, provide a number of challenges and benefits for the grid. On one hand, distributed PV incurs certain integration costs, because the distribution grid was historically built to carry electricity only one way, from the utility's generators to the customer. On the other hand, distributed PV also provides benefits, such as reducing the need of the utility to burn fuel for energy production and potentially avoiding transmission and capacity investments.

Evaluation of Net Metering Policies

Most current net metering policies use a set of basic methods to value and compensate distributed PV owners for their electricity generation. These methods are rooted in a system of centralized generation and do not translate well to pricing distributed generation. For instance, when PV customers are reimbursed at the retail rate, they may be overcompensated for the value of their electricity because the retail rate often already includes the customer's portion of utility fixed costs associated with electricity generation. Similarly, in instances where net metering customers are reimbursed at wholesale rates, which are generally far lower than retail rates, they are likely undercompensated for the benefits their solar PV generation provides to the electricity grid because the price does not take into account benefits distributed PV confers, such as avoiding transmission and capacity investments. In contrast, value-based rates can be set in an economically efficient fashion that reflects the full spectrum of benefits distributed PV provides; however, there is wide disagreement what this economically efficient value would be. Agreeing on a methodology for pricing solar PV is an important next step in solar regulation, and we address it later in this paper.

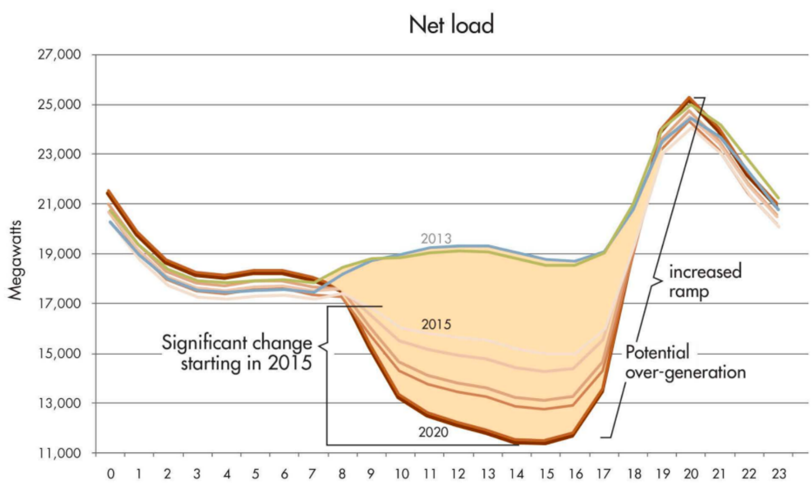
The Problems Distributed PV Poses for the Traditional Utility Model

Electricity tariffs historically designate most costs for residential customers to be recovered through volumetric rates. Increased distributed PV penetration throughout the grid is problematic for the traditional utility cost-recovery structure. The problem arises from net metered customers, the payments and credits offset the volumetric charges and reduce revenue intended to pay for the customer's cost to access the grid. Ultimately, this issue stems from the design of net metering rates that prices distributed PV services equal to retail rates. As a result, many net metering customers pay little or nothing for the services provided by the grid. This section provides insight from the telecommunications industry and the effects of a disruptive technology on a traditionally regulated natural monopoly. Additional lessons can be inferred from the Californian and German electric sector.

Utility Challenges

California's Independent System Operator (CAISO) is forecasting partial peak shaving as more renewables are brought online, as seen in Figure 12. The chart shows the net load CAISO's central thermal power plants would need to supply when you combine hour-by-hour expected customer electricity demand with the offsetting output from variable renewables over the course of a typical day. The curve shifts as growing shares of renewable generation are added to the grid, with the evening ramp up steadily increasing each year. The result is a large evening ramp up of dispatchable power plants that are idle during daytime hours. It shows that CAISO will soon face challenges in managing the grid.

Figure 13: CAISO Net Load - 2012 through 2020 [45]



In many ways Germany can be viewed as a cautionary scenario. Germany possesses high penetrations of renewables with legal priority over fossil fuels. This caused German wholesale market prices to decrease and sometimes go negative.[4] Owners of traditional fossil fuel power plants are finding it challenging to turn a profit and this has impacted utilities' credit quality by exposing investors to increased uncertainty and risk. The decline in credit quality led to a higher cost of capital, putting further pressure on customer rates. With lower penetrations of distributed renewables and less aggressive promotion laws, the U.S. power sector has yet to face the same kind of downward spiral. Yet, there is concern that the same forces driving change in Europe are starting to appear within the US utility sector.

Provided fixed costs are paid for through volumetric charges, it follows those customers with distributed PV pay a lower proportion of the overall fixed costs associated with delivery electricity to the utilities service area. When utilities cannot cut costs, they will have to distribute costs over fewer and fewer customers. Utilities' current rate structure and the lack of a clearly delineated distributed PV fee for accessing the grid has the potential to put their revenues at risk in the context of increasing distributed PV penetration throughout the grid. The utility pricing model of recovering fixed costs through volumetric charges and utilities' mandated role as "obligation to serve" limits their range of strategic responses to potential increases in the penetration of distributed PV. The result of depressed revenues and static fixed cost are higher electricity prices that encourage a higher rate of distributed PV installations.

Telecommunications

The telecommunication sector grappled with similar issues during its own deregulation. Similar to the challenge posed to the utility industry by distributed PV, the adoption of disruptive technology, including voice over internet services and mobile devices, created a threat to landline revenues. The rising number of customers who opt out of landline service left a shrinking share of customers to pay for infrastructure maintenance and expansion. This led to higher service costs for remaining landline users, which in turn will lead to more customers canceling or going without landline service to avoid the increasing prices. It was estimated that 36 percent of U.S. households were wireless-only subscribers in 2012.[46] This scenario is analogous to the adoption of distributed PV technology in the electricity market. Since then telecoms have adapted by cutting services, merging markets, and developing alternative revenue streams.

A local telephone company's costs include constructing and maintaining telephone lines and equipment costs as well as subsidizing system access for customers.[47] The subsidization scheme ensures a consistent tariff across varying infrastructure costs and provides reduced rates for low-income customers. Entrant offering mobile and internet substitutes took away the most profitable customers by focusing on densely populated areas. Under the obligation to serve, the incumbent telecoms are still required to provide landline service to all markets. The new offerings are not bound by the same requirement. Some rural areas still lack access to broadband and cell-phone service.

A Bernstein Research analyst calculated that AT&T and Verizon's landline businesses generate more than 50% of revenues, but an even higher share of costs.[48] The two firms have already cut thousands of jobs to cut costs as the high fixed cost of running the network is spread over an ever smaller number of customers. Telecoms decreased services to landline customers by ending printed phone books, renting phones, rural copper lines. It also led to higher bills for captive customers such as businesses with switchboards, which cannot do away with their landlines.

Responding to the threat of new competitors, many of the larger telecommunication companies have been able to provide their own wireless or internet based alternatives. These new technologies have created new revenue streams that in some cases have been used to subsidize the landline infrastructure. Smaller telecoms have been forced to merge or be acquired. Revenues from new services would then be used to keep an obsolete infrastructure alive. It is unclear if utilities can mimic the telecom industry by providing add-on services. Telecom companies were able to offer value-add services but electric utilities don’t have any clear equivalents as electricity delivery still relies on the grid.

Existing Theoretical and Practical Attempts to Solve the Problem

As the experience of the telecommunications sector illustrates, the utility industry faces issues that aren't unprecedented, and theoretical approaches as well as existing state-level policies have been suggested or implemented to tackle the problem. The approaches we consider most relevant target the question of how grid access and distributed PV should be valued.

Valuing Grid Access

This section details the value of the grid to distributed PV customers and provides an economic framework for pricing power generated by distributed PV customers. Arizona and California introduced laws that would support grid maintenance by including minimum charges on customer's bills.

With growing distributed PV adoption, the electricity industry is now entering a similar period of disruptive technology that the telecom industry faced a decade ago. Utilities are subject to the same universal access requirement and new entrants – including distributed solar – are cutting into utilities' revenues. In short, an outcome much the same as in telecom, where an electrical divide arises between those with and without the ability to access new electric services, is possible. In addition, regulated utilities' tariffs are frozen for defined periods of time, sometimes years. Unlike the telecom industry substitutes, distributed PV customers still require the use of the electric grid.

For most of the lifetime of the grid these services were part of the electricity tariffs. It is now possible with distributed PV to use these services daily but not contribute to their maintenance. Customers connected to the grid have their system frequency and voltage controlled by real time balance between system demand and total generation.[49] Without this the household could experience flickering lights and brownout or have to maintain costly balancing equipment. Another service the grid provides is connecting sellers to buyers. With variable power sources, excess generation is common and grid acts as an instantaneous marketplace. Perhaps the greatest value of the grid is its ability to reliably provide backup services in times of maintenance or prolonged overcast conditions.

Currently net metering policies create a situation where customers receive the full value of the grid but don't pay to maintain it. As a result, many electric utilities are pushing policies that rein in lost revenues. In Arizona, regulators voted in November to allow the largest utility to tack a monthly fee of $5 onto the bill of customers with new solar installations. Arizona Public Service originally sought a $50 surcharge. Colorado's utility commission is considering a proposal to halve credits for solar energy households. Other states, including Louisiana and Colorado, are also contemplating changes in net metering rates. A key challenge is designing a tariff that fairly covers the fixed costs to serve distributed PV owning customers while not being prohibitive to new PV adoption.

The Efficient Component Price Rule

In industries like electric utilities and telecoms, it is often necessary for the regulator to set the prices to be paid for use of shared services like access to the telecommunications network or electric grid. These prices are sometimes referred to as access charges, and they help achieve a number of objectives. For example, they encourage downstream entry and upstream bypass, and encourage efficient capital investment and utilization. Different methods were developed to price access to the incumbent-maintained network. There is a consensus among economists and regulators that interconnection prices based on cost are most likely to lead to desirable outcomes. One leading economic basis for renovating tariffs is the efficient component pricing rule (ECPR), also called the Baumol-Willig rule.[50, 51] Under this approach, the value of the grid is the marginal cost of taking on the new business plus the likely reduction in the incumbent's profits as a result of losing business to the new entrant - which is the same as the incumbent's final product price less the costs it would avoid by providing access. The incumbent thus recovers all common and fixed costs, as well as a return on capital.[52] Adopting ECPR does not require a change in regulated prices of final services and does not interfere with “obligation to serve” policies.

As with all solutions identified, ECPR has its drawbacks in the absence of strong regulation. The incumbent makes the same profit regardless of whether the new entrant enters the market or not. The downstream services of incumbent and entrants must be perfect substitutes. Also, whatever inefficiencies are present in the retail price are preserved in the access price. The key advantage of ECPR is that the policy avoids foreclosure and leads to better results than other access regulation, such as cost based, in terms of investment level and consumer surplus.[53] Overall, the ECPR acts as framework for utilities to value access to the grid.

Allocative efficiency requires that resources, products, and services are allocated to the person or persons who value them the most. For this to happen, consumers of final products or services (such as telephone calls to other customers) should pay prices that reflect the cost of the resources used to provide those products or services. In the power generation industry, independent power producers earn wholesale prices. A wholesale electricity market exists when competing generators offer their electricity output to utilities. ECPR would value distributed PV-generated power the same as any other independently produced power. In this scenario, utilities would lose less revenue from distributed PV adoption because competition keeps the average wholesale price of electricity below retail rate. During peak demand wholesale prices can rise above retail rates. Solar energy is generated during peak times but the match is not perfect. Cost-based solutions and wholesale pricing make sense in the utility space because the grid is still maintained regardless of who generates power.

Practical Attempts to Value Grid Access

As a contrast to the more theoretical approach of the Efficient Component Pricing Rule, below are two examples of how the value of grid access has been set in two case studies in Arizona and in California.

