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ALTERNATIVES TO NET METERING: A PATHWAY TO DECENTRALIZED ELECTRICITY MARKETS

L. Lynne Kiesling[1]

I. INTRODUCTION

The traditional regulated monopoly model for electric utilities is outdated and limits both innovation and product and service development in the power sector. One current example is the regulatory treatment of distributed energy resources (DERs). DERs are on-site energy sources that draw from any number of resources, including solar photovoltaics (PV), small wind, biogas and batteries. The crucial feature of these assets is that they are located on-site at homes or businesses. DERs create new types of operators in power markets who both purchase electricity from the grid and generate power from their own sources. These operators – who include industrial, commercial and residential customers – are referred to as customer-generators.

1. The author offers special thanks to Andrew N. Kleit of Penn State University for his insights and assistance in reviewing and improving this paper.

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At times, customer-generators generate more electricity from DERs than they use. In 46 states and the District of Columbia, this excess energy can be sold back to the utility, which then will make the power available to other customers through a process called net metering.[2] Net-metering regulations have been implemented since the 1970s to encourage renewable DERs, in part because they were simple to process, given non-digital metering. As more residential customers adopt DERs and receive payments through net metering, their increasing heterogeneity is exposing the tensions of attempting to integrate them into a regulatory framework designed for large-scale central power generation. That framework makes disentangling the economic and political effects of DER costs and benefits difficult. DERs impose costs by using the distribution network when DER owners sell excess generation;[3] they also confer benefits when they provide voltage and frequency regulation and other grid services to the network.

Reliance on net metering has driven recent controversies in several states, but the problems of net metering are structural problems of rate design.[4] Net metering's administratively determined prices fail to incorporate the local knowledge that would be reflected in market responses to price signals or changes in prices as system conditions change. Net-metering rates also obscure cross-subsidies inherent in traditional utility regulation, which often reveal themselves when new technologies change the energy-market opportunities that are of interest to consumers.

As DER technologies become more energy efficient, economical and attractive to residential customers, what is the appropriate rate structure for distribution-grid services? How can changes to rate design capture the opportunities available for DERs to generate electricity and provide other services outside of a regulated model? Open, competitive retail markets with low entry barriers to producers and consumers (and customer-generators) at a range of scales create those opportunities. A business model for the distribution utility as a market and distribution platform that connects them, and that procures resources for grid services through market transactions, would enable such value creation.

This paper analyzes the DER experience in the residential sector and suggests an alternative to current policy: open, transparent retail markets around the edge of a distribution platform, paying a grid-services charge to a distribution-wires-platform company. The paper also proposes a framework to develop an appropriate grid-services charge for customer-generators and analyzes case studies to apply that framework and derive lessons for policymakers.

2. Institute for Energy Research, "Net Metering 101," 2014. Available at http://instituteforenergyresearch.org/analysis/net-metering-101/. Accessed Aug. 10, 2015.

3. Lisa Wood and Robert Borlick, "Value of the Grid to DG Customers," Brookings Institution, 2013. Available at http://www.brookings.edu/research/reports/2013/10/01-value-of-grid-to-dg-customers-wood-borlick. Accessed Aug. 16, 2015.

4. Herman Trabish, "The Fight over Solar Moves from Net Metering to Rate Design," Greentech Media, Nov. 3, 2014. Available at http://www.utilitydive.com/news/the-fight-over-solar-moves-from-net-metering-to-rate-design/327742/. Accessed Aug. 24, 2015.

II. PRACTICE, THEORY AND A CRITIQUE OF CURRENT POLICY

Economic regulation of the power sector traditionally has focused on inexpensive universal electrification. For most of the 20th century, this focus meant the economies of scale and scope produced by large central-generation technology allowed us to achieve broad social benefits with relatively small economic distortion and inefficiency. Similarly, the relative homogeneity of residential customers meant the costs for electricity services were easily recovered through common bundled per-kilowatt-hour (kWh) retail rates.

Technology and policy priorities have put considerable pressure on this paradigm. Since the 1970s, the policy landscape that electricity regulators and utilities face has become multidimensional, with criterion-pollutant and greenhouse-gas regulations and an increasing appetite for customer choice. State regulators attempt to achieve multiple objectives with the set of traditional policy tools they possess: least-cost provision of cleaner electricity, in a world where electricity generation and consumption technologies are changing (both in type and in scale) more rapidly than bureaucratic policies can keep pace.