Arizona: APS SOLAR ACCESS FEE CASE

On November 14, 2013, the Arizona Corporation Commission ruled that all Arizona Public Service customers who install solar panels after January 1, 2014 will pay a monthly charge of $.70/kW of installed capacity. The fee amounts to approximately $4.90/month for the average residential system of 7kW.[54]

Negotiations included representatives from APS, the Residential Utility Consumer Office (RUCO), Arizona's ratepayer advocate, and regulators. Solar industry stakeholders also commented ton proceedings. After initially seeking a monthly charge of $50-$100, APS reduced their recommendation to $8 per kW. RUCO and the Commission's staff recommended bill charges in the $3.00 per kilowatt range. In final negotiations, commissioners narrowed the surcharge options to $1 and $.70 per kW charge, a position supported by solar representatives and RUCO.[55]

Representatives from both the solar industry and APS commented on the outcome. Bryan Miller, a VP at Sunrun and the President of The Alliance for Solar Choice, stated, "A $0.70 per kilowatt charge will hamper the industry. We cannot sustain a $1.00 per kilowatt charge."[56] When asked if the new fees would hinder the solar industry in Arizona, Solar Energy Industries Association (SEIA) Counsel Court Rich said, "You do the math," referring to the fact that solar leasing programs usually save customers $5-10 per month.[56] Don Brandt, APS Chairman, President and CEO, was similarly dissatisfied. "The Arizona Corporation Commission has taken an important step in reforming the state's net metering policy. The ACC determined that net metering creates a cost shift. We applaud the ACC for cutting through the rhetoric and focusing on how the cost shift impacts non-solar customers. Of course, having determined that a problem exists, we would have preferred for the ACC to fix it. The proposal adopted by the ACC, and surprisingly championed by the state's consumer advocate RUCO, falls well short of protecting the interests of the one million residential customers who do not have solar panels. We will continue to advocate forcefully for the best interests of our customers and for a sustainable solar policy for Arizona."[54]

California: AB 327 CASE STUDY

On Monday, Oct 7, 2013, Governor Jerry Brown signed into law Assembly Bill (AB) 327. The bill's main provision allows the California Public Utilities Commission (CPUC) to simplify the rate structure for residential electricity consumers, eliminating some rate "tiers" that charge customers more as their energy usage increases. The goal of a new system would be reduce the amount that heavy energy users pay on their monthly utility bills. The bill also allows the CPUC to charge residential customers a flat fee of up to $10 to cover the fixed costs of maintaining the grid. Additional provisions make changes to the state's net metering laws that eliminate short-term uncertainty by extending the expiration date of net metering laws and establishing a pathway to lifting the cap on total net-metered capacity in the state's three largest IOUs. Both the changes and rate structure and the new fixed fee have implications for the solar industry; our analysis focuses on the first change, the fixed customer fee.

The bill was originally intended to lower summer home-cooling costs for residents of the Central Valley of California by changing the electricity rate structure for residential customers; however the bill – as initially written – had negative ramifications for the solar industry and precipitated intense negotiations. Both the proposed changes to rate structure and the proposed flat fee to cover the cost of grid maintenance upset solar advocacy groups, state politicians, environmentalists and groups representing low-income California residents. Sides reached a compromise by adding provisions to significantly alter the state's rules on net metering. The compromise satisfied many groups that previously opposed AB 327, including the national Solar Energy Industries Association (SEIA), The Alliance for Solar Choice (TASC), and the nonprofit group VoteSolar, and they ultimately shifted their positions to support the bill. Just before its passage, Bryan Miller, vice president of public policy for third-party solar provider Sunrun, said, "[AB 327] is going to have an enormous impact in helping the renewable industry grow… It removes mountains of uncertainty in current law about how the rules going forward for net metering will work and be implemented."[57]

Valuing Solar Electricity

Why Valuation Is Important

There is no consensus on what the impact of a shift towards more distributed PV generation would mean. The perception of the costs and benefits of distributed PV in the power industry ranges from offering a highly desirable solution for environmental and reliability problems to posing a highly cost-inefficient hazard to the stability of the grid. This range of views is also reflected in systematic studies on the costs and benefits of distributed PV. To cite but one example, two recent studies estimated the benefits of distributed PV, with one arriving at approximately three cents per kWh and the other at approximately 22 cents per kWh. Both studies evaluated the same state in the same year, but evidently used different approaches to calculate the effective value of distributed PV.

If regulators wish to set the compensation awarded to owners of distributed PV at the level of the benefit they actually provide to society, they need to rely on a valuation approach that is objective and comprehensive. Regulators must therefore decide what categories of costs and benefits should be examined, and what methodology should be used to quantify the net value in each category. Such a valuation approach is crucial to any balanced policy on distributed PV.

Existing Value of Solar (VOS) Policies

Replacing net metering with a Value-of-Solar (VOS) approach is a recent innovation in utility regulation and as of 2014, only two practical examples have been adopted. The City of Austin pioneered VOS in 2012, and in 2014 Minnesota was the first to introduce VOS on a state level.

Austin Energy VOS

In 2012, Austin Energy ("Austin"), a municipal utility serving approximately 420,000 customers throughout Austin Texas, became the first utility in the U.S. to introduce a Value of Solar tariff (VOS) to replace traditional net metering. According to Austin, the VOS was introduced to address the problem that traditional net metering customer-credited rates "did not necessarily represent and likely under-represented the full value of distributed PV generation."[58]

Under Austin's approach, a VOS credit is calculated and tracked separately from the home's standard electricity meter, and is then applied to the customer's monthly electric bill. Austin's VOS is calculated using an algorithm originally developed by Clean Power Research. Austin's distributed PV valuation figure is updated annually, and customers with a VOS contract subsequently have their VOS adjusted each year. According to Austin, this annual readjustment of the VOS prevents over- or under-payment as the utility's costs change.[59]

Austin's 2012-2013 VOS credit was set at $0.128 per kWh, applicable to distributed PV systems of 20 kW or less. This VOS rate was higher than the coincidental top-tier on-peak rate of $0.114 per kWh. Austin's VOS also includes a fixed customer charge of $10 per-month and peak season rates during which prices are higher than off-peak rates. Austin's VOS credits roll over for customers each month until year-end, at which point any carry-over credits are reset to zero.

Austin's VOS currently accounts for the following components to value distributed PV:

- Avoided fuel costs, valued at the marginal costs of the displaced energy
- Avoided capital cost of installing new power generation due to the added capacity of the PV PV system
- Avoided transmission and distribution expenses
- Line loss savings
- Fuel price hedge value
- Environmental benefits, calculated as: PV output times REC price

In adopting the VOS policy, Austin cited as benefits: 1) decoupling distributed PV value from consumption charges; and 2) reducing various customer class subsidies. Austin cited complex stakeholder process and customer confusion in understanding the VOS as key hurdles during its adoption process.

In December 2013, Austin announced the VOS would be reduced from $0.128 per-kWh to $0.107 per-kWh. This VOS reduction was due in large part to the reduced value of energy, driven by lower forward market prices for natural gas.[60]

Minnesota VOS

In 2013, Minnesota passed a new solar energy standard which included the adoption of a VOS. The new law establishes the VOS as an alternative to the state's existing net metering laws. For PV systems less than 1,000 kW, investor-owned utilities must either compensate PV generation at the average retail per-kWh rate or may apply for a VOS tariff, based on a VOS calculation methodology, which (as of February 2014) was in the final stages of being approved by the state PUC. The VOS methodology may also be applied to the rate used for community solar gardens throughout the state.

According to the new law, Minnesota's VOS methodology "must include the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution losses, and environmental value."[61] Similar to Austin's VOS methodology, the price will adjust annually, and solar producers will separately purchase electricity at their normal applicable rate and will sell electricity using the VOS-determined rate. Also, monthly credits that exceed electricity usage costs can carry over for up to one year before being reset to zero; the VOS does not allow a net payment to the PV owner, only electricity bill credits. Dissimilar to Austin's VOS, Minnesota solar producers will lock-in the production price through a 20-year contract when their solar producing facility comes online.[62] Minnesota's VOS tariff is also required to include a mechanism for utilities to recover the costs to serve customers within the VOS class, which should help avoid shifting fixed costs to other customer classes.

According to the VOS proposed in January 2013 in a report generated by Clean Power Research for the Minnesota Department of Commerce, key aspects of the methodology include:[63]

- A standard PV rating convention
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin
- Requirements for calculating the electricity losses of the transmission and distribution systems

- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

In addition to establishing a VOS, Minnesota's new solar energy standard also mandates a 1.5% solar standard for the state's IOUs, in addition to the states existing 25% by 2025 renewable energy standard. The law also creates a $5 million incentive pool for solar projects less than 20 kW, increases the net metering limit from 40 kW to 1,000 kW per installation for IOUs, limits the cumulative net-metered generation to 4% of each public utility's annual electricity sales, and authorizes community solar gardens throughout the state.

Criticism of VOS Tariffs

Despite the attempt to comprehensively value solar through VOS tariffs, the method has been criticized from both solar enthusiasts and skeptics, in Minnesota and elsewhere. Some PV advocates have stated that VOS rules replace the freedom of net metering with further dependence on the utility's monopoly, because a PV owner would be required to sell their energy to the utility at the VOS rate and purchase all electricity at the retail rate, instead of consuming their own electricity whenever they generate it at the same retail rate the customer normally pays. PV advocates also point out that the Austin and Minnesota VOS policies provide for periodic adjustments of the VOS by the utility or the regulator; while the VOS rate is above the retail rate in both Austin and Minnesota in 2014, utilities would likely prefer to use the adjustments to eventually set the rate below the average retail rate. In this case, owners of distributed PV would be compensated less than under current net metering practices.

Furthermore, Anne Smart, the Executive Director of the Alliance for Solar Choice, a solar advocacy group, criticizes VOS tariffs as "Value of Solar Taxes",[64] referring to an opinion that partners at the law firm Skadden, Arps, Slate, Meagher & Flom LLP filed with the Arizona Corporation Commission. This opinion alleges that in contrast to net metering, the payments that owners of distributed PV will receive under a VOS tariff will constitute taxable income; this would increase the tax obligations of that PV owner and restrict their eligibility for the renewable income tax credit on the cost of their PV system. This is not true in the case of Austin's and Minnesota's VOS tariffs, as these only provide electricity bill credits, not payments above the customer's electricity costs.

Criticisms to VOS tariffs have also been voiced by utilities and some consumer advocates concerning the risk of cost shifting (as explained in detail in the "Rate Structure and Cost

Recovery" section of this paper), and regarding some of the categories accounting for the value of VOS tariffs. In particular, PUCs are scrutinizing avoided costs for generation capacity, transmission and fuel, and environmental value. Regarding avoided environmental costs such as avoided CO_2 emissions, some organizations including Otter Tail Power, an investor-owned utility serving Minnesota and North and South Dakota, argue that it is inconsistent to pay distributed PV owners for emission reductions when there is currently no cost of CO_2 emissions charged to utilities, and distributed PV owners therefore don't help utilities avoid any emission cost.[65] This view was evidently not shared by Minnesota lawmakers, as the language in the 2013 VOS law regarding "environmental value" [Minnesota statute 216B.164] clearly intends for value obtained from environmental benefits to be incorporated in the VOS. In Minnesota, the cost assigned to CO_2 emissions would be based on the social cost of carbon used by federal agencies. However, distributed PV also avoids other emissions whose exact value is difficult to determine.

Recommended Approaches to Distributed PV Valuation

This paper's suggested distributed PV valuation approach draws heavily from two recent publications on valuations methodology. In first publication, a 2013 report by Rocky Mountain Institute (RMI),[66] reviewed 16 distinct distributed PV cost-benefit studies by utilities, national labs, and other organizations. RMI's showed that while the estimated value of distributed PV varied dramatically between the 16 cost-benefit studies, the categories used for valuation between these studies frequently overlapped. The second valuation publication this paper references is a practical guideline for regulators for developing a valuation methodology published in 2013 by the Interstate Renewable Energy Council (IREC).[1] Following are the approaches this paper recommends to include in the valuation of distributed PV, consisting of eight categories of costs and benefits as well as methodologies to quantify the net value in each category.

Avoided Energy Costs

Distributed PV produces electricity during periods of high demand when utilities typically either run more expensive power plants such as gas combustion turbines or combined-cycle gas turbines, or import energy on the wholesale market to meet peak demand. Distributed PV therefore offsets a part of the costs of providing energy during high demand.

In most cases, distributed PV replaces some combination of intermediate and peaking natural gas generation. In those cases, the energy value should therefore be calculated based on the avoided cost of running a gas combustion turbine or a combined-cycle gas turbine, using natural gas price forecasts.

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[1] It should be noted that IREC's valuation report was led by Karl Rábago, who was also instrumental in design of Austin and Minnesota's VOS policies.

Avoided Line Losses

According to EIA, national average electricity transmission and distribution line losses average 7% of all electricity transmitted across the U.S.[2] Localized distributed PV production and consumption reduces grid transmission and distribution losses and increases the overall efficiency of the power system. Line losses are minimized when a distributed energy source, such as distributed PV, is located in or near the end-demand site.

Line losses vary with load, meaning that the timing of load reductions from distributed PV matters. Line losses should therefore be calculated using marginal losses, not average losses. Furthermore, the valuation of avoided line losses should include both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have distributed PV.

Deferred or Avoided Capacity Additions in Generation

Distributed PV may provide capacity benefits when it results in the deferral or avoidance of central electricity generation capacity. RMI's 2013 study points out that distributed PV generation capacity value will "generally be higher if distributed PV output is more coincident with peak."[66]

There are two practical difficulties in valuing the generation capacity of distributed PV. First, the intermittency of distributed PV makes it challenging to set an appropriate capacity value. Second, the fact that a power plant has a much larger capacity than the incremental capacity additions of distributed PV raises the question at what cumulative capacity distributed PV installations actually defer a power plant. To overcome the intermittency challenge, this paper recommends considering the "effective load carrying capacity" method developed by Clean Power Research. Regarding the threshold issue, IREC's argument makes sense that any distributed PV installation, regardless of its size, immediately reduces the grid load, and thus should be valued as a fraction of the deferred generation plant from the start.

Deferred or Avoided Capacity Additions in Transmission and Distribution

Since distributed PV generally produces electricity close to demand location, it reduces the need for distribution and even transmission lines. Distributd PV also reduces the stress on grid components, which can extend the useful life of grid infrastructure and reduce maintenance costs for utilities.[4]

The extent of the T&D value offered by distributed PV depends partially on whether the utility in question is considering building transmission lines, in which case distributed PV can help defer a major expense which should be incorporated into the valuation. For the value of distribution PV capacity, valuation should distinguish between distributed PV serving residential load and distributed PV serving commercial load. Distributed PV peak energy production tends to coincide with commercial load, but not with residential load. The value of distribution capacity offered by distributed PV therefore varies from circuit to circuit.

Ancillary Services

A number of services are required to maintain the electric grid's reliability and efficiency, the collection of which is generally referred to as "ancillary services." First, energy demand and supply must be kept in almost perfect balance at all times, which requires accurate forecasting, scheduling power plants to either provide electricity or be ready to do so on short notice (spinning reserves), maintaining the voltage and the frequency within certain limits, and providing what is called reactive power. Distributed PV adds benefits and costs in all of these categories; the exception being that it can't be forecasted or scheduled as reliably as other generators.

The inverters currently used by distributed PV provide certain ancillary services, such as maintaining the output of produced electricity at a certain voltage. But if grid voltage drops below a critical threshold, these inverters are expected to disconnect the distributed PV system from the grid, which would let the voltage level of the grid drop further. For this reason, many valuation studies currently attribute no ancillary value to distributed PV. However, more advanced inverters could resolve this issue in the near future, in which case distributed PV would provide ancillary services that should be incorporated into their valuation.

Fuel Price Hedge

Prices for fossil fuels fluctuate significantly, especially for gas. If distributed PV reduces the reliance of a utility on fossil fuels, it also reduces the utility's exposure to fuel price risks. Thus, this reduction in price volatility should be accounted for in the valuation of distributed PV.

Utilities wishing to hedge against fuel price risk pay a premium to enter into long-term supply contracts; that premium is therefore the value they derive from fuel price hedging that should be used as a basis for valuing the price hedge offset component contributed by distributed PV.

Grid Reliability and Resilience Impacts

While it is apparent that distributed PV can increase the reliability and resilience of the grid, it is difficult to quantify its benefits at the grid-level. However, as pointed out in the Clean Power Research study, on the level of individual customers distributed PV's benefits can be very concrete. For example, residential customers with medical conditions may enjoy increased reliability benefits from distributed PV plus storage. At the same time, reliability and resilience benefits partially overlap with the ancillary services distributed PV provides, and should not be double-counted.

Avoided Utility Environmental Compliance Costs

As distributed PV reduces the dependence on fossil fuel of the power sector, utilities may reduce their cost of complying with RPS and emissions regulations. Regarding RPS compliance, distributed PV reduces the load of a utility, which, in most states, translates into a reduction of the renewable energy target utilities must meet. This benefit should be included in the valuation of distributed PV.

Within present emissions markets, the environmental compliance costs of utilities are currently reduced only marginally. However, there is also an element of risk hedging that distributed PV provides against state or federal policies that establish an emissions charge or increase existing charges for emissions such as NOx, SO2 and CO2. Furthermore, operating thermal plants require large amounts of water, which exposes utilities to risk from changes in weather patterns and related water regulations. Companies are incorporating the cost of regulatory uncertainty into their strategic planning, and thus it logical to include the regulatory risk hedge provided by distributed PV in its valuation.

Considerations for Future VOS Policies

While all of the above-listed categories of costs and benefits related to distributed PV should be considered, not all of them are equally important nor quantifiable. This dilemma is evident in the Minnesota VOS. In practice, many of the valuation components recommended are featured in Minnesota's VOS, but several categories have been excluded. These excluded categories include: 1) ancillary services, such as voltage control; 2) grid reliability and resilience benefits; 3) avoided utility and environmental compliance costs; and 4) certain aspects of societal benefits beyond those directly related to the environment. Minnesota's VOS explicitly references voltage control as one area that should be included in future updates to the policy, pending changes in interconnection standards and further research of methodologies to quantify both the ancillary benefits and the system integration costs of distributed PV.

As the reactions to existing VOS policies show, even a systematic valuation of distributed PV is likely to be criticized as unfairly favoring distributed PV owners by utilities, and conversely, as overly favorable to utilities by proponents of the PV industry. Regulators are therefore well-advised to involve all stakeholders in the design of a VOS policy; to follow transparent and coherent principles while designing the policy; and to be sensitive to the language and possible interpretations of VOS laws. Ultimately, all approaches to valuation of distributed PV are occurring in a rapidly changing technology and policy environment. Policymakers should account for this fluidity by giving distributed PV valuation policies the flexibility to include further categories of costs and benefits that are currently insignificant or not quantifiable, but may become so in the future.

Our Analysis

Thus far, this report has brought to light issues that regulators and lawmakers will have to consider to fairly price grid electricity and distributed PV in the future. It examines ways in which different jurisdictions have attempted to address problems that include cost shifting, lost revenue, and improper valuation of solar benefits. While many reports focus on addressing either problems that face utilities or those that face the solar industry, our objective is develop an understanding of how different policy options and choices affect both groups. This section attempts to do so by analyzing the effects of two different policy options – fixed fees for distributed PV grid access and a value of solar tariff – on both the financial health of utilities and the project-level economics of distributed PV systems. By conducting this analysis and quantifying the impact, we hope to advance the policy discussion toward outcomes that are mutually beneficial for both the solar industry and investor-owned utilities.

Methodology and Limitations of our Analysis

Our analysis models the impact of varying fixed fees and compensation for solar on utilities and distributed PV owners. The following section describes the methodology and limitations of the models we used to estimate financial impact.

Utility Rate Model

The purpose of the utility rate model is to examine the cost-shifting issue faced by utilities as distributed PV penetration increases. The model estimates how retail electricity rates might change as distributed PV penetration increases and utility revenue falls, forcing utilities to shift fixed costs onto none-PV ratepayers. Data from a major California utility is used in order to approximate this effect. Rate increases are estimated by first calculating the total amount of revenue lost to distributed PV, calculating what portion of that revenue would have been used to pay fixed costs, and distributing that stranded fixed cost distributed across the entire residential customer class as part of the per kWh energy charge.

Our analysis assumes that fixed costs cannot be shifted from one customer class to another- i.e costs associated with serving residential customers must be covered by residential customers only. Within each customer class, the following model inputs are necessary: number of customers, number of customers per rate tariff, kWh consumed, cost per kWh, fixed charges, revenue requirement allocated to that class, and proportion of kWh charges dedicated to fixed cost recovery.

The total amount of revenue the utility loses per PV customer is calculated by modeling the payouts to an average California distributed PV owner enrolled in net metering under a time of use tariff over the course of one year. Time of use (TOU) tariffs have higher rates during periods of peak consumption, which tend to coincide with peak production for distributed

PV, so a TOU tariff was used to maximize the value of a distributed PV system under net metering. Each kWh produced by the distributed PV system is assigned a value equal to that of the retail rate during the time of production. This calculation captures the revenue lost when the distributed PV owner buys from her system instead of the grid and revenue foregone because of net metering credits to the customer for electricity exported to the grid. This calculation is based on the following inputs: number of net metering installations, size of installation, kWh production of installation, and time of production.

This calculation produces a total of dollar amount of lost revenue that would have been used by the utility to recover fixed costs if not for the presence of distributed PV. To calculate the portion of that revenue that would have been used to cover fixed costs, we assume that 55% of each kWh sale is earmarked for fixed cost recovery.[8] The other 45% of the lost revenue is assumed to cover variable costs and does not contribute to cost-shifting.

The model assumes that the revenue required for fixed cost recovery does not change; thus non-solar customers receive a rate increase equal to the lost fixed cost recovery amount divided by the total kWh consumed by the non-solar customers.

Utility Model Limitations

This model makes use of several simplifying assumptions. States like California have exceedingly complex rate structures which can alter the impact of distributed PV. Many of those intricacies are not captured within this model. Similarly, solar production was modeled with a statewide average annual generation per installation while in reality, solar production varies greatly from region to region. With time of use rate tariffs, the model assumes that 55% of the per-kWh charge is attributed to fixed costs such as transmission and distribution, regardless of time of day. In reality, the percentage of the energy charge attributed to fixed costs varies with the time of day, and our assumed 55% is a based on an average figure and is not specific to California.

Solar Model

The purpose of the solar rate model is to estimate the amount of money a distributed PV owner saves by buying electricity from her rooftop system instead of the grid. In analyzing the impact of different policy options on distributed PV owners, we assume that the primary driver of solar adoption among residential customers is the financial savings they realize by hosting a solar system on their roof. A distributed PV owner’s “financial savings” has two components. First, in the case of third party-owned systems, they pay less for the electricity generated from their rooftop than they would have for grid electricity. Their savings equals the total quantity of electricity purchased multiplied by the difference between the rate they pay for it (usually through a PPA) and the retail rate charged by the utility. Second, each kWh of electricity they purchase from their rooftop but do not use is sold back to the grid as a price greater than they paid. These two components are summed to calculate the PV owner's financial savings. We model impacts in Arizona and California, as both are states with large solar resources, a well-developed solar industry, and intense political scrutiny around questions of integrating distributed PV into the grid. The model's inputs come from publicly available data where available. Average household electricity consumption and average residential retail electricity rates come from the EIA's average monthly residential electricity consumption, prices, and bills by state database. Assumptions for the average size of a solar system, the average energy exported, and average PPA rates come from NREL and others.

Solar Model Limitations

Given the intensely technical nature of this modeling exercise, the model naturally has its limitations. First, the model uses EIA data for average household consumption and the average retail electricity rate. This may understate consumption, which tends to be higher in households with solar. In addition, the average electricity rate does not reflect time of use pricing, which some utilities and rate classes in California have.

Cost-shifting in the Current State

Our analysis shows that the impact of cost shifting under current levels of distributed PV penetration and at prevailing electricity prices appears to be relatively small – both as a percentage of a utility's revenue requirement, and in terms of the magnitude of rate increases that result. At current levels of distributed PV penetration, the total amount of lost revenue that would otherwise have been used to pay for fixed costs amounts to approximately 1% of the revenue requirement of residential customer classes. Figure 14 below shows shifted costs as a percentage of a utility's revenue requirement at differing distributed PV penetration levels in California.

Figure 14: Shifted Costs as a Percentage of Utility Revenue Requirement in California

Shifted Costs as Distributed PV Penetration Increases	
# Distributed PV Installations	Shifted Costs as Percentage of Revenue Requirement
70,000	1.10%
75,000	1.18%
80,000	1.26%
85,000	1.34%
90,000	1.42%
95,000	1.50%
100,000	1.58%
105,000	1.66%
110,000	1.73%
115,000	1.81%
120,000	1.89%
125,000	1.97%
130,000	2.05%
140,000	2.21%

The relationship between the level of distributed PV penetration and revenue loss is expected to be linear. Shifted costs amounting to 1% of revenue requirement would force a utility to raise its rates approximately 1.6% for non-solar customers in order to continue to recover all fixed costs. It is important to note that 1.6% may be more significant when taken in context of other factors driving rate increases for utilities, such as fuel costs, infrastructure improvements, and investments in increased capacity.

Modeling the effects of fixed fees

The magnitude of cost shifting due to increasing penetration of PV can be expressed on a per-PV owner basis. This number represents the fixed cost that each PV-owner is no longer paying. To mitigate the result cost shift, one solution is to implement an additional fee for PV owners that completely covers their fixed cost obligation, a solution similar to what is being sought in Arizona and California. This solution would separate the PV owner's fixed cost obligations from the value of their solar generation.