In the case of DER, net metering is an attempt to adapt traditional regulatory institutions to new policy objectives and technological dynamism. Simply put, traditional methods of rate-setting cannot appropriately capture the costs and benefits of consumer-owned DER.

Existing policy for DER customers

The legislative history of using net metering for DERs dates to the Public Utility Regulatory Policy Act (PURPA) of 1978.[5] PURPA required regulated utilities to buy from qualifying facilities (QFs) at the utility's avoided cost. The law was intended to encourage electricity generation using renewable sources and combined heat and power (CHP) at a larger scale than today's residential rooftop solar.

The federal Energy Policy Act of 2005 required distribution utilities to provide net metering to any customer that requested it. The 36 states that had adopted net metering by 2008 sought to revise this federal rule in order to encourage investment in renewables, stimulate economic growth,

5. Gregg Jarrell, "The Demand for State Regulation of the Electric Utility Industry," *Journal of Law & Economics* 21(2): 269-295, 1978.

encourage energy independence and diversify states' generation portfolios. Currently, 46 states and the District of Columbia allow some form of net metering within their jurisdiction; Alabama, Mississippi, South Dakota and Tennessee do not. Many of the states that allow net metering mandate participation by investor-owned utilities (IOU), who must pay for excess generation at a regulated rate. Municipal and cooperative utilities generally have no such requirement, although they can implement net metering if they choose.

Net-metering rules vary by state and sometimes by utility. Table 1 summarizes the variation in net-metering regulations across jurisdictions. Some net-metering regulations make only certain technologies eligible for the program, or they limit the per-unit capacity or total capacity that can be net metered in the system. Net-metering programs can also vary by the type of distribution utility and by the negotiated net-metering price paid to customer-generators.

TABLE I: SELECTED VARIABLES IN NET-METERING REGULATION

Policy Variation	Explanation	Example
Technology and fuel restrictions	States specify which technologies are eligible for net metering.	In Florida, solar PV may be net-metered, but landfill gas cannot.
Capacity limit	Some states have capacity limits for net-metered systems. Others do not. Some states design capacity limits relative to the customer-generator's consumption profile.	Hawaii's capacity limit is relative to the distribution circuit. New Hampshire allows systems up to 1MW to be net metered; in New Mexico, it's up to 80 MW.
Aggregate capacity	States will limit the total capacity of systems allowed to be net metered within a system.	In West Virginia, net-metered systems cannot exceed 3 percent of a utility's peak demand during the previous year
Net-metering by utility type	Some states require all IOUs to offer net metering, while exempting municipal utilities. There may be specific rules for different types of utilities.	In Colorado, net-metered IOU customers are capped at 120 percent of the customer's average annual consumption. For municipal and co-op utilities, net-metered systems must not exceed 10kW for residential.
Compensation	The majority of net-metered customers are compensated at a bundled retail rate. Some states have compensation at the wholesale energy rate.	Wisconsin Public Service Corp. net meters at the wholesale rate for some customers.

Source: EIA[6]

Under current net-metering rules in 29 states, the customer-generator is paid the full regulated retail rate for excess generation sold back to the utility. In many respects, this is both conceptually and logistically simple. In most cases, utilities sign an interconnection agreement with customers, and utilities cover the costs associated with interconnection and metering. Customers are billed as they normally would be, subtracting any electricity sold back into the distribution system.

Regulated retail rates

In traditional utilities regulation, regulators approve a price structure that is intended to compensate the utility at "least cost" for electric service. Utilities are reimbursed for their capital expenses, fuel costs and a return on investment reflecting the opportunity cost of capital, based on the following (albeit simplified) formula:

Retail electricity rate = fixed capital costs + variable fuel & operation costs + ROR

This regulated rate, assessed per-kWh of consumption, captures both fixed (capital) and variable (fuel and grid operation) costs. Fixed costs, such as transmission and distribution infrastructure, benefit all users of the grid, even those who rely on it only for backup generation. Variable operation costs include grid-services costs such as voltage and frequency support and grid balancing, separate from the energy-specific cost that varies with demand.[7]

This combination of cost recovery and sharing of costs across customers works when customers in a particular class are broadly similar in size and consumption (e.g., traditional residential customers).