The second part of the utility analysis examines how fixed fees could be used to address cost shifting. Under our initial assumptions that produced shifted costs amounting to 1% of the revenue requirement, each distributed PV owner in California would have to pay a fixed fee of just under $71 in order for the utility to continue recovering all fixed costs and eliminate the retail electricity rate increase, with modeled net metering rate of $0.26. California has recently authorized utilities to charge PV owners up to $10 per month to reduce the impact of cost shifting. Adding a $10 fixed fee to our scenario reduces the rate increase to 1.43% from 1.66%. While it is an improvement, it may not materially solve the cost-shifting problem the utility faces. On the other hand, a $70 fixed fee is unlikely to be politically feasible, and significantly changes the incentives for grid-connected and distributed PV rate payers.

Figure 15: Fixed Fee Obligation as Net Metering Rate Varies

`Modeled NM Rate	Annual Fixed Cost Obligation	Monthly Obligation
$0.16	$523	$44
$0.18	$588	$49
$0.20	$653	$54
$0.22	$719	$60
$0.24	$784	$65
$0.26	$849	$71
$0.28	$915	$76
$0.30	$980	$82
$0.29	$947	$79
$0.30	$980	$82

Figure 16: Rate Increase as Fixed Fee Varies

Fixed Fee	Rate Increase
$0.00	1.66%
$5.00	1.55%
$10.00	1.43%
$15.00	1.31%
$20.00	1.19%
$25.00	1.08%
$30.00	0.96%
$35.00	0.84%
$40.00	0.72%
$45.00	0.61%
$50.00	0.49%
$55.00	0.37%
$60.00	0.25%
$65.00	0.14%
$70.00	0.02%

Effects of Fixed Fees for Distributed PV Owners

Now that we have established the level of fixed fee that eliminates cost shifting for a utility with conditions similar to those faced in California, we examine the effect of those fixed fees on solar owners. To do so, we turn to our solar savings model and compute the savings (or loss) associated with a fixed fee of $71 per solar owner per month in California. Under a $71 fixed fee solar owners in California would pay $64 more than they would have had they continued buying electricity from the grid. Given current retail rates, consumption levels, and PPA rates, a $71 fixed fee would eliminate any savings previously enjoyed by solar owners. In fact, this finding fits what solar advocates in both states have described: high fixed fees represent a threat to the solar industry because they have the potential to eliminate the savings they offer new customers.

Based on recent events in Arizona and California, there seems to be a trend toward utilities charging solar owners a fixed fee to help recover their fixed costs. Negotiations in both Arizona and California led to fees in the $5 - $10 range. If fixed fees are here to stay, what level of fixed fee can a utility charge without eliminating the savings that constitute the value proposition of a residential solar PV system? Figures 17 and 18 below show how different levels of net metering reimbursement and fixed fees affect the savings a residential consumer can expect from a rooftop solar system in Arizona or California. Solar advocates maintain that savings of greater than $5/month are important to convince new customers to purchase solar systems,[56] so those savings values of greater than $5/month are shown in black. Blue values denote savings of less than $5/month; losses are shown in red.

Figure 17: Residential Customers Savings from Switching to Distributed PV in Arizona

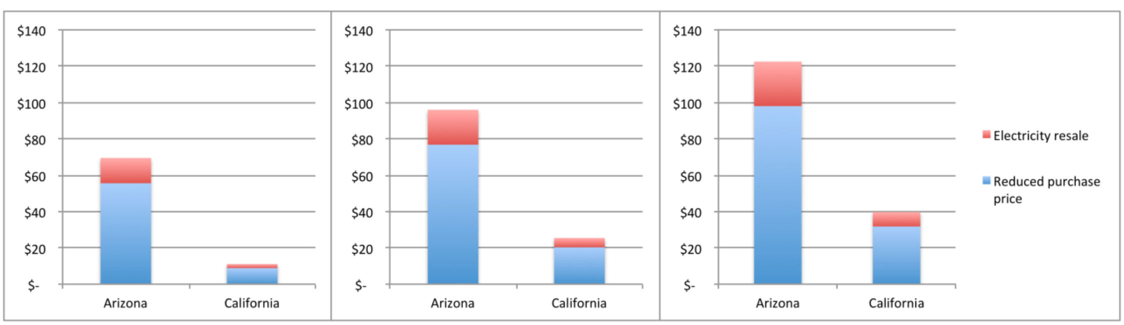
NEM Rate (Retail electricity rate)	Fixed fee										
	$5	$10	$15	$20	$25	$30	$35	$40	$45	$50	$55
$0.10	($15.11)	($20.11)	($25.11)	($30.11)	($35.11)	($40.11)	($45.11)	($50.11)	($55.11)	($60.11)	($65.11)
$0.11	($1.85)	($6.85)	($11.85)	($16.85)	($21.85)	($26.85)	($31.85)	($36.85)	($41.85)	($46.85)	($51.85)
$0.12	$11.41	$6.41	$1.41	($3.59)	($8.59)	($13.59)	($18.59)	($23.59)	($28.59)	($33.59)	($38.59)
$0.13	$24.68	$19.68	$14.68	$9.68	$4.68	($0.32)	($5.32)	($10.32)	($15.32)	($20.32)	($25.32)
$0.14	$37.94	$32.94	$27.94	$22.94	$17.94	$12.94	$7.94	$2.94	($2.06)	($7.06)	($12.06)
$0.15	$51.20	$46.20	$41.20	$36.20	$31.20	$26.20	$21.20	$16.20	$11.20	$6.20	$1.20
$0.16	$64.46	$59.46	$54.46	$49.46	$44.46	$39.46	$34.46	$29.46	$24.46	$19.46	$14.46
$0.17	$77.73	$72.73	$67.73	$62.73	$57.73	$52.73	$47.73	$42.73	$37.73	$32.73	$27.73
$0.18	$90.99	$85.99	$80.99	$75.99	$70.99	$65.99	$60.99	$55.99	$50.99	$45.99	$40.99
$0.19	$104.25	$99.25	$94.25	$89.25	$84.25	$79.25	$74.25	$69.25	$64.25	$59.25	$54.25
$0.20	$117.51	$112.51	$107.51	$102.51	$97.51	$92.51	$87.51	$82.51	$77.51	$72.51	$67.51
$0.21	$130.78	$125.78	$120.78	$115.78	$110.78	$105.78	$100.78	$95.78	$90.78	$85.78	$80.78
$0.22	$144.04	$139.04	$134.04	$129.04	$124.04	$119.04	$114.04	$109.04	$104.04	$99.04	$94.04
$0.23	$157.30	$152.30	$147.30	$142.30	$137.30	$132.30	$127.30	$122.30	$117.30	$112.30	$107.30
$0.24	$170.56	$165.56	$160.56	$155.56	$150.56	$145.56	$140.56	$135.56	$130.56	$125.56	$120.56
$0.25	$183.83	$178.83	$173.83	$168.83	$163.83	$158.83	$153.83	$148.83	$143.83	$138.83	$133.83
$0.26	$197.09	$192.09	$187.09	$182.09	$177.09	$172.09	$167.09	$162.09	$157.09	$152.09	$147.09
$0.27	$210.35	$205.35	$200.35	$195.35	$190.35	$185.35	$180.35	$175.35	$170.35	$165.35	$160.35
$0.28	$223.61	$218.61	$213.61	$208.61	$203.61	$198.61	$193.61	$188.61	$183.61	$178.61	$173.61
$0.29	$236.88	$231.88	$226.88	$221.88	$216.88	$211.88	$206.88	$201.88	$196.88	$191.88	$186.88
$0.30	$250.14	$245.14	$240.14	$235.14	$230.14	$225.14	$220.14	$215.14	$210.14	$205.14	$200.14

Figure 18: Residential Customer Savings from Switching to PV in California

NEM Rate (Retail electricity rate)	Fixed fee $5	$10	$15	$20	$25	$30	$35	$40	$45	$50	$55
$0.10	($36.89)	($41.89)	($46.89)	($51.89)	($56.89)	($61.89)	($66.89)	($71.89)	($76.89)	($81.89)	($86.89)
$0.11	($29.73)	($34.73)	($39.73)	($44.73)	($49.73)	($54.73)	($59.73)	($64.73)	($69.73)	($74.73)	($79.73)
$0.12	($22.57)	($27.57)	($32.57)	($37.57)	($42.57)	($47.57)	($52.57)	($57.57)	($62.57)	($67.57)	($72.57)
$0.13	($15.40)	($20.40)	($25.40)	($30.40)	($35.40)	($40.40)	($45.40)	($50.40)	($55.40)	($60.40)	($65.40)
$0.14	($8.24)	($13.24)	($18.24)	($23.24)	($28.24)	($33.24)	($38.24)	($43.24)	($48.24)	($53.24)	($58.24)
$0.15	($1.08)	($6.08)	($11.08)	($16.08)	($21.08)	($26.08)	($31.08)	($36.08)	($41.08)	($46.08)	($51.08)
$0.16	$6.08	$1.08	($3.92)	($8.92)	($13.92)	($18.92)	($23.92)	($28.92)	($33.92)	($38.92)	($43.92)
$0.17	$13.25	$8.25	$3.25	($1.75)	($6.75)	($11.75)	($16.75)	($21.75)	($26.75)	($31.75)	($36.75)
$0.18	$20.41	$15.41	$10.41	$5.41	$0.41	($4.59)	($9.59)	($14.59)	($19.59)	($24.59)	($29.59)
$0.19	$27.57	$22.57	$17.57	$12.57	$7.57	$2.57	($2.43)	($7.43)	($12.43)	($17.43)	($22.43)
$0.20	$34.73	$29.73	$24.73	$19.73	$14.73	$9.73	$4.73	($0.27)	($5.27)	($10.27)	($15.27)
$0.21	$41.90	$36.90	$31.90	$26.90	$21.90	$16.90	$11.90	$6.90	$1.90	($3.10)	($8.10)
$0.22	$49.06	$44.06	$39.06	$34.06	$29.06	$24.06	$19.06	$14.06	$9.06	$4.06	($0.94)
$0.23	$56.22	$51.22	$46.22	$41.22	$36.22	$31.22	$26.22	$21.22	$16.22	$11.22	$6.22
$0.24	$63.38	$58.38	$53.38	$48.38	$43.38	$38.38	$33.38	$28.38	$23.38	$18.38	$13.38
$0.25	$70.55	$65.55	$60.55	$55.55	$50.55	$45.55	$40.55	$35.55	$30.55	$25.55	$20.55
$0.26	$77.71	$72.71	$67.71	$62.71	$57.71	$52.71	$47.71	$42.71	$37.71	$32.71	$27.71
$0.27	$84.87	$79.87	$74.87	$69.87	$64.87	$59.87	$54.87	$49.87	$44.87	$39.87	$34.87
$0.28	$92.03	$87.03	$82.03	$77.03	$72.03	$67.03	$62.03	$57.03	$52.03	$47.03	$42.03
$0.29	$99.20	$94.20	$89.20	$84.20	$79.20	$74.20	$69.20	$64.20	$59.20	$54.20	$49.20
$0.30	$106.36	$101.36	$96.36	$91.36	$86.36	$81.36	$76.36	$71.36	$66.36	$61.36	$56.36

The figures show that conditions in Arizona make residential solar economics more resilient to increased fixed fees than California. Though savings in both states under current regimes average about $7, Arizona's higher energy consumption (1061 kWh/month) and lower PPA rates ($.1076) mean that savings in Arizona are higher than those in California at higher net metering and retail rates. Figure 19 below shows how the two components of savings change at higher net metering and retail rate levels.

Figure 19: Components of Savings to Distributed PV Owners under Varying Retail Rates



The figures also reveal the net metering rate that would be necessary to maintain at least some savings for residential solar owners. In Arizona, net metering rates over $.16 would maintain levels of savings greater than $5 with fixed fees up to $55. In California, the net metering rate must be much higher, upwards of $.23. Though net metering rates are not currently at such levels in each state, it is likely that they will be soon given regular retail rate increases. Assuming net metering continues to be linked to retail electricity rates, there will come a point, likely in the near future, where fixed fees will be much easier for residential solar owners to bear. Under the current scenario, it is in the solar industry's best interest to find a path to legislation or PUC rulings that establish long-term net metering set at the retail rate.

Analysis of Value of Solar Tariff

The VOS tariff is another potential solution to the problems faced by utilities and distributed PV owners in integrating distributed PV into the grid. As described earlier in this paper, the methodology for existing VOS tariff programs dictates a "buy-all, sell-all" arrangement where a solar owner sells all of the electricity they generate to the utility at a pre-defined "value of solar" rate. The customer continues to buy electricity from the grid as usual, but is able to offset their cost of grid electricity with solar electricity sold to the utility at the VOS rate. In this arrangement, solar electricity is purchased at a rate that captures the value it provides to the utility, and consumers continue to purchase electricity from the grid, eliminating the issue of cost shifting and lost revenue for utilities. It is important to note that VOS tariffs are only being used in states where state law does not allow third parties to own solar installations, which means that solar companies there cannot offer a PPA.

From the perspective a rooftop solar owner, which is more attractive, VOS tariffs or net metering? Table 3 shows yearly savings under net metering and VOS regimes using assumptions for Arizona. The table extends to 10 years – the amount of time Minnesota's VOS tariff is fixed – and increases the retail electricity rate 1% each year to mimic steadily increasing retail electricity prices. In year 0, the benefit of a VOS tariff is more than 300% larger than the benefit of net metering. If we were a solar PV owner choosing between the two regimes in year 1, we would likely choose a VOS tariff. However, over time, rising retail rates erode the value created by VOS tariffs for solar owners. Though they still make money selling their electricity to the grid, by year 6 that benefit is no longer greater than the cost of buying electricity from the grid. The net positive financial benefit that drives solar uptake by consumers is lost. In fact the total net benefit to a distributed PV owner over a 10-year period is negative. Conversely, under net metering, the financial benefit continues to rise as long as the price at which the consumer buys her solar electricity is less than the retail utility rate, which is a safe assumption given the steadily falling costs of solar and steadily-rising retail rates. Over the same 10-year period, the value of savings to a distributed PV owner on a net metering tariff would be more than $470. For a VOS tariff to generate equivalent value, it would have to be adjusted every year and maintain a nearly 30% premium over the retail rate (see appendix for calculation). While VOS tariffs address problems for both utilities and distributed PV owners, it ignores other problems, and generates benefits that may only be relevant in the near term.

Figure 20: Yearly Average Savings Under Net Metering and VOS Regimes

	YEAR 0	1	2	3	4	5	6	7	8	9	10
Retail rate	**$ 0.1129**	**$ 0.1140**	**$ 0.1163**	**$ 0.1198**	**$ 0.1247**	**$ 0.1311**	**$ 0.1391**	**$ 0.1492**	**$ 0.1615**	**$ 0.1767**	**$ 0.1952**
NEM	$7.00	$8.49	$11.53	$16.21	$22.66	$31.10	$41.79	$55.10	$71.50	$91.57	$116.08
VOST	$23.34	$22.14	$19.71	$15.97	$10.81	$4.06	-$4.50	-$15.14	-$28.26	-$44.31	-$63.93

* Assumes 1% per year retail rate price escalator

10-year cumulative savings

	Sum	NPV
NEM	$ 473.04	$ 369.62
VOST	$ (60.10)	$ (27.93)

Discount rate = 3%

Recommendations

The following recommendations are informed by our literature review as well as the above analysis. The overarching goal is to provide state regulators with guiding principles for adjusting electricity tariffs in order to better accommodate distributed PV. Specifically, our recommendations address the two pricing inefficiencies identified in this paper through changes to the prevailing rate structure.

1. Separate pricing of electric service components.

This paper has identified two pricing inefficiencies that underlie the challenge that distributed PV poses for utilities: volumetric pricing for fixed cost recovery, and mis-pricing of distributed PV generation. The two pricing inefficiencies combine to fuel an intense debate about how distributed PV should be treated. Currently, utilities recover fixed costs such as a transmission and distribution investments primarily through per-kWh fees. In effect, utilities are allocating fixed costs to its customers based on each customer's consumption of electricity. While it is reasonable to expect that differences in consumption correspond to different uses of fixed assets, it is not reasonable for a customer's obligation to pay for fixed costs to be tied entirely to consumption. Each household is responsible for a portion of the utility's fixed costs, but it should be priced and charged separately from its obligation to pay for variable costs.

The pricing inefficiency is made evident with customer-sited generation such as distributed PV - with a net metering tariff, it is possible for a customer to purchase zero kWh from the utility, and contribute nothing to fixed costs. This phenomenon has incented the development of new rate design proposals and fee allocations so that the compensation distributed PV owners receive for their electricity takes into account fixed, non-bypassable system fees. Current rate retail rate structures and net metering attempt to embed four separate components into the price per kWh: cost of being able to buy grid electricity (fixed costs), variable costs of energy delivered to the customer, cost of being able to sell electricity to the grid, and value of solar electricity to the grid. We recommend that each component be priced separately through its own pricing mechanism, though recommendations for pricing the variable costs of energy delivered to the customer and the benefit of being able to sell electricity to the grid are beyond the scope of this paper. Our recommendations focus on pricing fixed costs and the value of solar electricity to the grid.

2. Create a pricing mechanism that helps utilities recover their fixed costs more effectively from distributed generators.

State regulators should help utilities create a pricing mechanism that charges residential customers a separate fee to aid in the recovery of fixed costs. This approach enables utilities to price fixed costs in a manner more similar to how they are incurred and reduces the possibility for cost-shifting and cross-subsidization. Our analysis shows that full fixed cost recovery through a fixed fee could result in a very high fixed charge, but it is not certain that the goal of a fixed fee should be full fixed cost recovery. PUCs and other regulators should be explicit about whether a utility has that right, and how much of that recovery should be accomplished through a fixed charge or through volumetric charges. We are in favor of residential customers paying more of their bill through fixed fees; this better matches the manner in which the utility's costs are incurred and limits the risk of costs shifting.

3. Compensate distributed PV owners for the value that solar generation provides the grid.

We recommend that regulators establish methodologies to value the contribution of solar generation to the grid and compensate distributed PV owners according to the value they provide to the grid. We suggest using solar valuation methodologies similar to the VOS tariff implemented by Austin and Minnesota as a starting point to determine the price per kWh paid to distributed PV owners. Regardless of the valuation methodology, the value of each kWh generated by distributed PV should be independent of the owner's fixed cost obligation, which we believe should be priced separately.

While we recommend that regulators use the VOS tariff cases in Austin and Minnesota as the basis of a methodology for pricing solar electricity, we suggest that they consider a different compensation structure than was implemented in those cases. Current VOS tariff regimes require distributed PV owners to export all the electricity they generate to the grid and pay them a price based on the value of that solar generation. However, ratepayers still purchase all their electricity from the grid. We recommend that VOS compensation be structured more like net metering, which exports electricity (and triggers a transaction) only if a PV system generates more electricity than a household uses at any given time.

This scenario has two important advantages to current VOS compensation structure. First, the PV owner will still receive retail value if he is reducing his consumption. This is akin to enacting energy efficiency measures - a homeowner does not pay the utility when he decides to use less electricity. It is only when the homeowner sends electricity back to the grid that he should receive a different value. Second, it allows the homeowner to achieve a level of energy independence, and is most reflective of the physical reality of installing solar panels on the roof. The value assigned to energy exported to the grid should be reevaluated on a frequent basis. Energy markets are sensitive to changes in volatile commodity markets, and it follows that the value of electricity produced by a distributed PV system would change as the overall environment is changing. One possibility is to revalue the rate whenever a utility wishes to change its retail rate of electricity.

Conclusion

This report has introduced and explained the challenge of integrating distributed PV into the current utility structure. Due to the nature of prevailing rate tariffs, utilities are exposed to the possibility of losing contributions toward fixed cost recovery from distributed PV owners. In recent years, the cost of solar installations has fallen dramatically, and financial innovations such as solar PPAs have driven increasing rates of adoption. Utilities in states with high levels of distributed PV penetration, such as Arizona and California have claimed that distributed PV has forced fixed costs from PV owners to non-PV owners and have urged regulators for changes to existing net metering programs in order to decrease amount of lost fixed cost recovery. Similarly, solar advocates have sought higher payments for kWh that distributed PV systems send back into the grid. We take the position that utilities and solar advocates are asking regulators to solve for two different pricing inefficiencies, both of which need to be addressed.

The first inefficiency is the manner in which fixed costs are recovered by utilities, and the second is the pricing and valuation of kWh produced by distributed PV. The foundation of our recommendations is that electricity service components must be priced separately; each customer should be aware of his or her fixed cost obligations. Secondly, we recommend a shift away from pushing the majority of a residential customer’s bill onto per kWh charges, and separate the pricing of having access to the grid from the use of electricity, similar to pricing structures used in the telecommunications industry. Lastly, the pricing of kWh sold onto the grid from distributed PV systems should be the result of a comprehensive evaluation of the value provided to the grid. Implementing the above recommendations will require state regulators to change long-established rate tariffs and perform new analyses on the value of distributed PV, but it is clear that existing structures are unable to adapt to growing levels of distributed PV and policy changes are necessary.

Appendix

A. Utility Model Formulas

A. Average cost per kWh needed to reach revenue requirement:
$Revenue\ Requirement\ \div All\ Planned\ kWh\ Sales$

B. Lost revenue from distributed PV
$\#\ of\ PV\ Installations\ \times Average\ Annual\ Output\ \times Average\ NEM\ Value$

C. Additional fixed fee charge (monthly):
$\#\ PV\ Installations\ \times Fixed\ Fee$

D. Lost fixed cost recovery:
$(0.55\ \times\ \boldsymbol{B}) - \boldsymbol{D}$

E. Lost fixed cost recovery as percentages of revenue requirement:
$\boldsymbol{D} \div Revenue\ Requirement\ \times 100$

F. Average rate increase necessary per kWh:
$\boldsymbol{B}\ \div (Non\ PV\ Customers \times Average\ kWh\ Consumed\ per\ Customers)$

G. Rate increase (%):
$\boldsymbol{E}\ \div \boldsymbol{A}$

B. Examples of States with High Distributed PV Penetration

Arizona

Utility landscape

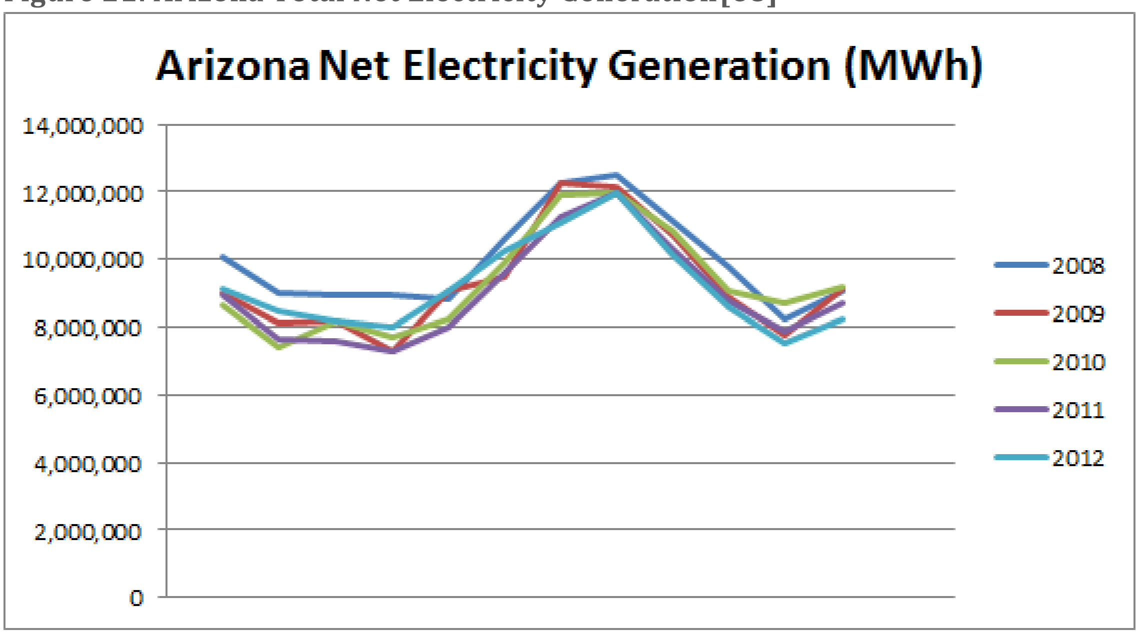
Arizona has two major utilities, Arizona Public Service (APS) and Salt River Project. Arizona Public Service is an investor-owned utility accounting for 38% of retail sales in Arizona, while Salt River Project (36%) is owned by the state of Arizona. Arizona's electric utilities are regulated by the Arizona Corporation Commission, and are not part of a power pool.

Arizona's utilities are vertically integrated.[67] The state had initiated the restructuring of its market in the late 1990s but suspended the restructuring in 2010 in the wake of the California energy crisis. The public utility commission of Arizona ACC is in the process of evaluating a resumption of restructuring, which seems unlikely.

Load profile

Arizona's load peaks in summer at about 19 Gigawatt; its winter peak reaches 70% of the summer peak and the ratio of yearly average load to peak load is 44%, as shown in Figure 21 below.

Figure 21: Arizona Total Net Electricity Generation[68]



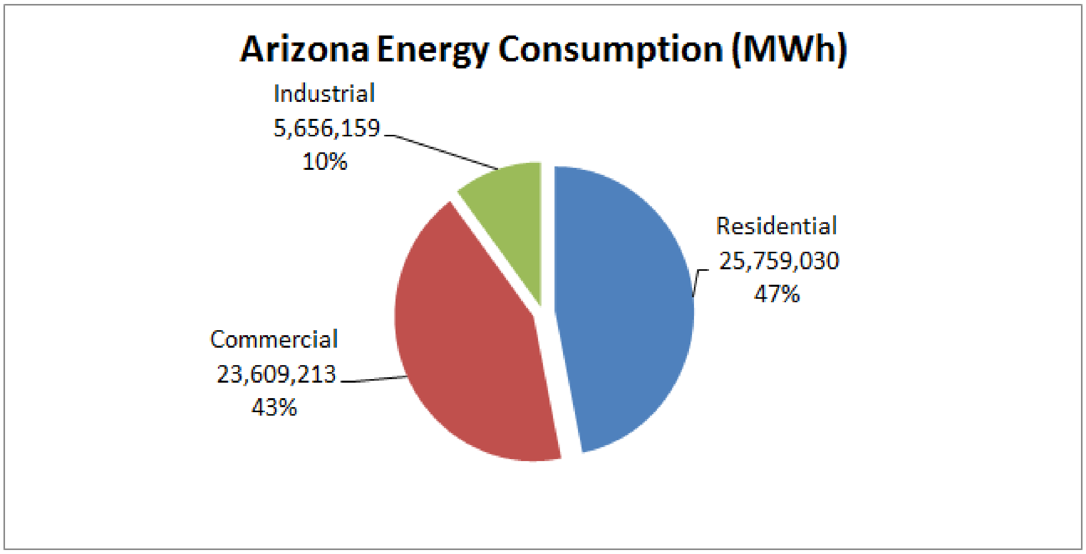
Arizona's electricity prices are close to the median in the United States. The weighted average tariff of the two main utilities in Arizona is as follows:

- Residential: \$0.108 per kWh
- Commercial: \$0.083 per kWh

- Industrial: \$0.015 per kWh

Among APS customers, approximately 6% of residential ratepayers benefit from a low income tariff of about \$0.096 per kWh, compared to the average residential APS tariff of about \$0.123 per kWh.

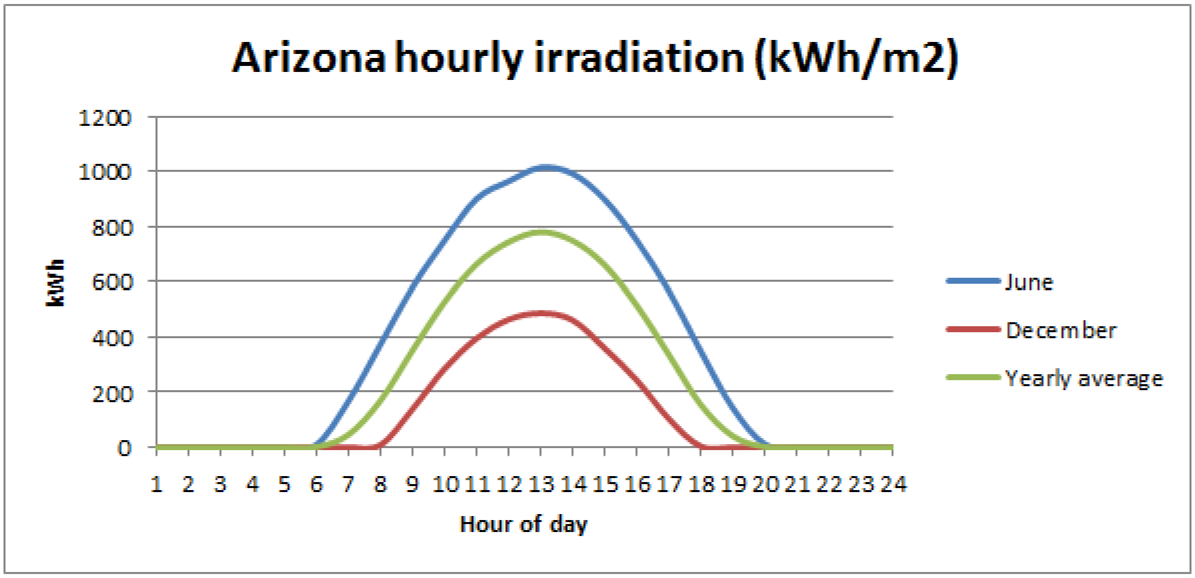
Figure 22: Arizona's Electricity Consumption by End-Use Sector[69]



Distributed PV penetration

Arizona's total distributed PV capacity, measured in direct current, reached approximately 260 MW in early 2013. This corresponds to about 18% of Arizona's total solar energy capacity, which is predominantly utility-scale. Residential PV systems account for about 110 MW. Distributed solar energy has been growing by over 100 MWdc each year since 2011. Arizona has a consistently high insolation across the entire state, its annual average is perhaps the highest of all states with about 7.6 kWh/m2 per day.[70]

Figure 23: Arizona Hourly Irradiation[39]



Policies

Arizona's net metering policies recently became the focus of an intense debate between net metering proponents and electric utilities. The Arizona Corporation Commission had established net metering rules in 2009, which compensate customers generating energy from a wide variety of renewable technologies. The rules don't limit the size of the system; the only constraint is that its capacity can't exceed 125% of the customer's total connected load. Monthly net excess generation by the customer is deducted from the customer's next bill at the utility's retail rate. Excess generation at the end of the year is credited at the utility's avoided cost. Customers taking advantage of time-of-use tariffs are compensated at the tariff in force when the electricity is generated, meaning most solar energy is compensated at on-peak rates. There is no cap on net metered systems in the grid of a utility; utilities wishing to set such a cap must demonstrate the need for it.

In November 2013, the debate finally resulted in a ruling by the Arizona Corporation Commission in which the regulator acknowledged a cost-shifting impact from net metering from distributed PV-owning customers to others. The commission decided to continue Arizona's net metering policy, but also to charge net-metering customers a monthly connection fee of $0.70 per kW of system capacity.

Arizona has a renewable energy standard requiring investor-owned utilities and electric cooperatives to obtain renewable energy credits for 15% of their load by 2025. The standard further requires that 30% of the renewable energy credits come from distributed energy sources, of which half is to be derived from residential distributed PV.

The Arizona Corporation Commission started a rulemaking process in 2007 to develop interconnection standards for the entire state. This process is still ongoing. In the meantime, utilities are recommended to use the commission's draft rules as a guide, which apply to systems up to 10 megawatts.

California

Utility Landscape

The retail market is dominated by two major investor-owned utilities: Pacific Gas & Electric and Southern California Edison, which account for 60% of California's end-user energy sales. Each sells close to 90,000 GWh annually.[71]

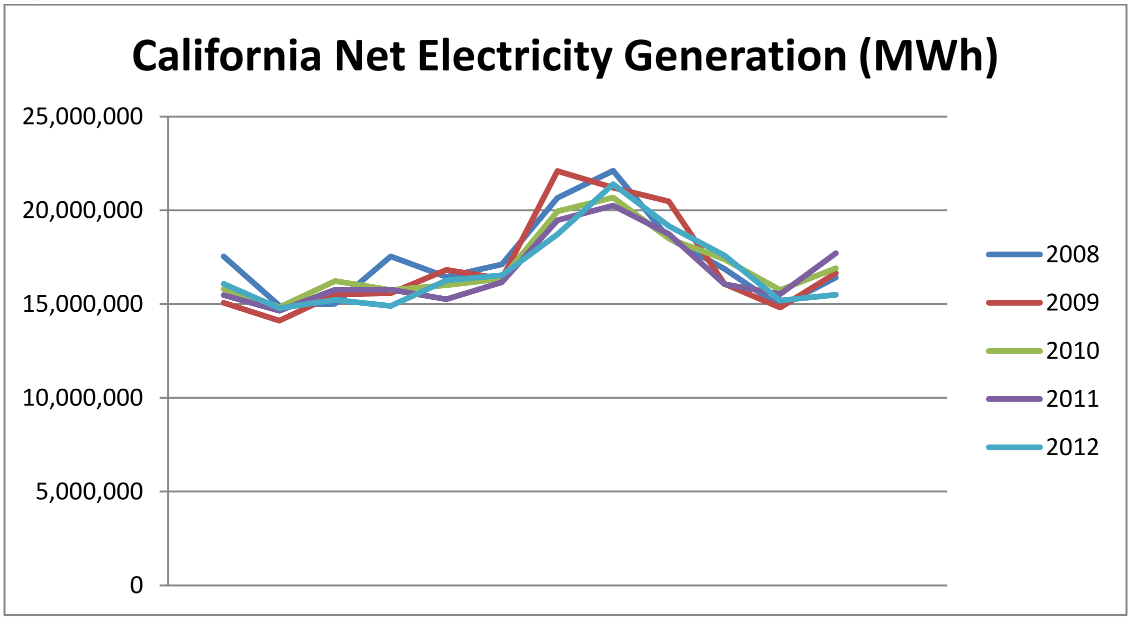
California has a partially deregulated electricity market. Residential customers can only buy their electricity from utilities; however, for commercial and industrial consumers, there is some retail choice (called "Direct Access") for which customers can buy from energy service providers rather than utilities. However, the retail choice is capped at about 10% of load, which corresponds to 850,000 MWh per year. This cap is usually met within minutes of the offering every year.[72]

California has its own ISO, CAISO. CAISO was created in 1998 when California restructured its electricity market. It serves most of California and a small part of Nevada. California imports 30% of its electricity, which flows from the Pacific Northwest and the Southwest to CAISO's high voltage grid.

Load Profile

As stated earlier, the majority of California's population of 38 million is served by Pacific Gas & Electric (PG&E) and Southern California Edison (SCE). Each of the two utilities serves approximately 5.1 million households and business customers. California's load is distributed as follows: residential load 37%, commercial load 47%, and industrial load 16%.[71] As would be expected, California is a summer peak state; its winter peak reaches 74% of its summer peak. The average annual load is 40% of summer peak load.

Figure 24: California Total Net Electricity Generation[68]



Distributed PV Penetration

California has an installed distributed PV capacity of 3,500 MW, which corresponds to roughly 5% of California's total summer capacity. SPV is growing very fast; a third of total PV capacity was installed in 2012 alone. Estimating based only on data for capacity installed between 2011 and the first quarter of 2013, residential capacity accounts for approximately 40% of total distributed solar capacity.[27]

Policies

California's utilities are required to allow net metering up to certain limits. There is a size limit of 1 MW (5 MW for certain public buildings) per system and an aggregate cap of 5% of aggregate customer peak demand. Excess generation is credited to next month's bill at retail rate. The current retail rate as of July 2013 is 16.73 cents. After 12 months, customers can choose either rolling over the credit or getting compensated with spot-market prices.[34]

AB 327, as amended, sets clear figures for when each utility will reach the aggregate cap. The cap will be reached either by December 31, 2016, or at the following capacities, whichever comes first: 607 megawatts for SDG&E; 2,240 megawatts for SCE; and 2,409 megawatts for PG&E.[34]

All investor-owned utilities and publicly-owned utilities with 75,000 or more customers must make a standard feed-in tariff available to their customers. The California feed-in tariff allows eligible customer-generators to enter into 10-, 15- or 20-year standard contracts with their utilities with renewable energy systems up to 3 MW. The price paid will be based on the Renewable Market Adjusting Tariff (Re-MAT). The Re-MAT starting price is based on the weighted average of the three investor-owned utilities highest executed contract resulting from the Renewable Auction Mechanism auction held in November 2011. Based on the results of that auction the CPUC anticipates the starting price will be $89.23 per megawatt-hour.[73]

California has a Renewable Portfolio Standard (RPS) requiring 33% renewable energy by 2020. There is no solar carve-out or REC multiplier and no distributed PV requirement. The terms of the RPS allow customers who feed electricity into the grid to retain the ownership of the generated renewable energy credits even if they sell the energy to the utility, except for customers who are net excess producers of energy at the end of the year, in which case the utility obtains the renewable energy credits.[34]

Massachusetts

Utility Landscape

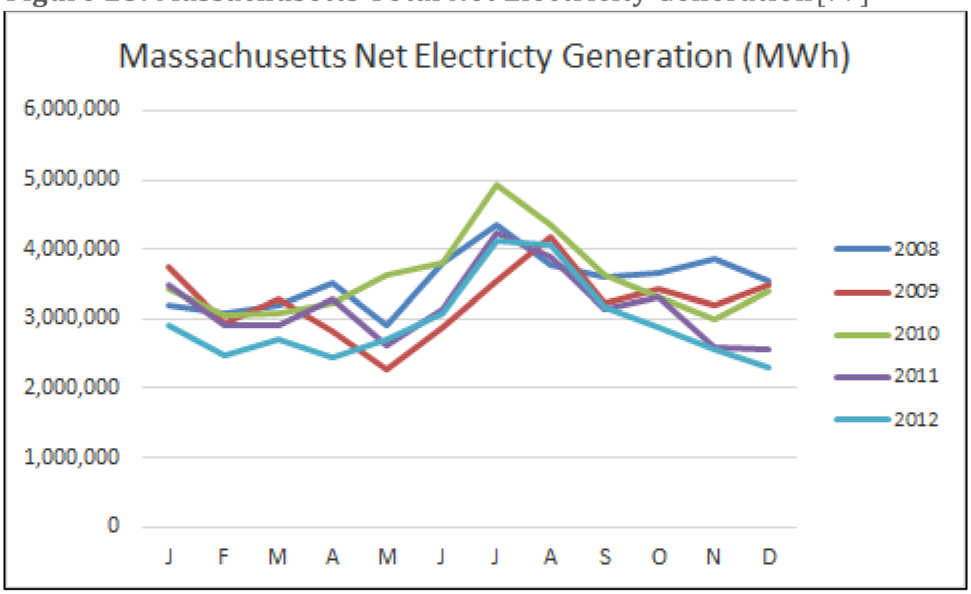
Massachusetts has a restructured wholesale electricity market that is part of the New England ISO, along with Connecticut, Maine, New Hampshire, Rhode Island, and Vermont. Via retail market restructuring, customers in Massachusetts are allowed retail choice, and currently about 18% of customers have switched from their incumbent provider to a competitive provider; otherwise most customers retain default services. Massachusetts has the seventh highest average electricity rates in the U.S.[74-76]

Of the seven major distribution companies in the Massachusetts retail electricity market, there are three utilities that regularly supply over 100 million MWh per month: Massachusetts Electric Co., NSTAR Electric Co., and Western Massachusetts Electric Co. Massachusetts Electric is the largest with over 7.7 million MWh sold and $570 million in electricity revenues in 2012, and the company is owned by the multinational energy corporation, National Grid PLC.[75]

Load Profile

Massachusetts has a summer peak for electricity generation, as shown in Figure 25.

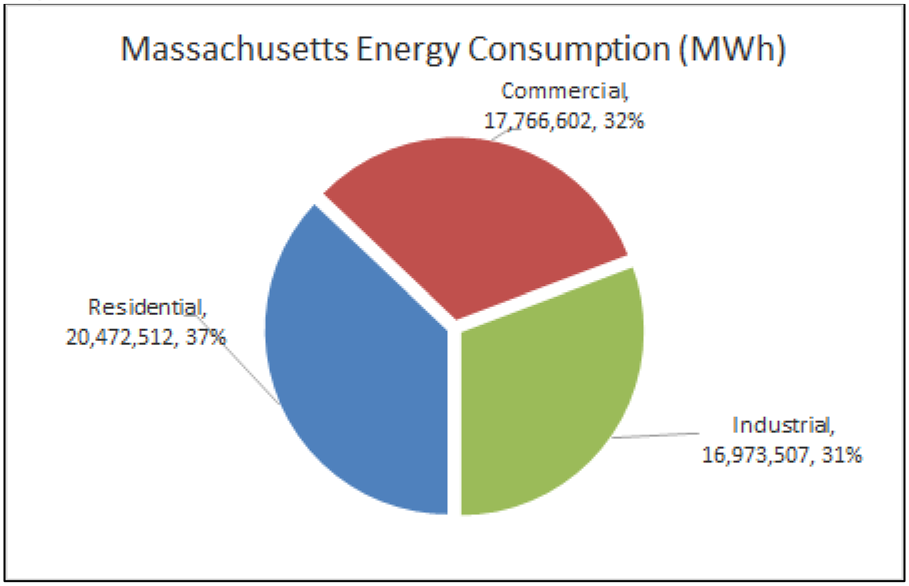
Figure 25: Massachusetts Total Net Electricity Generation[77]



The average retail rates by customer class are the following in Massachusetts (EIA 2012 retail sales and revenue data):

- Residential - 20,123,774 MWh, 37% of load, $0.149 per kWh
- Commercial - 17,299,682 MWh, 32% of load, $0.140 per kWh
- Industrial - 16,766,212 Mwh, 31% of load, $0.129 per kWh

Figure 26: Massachusetts Electricity Generation by End-Use Sector[69]



Distributed PV Penetration

Because of policies favorable to solar, such as net metering, a solar carve-out, and clear interconnection rules, solar installations in Massachusetts have grown rapidly. From less than 50 MW in 2010, the total installed solar capacity as of October 1, 2013 is 327 MW.[78] This amount includes utility scale projects, so it is not entirely distributed.

Policies

Massachusetts allows net metering for certain generators, defining Class I resources as any type of generator up to 60 kW, and biomass, solar, wind, and anaerobic digestion generators up to 1 MW as Class II, and 1 to 2 MW as Class III.[79] Investor-owned utilities are obligated to offer net metering for customers with these generators, while municipal utilities are not. "Massachusetts also allows 'neighborhood net metering' for neighborhood-based Class I, II or III facilities... In aggregate, these 'non-governmental facilities' may not exceed 3% of the distribution company's peak load"[34], while public facilities also have a separate net metering cap of 3%.

As an example, the utility Massachusetts Electric Co. has a historical peak load of 5,131 MW. Therefore, each 3% limit is equal to 153.93MW.[80] The aggregate capacities of net metered projects that fall under these caps, as of October 1, 2013, are as follows: the private cap equals 84.95 MW and the public cap equals 32.64 MW.[80]

The RPS goal for all renewables is 15% by 2020 and an additional 1% per year thereafter. The solar carve-out was 400 MW by 2017, and has recently been updated to 1600 MW of installed capacity by 2020 under the "SREC-II" program.[78] There is no specified distributed PV requirement; however, to achieve the 1600 MW solar carve-out, systems must be no more than 6 MW and use a majority of generated energy for on-site load. These may be owned by electricity customers, utilities, or IPPs.

An interesting policy for solar in Massachusetts is the SREC (Solar Renewable Energy Credit) auction. SRECs are counted towards satisfying the RPS solar carve-out. Recsolar.com points out, "SREC prices still remain relatively high due partly to Massachusetts' Solar Credit Clearinghouse Auction, which sets a de facto floor price of $285.00 for otherwise-unsold SRECs. This is a largely untested policy mechanism, which is why SRECs are currently trading 'through the floor' at prices less than $285.00." As of October 2013, Massachusetts SREC prices were $241.05.[81]

Massachusetts has been reevaluating its interconnection standards for distributed generation, including renewables and CHP, and has issued process updates as recently as March 2013.[34] There are three interconnection categories mainly distinguished by system size: 1) Simplified interconnection process applies to most systems up to 15 kW; 2) Expedited process for facilities on radial EPS that pass certain pre-screenings; 3) Standard process for all other facilities. A more extensive impact study may be required for systems larger than 1 MW, especially if larger than 5 MW.[82]

New Jersey

Utility Landscape

New Jersey is a restructured market with competition at the generation and retail level. The major utilities are all investor-owned: Jersey Central Power and Light, PSE&G, and Atlantic City Electric. In 1999, a state law separated the supply charges and delivery charges for electricity and natural gas. That allowed new companies to sell to customers using existing infrastructure. The result is that businesses and residential customers can buy energy from a list of 70 alternative suppliers without disrupting their service from traditional suppliers like JCP&L and PSE&G, which will still provide service and maintenance during outages. New Jersey averaged the sixth highest electricity prices in the nation in 2011.

New Jersey's electric utilities are regulated by The Division of Energy which part of the Board of Public Utilities. The Division of Electricity oversees the public interest by balancing the needs of customers and utility service providers in the following areas of responsibility: rates, service, infrastructure, issuing authorizations to operate, establishing rates & service standards, and enforcement & compliance activities.[82]

Load Profile

New Jersey electric utilities participate in the PJM Interconnection LLC (PJM) whose members also include Pennsylvania and Maryland. PJM is a Regional Transmission

Organization (RTO) part of the Eastern Interconnection. Figure 27 shows the net electric power generation for the last five years. New Jersey's load profile peaks in summer months due to cooling. The average load is 59% of its summer peak load.

Figure 27: New Jersey's Total Net Electricity Generation[83]

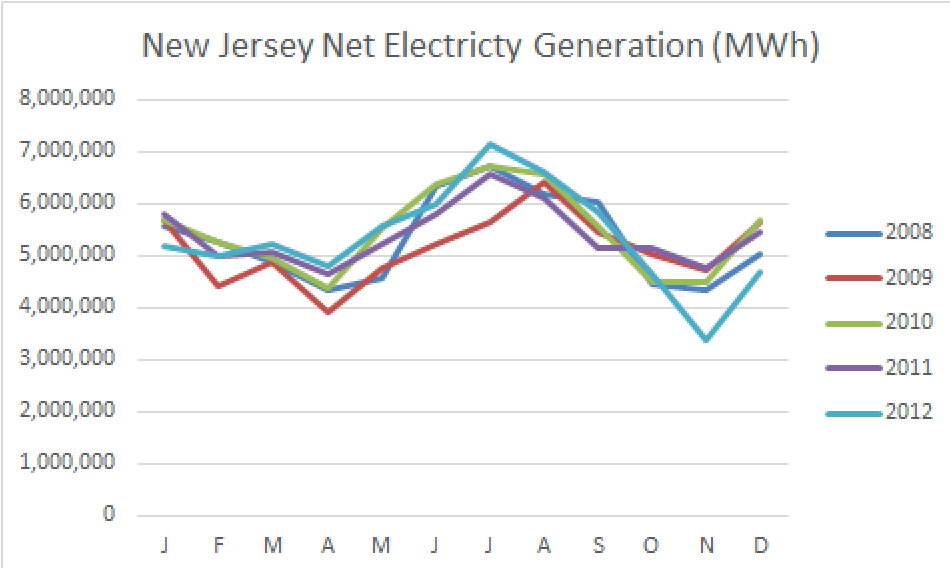
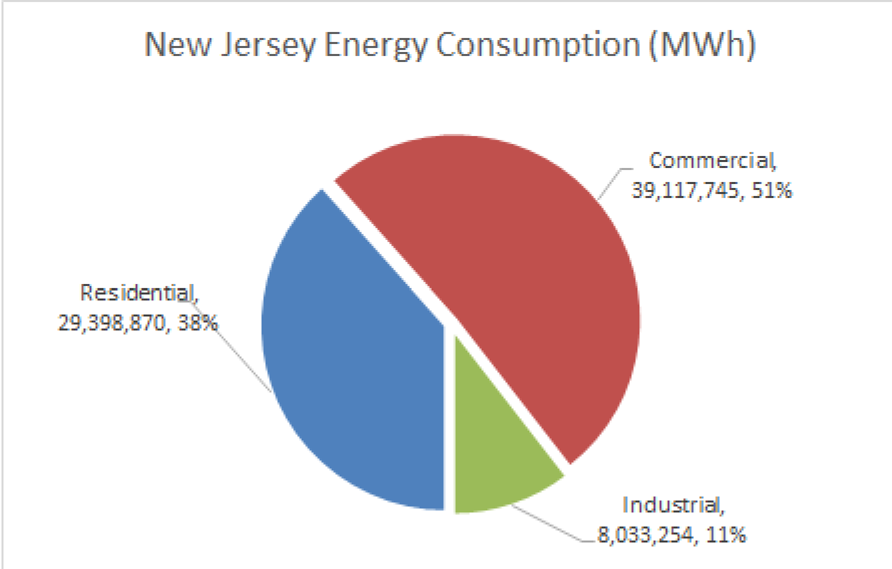


Figure 28 shows New Jersey's 2011 electricity consumption by end-use sector. Average site energy consumption (127 million Btu per year) in New Jersey homes and average household energy expenditures ($3,065 per year) are among the highest in the country.[84]

Figure 28: New Jersey's Electricity Generation by End-Use Sector[76]

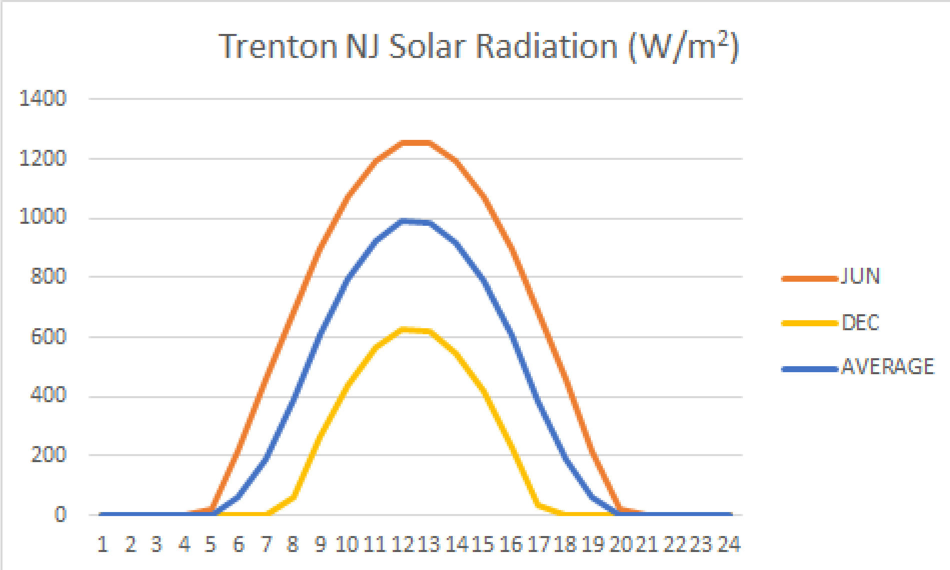


Distributed PV Penetration

New Jersey is one of the fastest growing solar markets in the country, second only to California in overall installations. This growth is driven mainly by New Jersey's renewable portfolio standard which requires 22.5% of its electricity be generated from renewable energy sources by 2021. The 1,119 MW of solar energy currently installed in New Jersey ranks the state 3rd in the country in installed solar capacity.[85] 577 MW of that was installed by net metering customers.[86] In 2012, New Jersey received investments of $1.3 billion to install solar on homes and businesses.[85]

The average insolation for New Jersey is 4.5-5.0 kWh/m^2 per day, which is middle of the pack out in the U.S. Figure 29 shows monthly average solar radiation of Trenton, NJ. The monthly averages vary between the extremes of June and December. Comparing Figure 27 and Figure 29, we see that energy demand peaks in summer but the lowest months are spring and fall. Timing of solar insolation peak generally corresponds with daily and seasonal peak loads:

Figure 29: Monthly Average Solar Radiation of Trenton, NJ[87]



Policies

In April 2006, the New Jersey Board of Public Utilities approved regulations that expanded the State's renewable portfolio standard, requiring utilities to generate 22.5 percent of their electricity from renewable sources by 2021, with solar sources generating at least 2 percent of this standard. The standard does not specifically call out distributed energy or storage requirements.[34]

New Jersey's net-metering rules apply to all residential, commercial and industrial customers of the state's investor-owned utilities and energy suppliers (and certain competitive municipal utilities and electric cooperatives). As of 2012 New Jersey had over 15,000 net meters installed.[86] While no specific system size cap exists, system size remains limited to that needed to meet annual on-site electric demand. There is no firm aggregate limit on net metering, although the BPU is permitted to allow utilities to cease offering net metering if statewide enrolled capacity exceeds 2.5% of peak electric demand. Customer-generator is compensated at the full retail rate for all NEG.[34]

Solar Renewable Energy Certificates (SRECs) represent the renewable attributes of solar generation, bundled in minimum denominations of one megawatt-hour (MWh) of production. New Jersey's SREC program provides a means for SRECs to be created and verified, and allows electric suppliers to buy and retire these certificates in order to meet their solar RPS requirements. All electric suppliers must use the SREC program to demonstrate compliance with the RPS. Customers retain ownership of renewable energy credits but are able to sell them on New Jersey's online marketplace. Average prices ranged from \$225 to \$390 per MWh during 2012 with significant variations for individual trades.[34, 88]

The interconnection rules depend on the size of the system. For systems between 10 kW and 2 MW, owners pay a fee of $50 and $1/kW capacity. Smaller systems pay no fees.[34]

New York

Utility Landscape

New York is a traditionally regulated electricity market. Six large investor-owned utilities, one large municipal utility, and several smaller utilities serve the New York State's approximately four million utility customers. Consolidated Edison (ConEd), the state's largest investor-owned utility, provides gas and electricity to 2.6 million customers primarily in-and-around New York City. New York State's second largest electricity retailer, Long Island Power Authority (LIPA), was effectively privatized when the state passed control of the utility to Public Service Electric & Gas Company (PSE&G) in mid-2013. The publicly owned New York Power Authority (NYPA) is the state's fourth largest electricity retailer, and is the largest state-owned power organization in the U.S.[89]

The New York Independent System Operator (NYISO) manages the state's power grid and wholesale electric markets. The New York Public Service Commission (PSC) regulates utilities across the state. The PSC also oversees the state's telecommunications industry. Overall, the PSC's mission is "to ensure safe, secure, and reliable access to electric, gas, steam, telecommunications, and water services for New York State's residential and business consumers, at just and reasonable rates."[90]

Figure 30 compares the annual fluctuations in New York State's net electric power generation. New York State's load profile peaks in summer months due to cooling. In 2012, the state's average load of 11.4 million MWh was 79% of peak summer load (July) of 14.4 million MWh. For 2014, NYISO forecasted peak summer demand across New York of 33,279 MW.[91] Compared to 38,936 MW of total system generation capacity, New York has a 17% reserve margin of capacity-to-peak demand.

Figure 30: New York State's Total Net Electricity Generation[83]

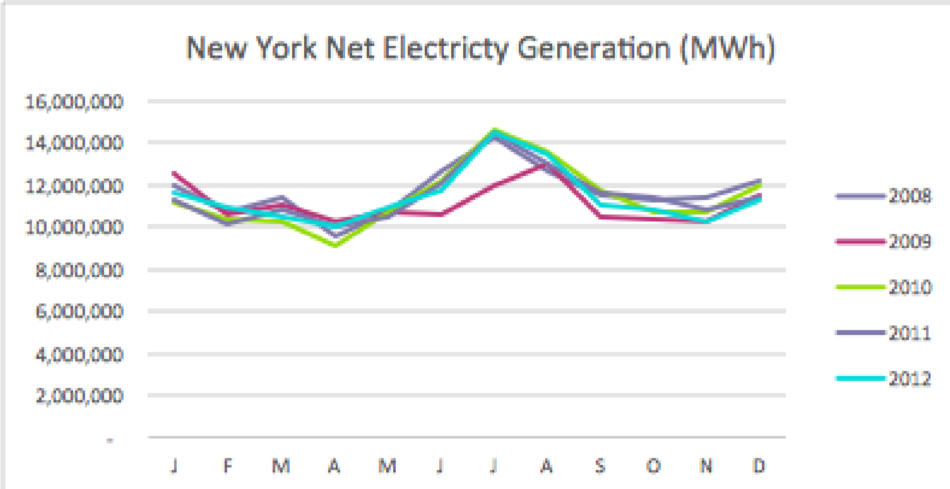
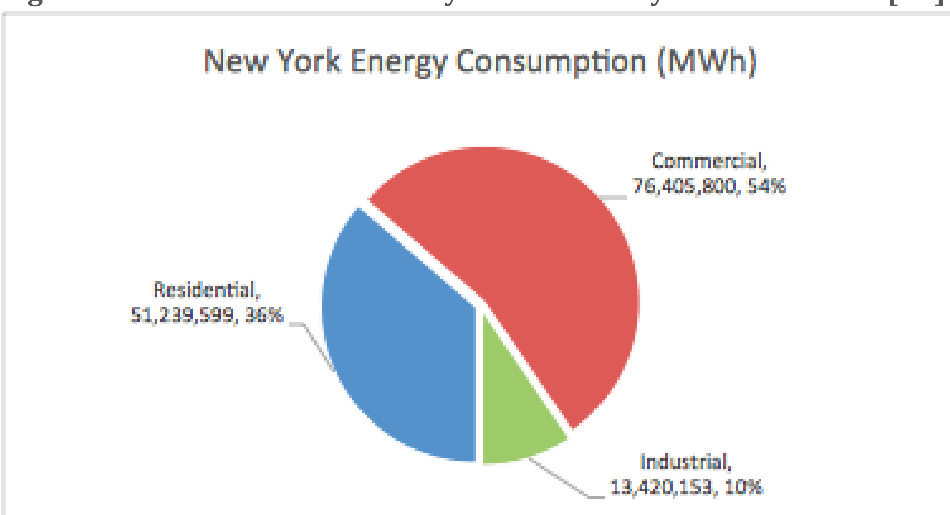


Figure 31 shows New York's 2011 electricity consumption by end-use sector. According to EIA, New York households consume an average of 103 million Btu per year (across all energy sources), 15% higher than the U.S. average.[84] However, electricity consumption in New York homes is lower than the U.S. average because most New York households use other fuels (e.g. natural gas) to meet major end use energy needs.

Figure 31: New York's Electricity Generation by End-Use Sector[92]



Distributed PV Penetration

As of 2012, New York had a cumulative 179 MW of grid-connected SPV capacity, ranking it tenth amongst U.S. states.[93] Of the state's 2012 total installed PV capacity, 98 MW of capacity resulted from installed net metering customers across the state.[94] Of the 98 MW of total SPV capacity across the state, 8,829 residential net metering customers accounted for 51 MW of generation while 1,952 commercial net metering customers accounted for 47 MW. Through its NY-Sun initiative, New York State is investing $800 million in SPV projects across the state through 2015 in partnership with New York State Energy Research and Development Authority (NYSERDA) and LIPA.[95] NYSERDA is a public benefits corporation that was originally founded in 1975, and is primarily funded by New York utility customers through a system benefits charge. NYSERDA's overall mission is to reduce energy consumption, promote the use of renewable energy sources, and protect the environment.[96]

Policies

The New York PSC established a 25% renewable portfolio standard in 2005, which has since been increased to 30%.[97] While New York State does not have a direct solar carve-out, according to DSIRE, SPV will account for approximately 8.44% of the state's annual incremental RPS requirement (0.58% of state sales in 2015).[98]

New York's investor-owned utilities are required to offer net metering to customers on a first-come, first-served basis, subject to technology, system size, and aggregate capacity limitations. Publicly owned utilities are not obligated to offer net metering. Systems eligible for net metering are limited to 25 kW for residential installations and 2 MW for non-residential. Overall, solar net-metered capacity may not exceed 1% of a utility's peak demand. Net excess generation of SPV is carried over at the utility's retail rate; all excess generation at annual reconciliation is paid at the avoided cost rate.[99] New York's current interconnection standard limits distributed generation sources to 2 MW. Interconnection is governed by a standard agreement, and is applicable to all investor-owned utilities in the state.

As of the time of this writing, LIPA opened its second solar feed-in tariff program to bring online 100MW of SPV capacity. The price that program participants will receive will be determined by a clearing price auction. Applicants to the program must submit a fixed-price bid for a 20-year agreement term. LIPA previously brought online 50 MW of SPV capacity through a feed-in tariff program that paid $0.22 per KWh.[97]

New York has generous state incentives for SPV deployment. An average 5 kW SPV system installed in New York receives approximately $8,750 in state rebates and incentives.[100] In addition to the 30% federal production tax credit (which expired in 2013), as of the time of this report, system owners in New York are eligible for a state tax credit of 25% of installation cost (up to $5,000). Additionally, New York residential SPV installations in New York are exempted from property taxes.[34] In New York City, building owners may deduct between 2.5% and 5% of SPV installation costs from their property taxes, annually, for up to four years—with a total tax benefit of up to 20% of the installed system cost.

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