Options for net metering

Using a bundled retail rate for net metering reflects both compromise and convenience. In traditionally regulated states, the utility remains vertically integrated, limiting its ability or incentive to distinguish among the types of costs captured in the bundled retail rate. The retail rate and electric meters that run backward were relatively inexpensive ways to enable net metering. The more recent proliferation of sophisticated digital-metering technology enables alternative pricing approaches for DER energy sales and payments for grid services, as these technologies reduce the transaction costs to measure excess generation.

Some utilities require two separate meters or a bi-directional meter for net-metered customers, capturing electricity consumption and sales of electricity to the grid separately. By distinguishing inflows and outflows, separate and bi-directional meters allow utilities to pay the customer-generator

6. Energy Information Administration, "Policies for Compensating Behind-the-Meter Generation Vary By State," Today in Energy, May 9, 2012. Available at http://www.eia.gov/todayinenergy/detail.cfm?id=6190. Accessed Aug. 24, 2015.

7. David Brown and David Sappington, "On the Design of Distributed Generation Policies: Are Common Net Metering Policies Optimal?" Working paper, University of Alberta, February 2015. Available at http://people.clas.ufl.edu/sapping/files/Net-Metering-JIE.pdf. Accessed Sept. 4, 2016.

a rate that differs from the bundled retail rate for excess generation.

The specific net-metering rates determined by regulators have implications for infrastructure and capacity investment. If residential customers only receive the long-term avoided energy cost per kWh of excess generation, they will expect lower returns on investment in DER systems and would be less likely at the margin to make those investments. If the policy is intended to foster cleaner electricity generation, setting a net-metering price at this lower bound reduces the likelihood to meet that objective, primarily attracting only those customers with more intense preferences for environmental quality. Striking a reasonable balance between economic and environmental objectives has led regulators generally to set the controlled net-metering price at the residential retail rate.

Controversies and cross-subsidies

The net-metering approach has exposed considerable new cross-subsidies between customer-generators and traditional customers. When compensated for excess generation at the bundled retail rate, customer-generators are not paying for the infrastructure costs and grid services associated with their excess generation outflow, even though that outflow uses the distribution infrastructure and grid services. Compensating customer-generators at energy-only rates fails to account for distribution, reliability and grid-services costs and benefits. They also are not being paid explicitly for providing grid services such as balancing and voltage and frequency support. Although that capability is limited technologically at the moment – because DERs are not really dispatchable or able to control flow algorithmically – not accounting for these contributions guarantees that DERs will not develop to take on that role.

The advent of residential DERs also makes residential customers as a group more heterogeneous and exposes the weaknesses of regulated rate-setting. This increasing heterogeneity, in concert with net-metering regulations that were based on a bundled retail rate, creates cross-subsidies that did not exist or were substantially smaller before the digital and DER innovations.[8] While the value and direction of the cross-subsidies are not always obvious, it's clear that the fully bundled retail rate obscures those costs and fails to send transparent price signals to both customers and utilities at the margin.

From the utility's perspective, paying the bundled flat retail rate reimburses customer-generators for the costs of distribution and grid services, even though they use the wires and the distribution system to sell and distribute their excess energy. As a recent interdisciplinary study of solar technologies and policies from the Massachusetts Institute of Technology puts it:

> …most U.S. utilities bundle distribution network costs, electricity costs, and other costs and then charge a uniform per-kWh rate that just covers all these costs. When this rate structure is combined with net metering, which compensates residential PV generators at the retail rate for the electricity they generate, the result is a subsidy to residential and other distributed solar generators that is paid by other customers on the network.[9]

In their model of an optimal price to pay for distributed generation, David Brown and David Sappington[10] find that, under fairly general conditions, the optimal price is less than the retail rate, due to the distribution and grid-services costs associated with DERs.

Robert Borlick and Lisa Wood, in a paper for the Institute for Electric Innovation, present a utility-oriented analysis of the subsidy embedded in net metering:

> Today, when a DG customer produces on-site energy, this correspondingly reduces the amount of energy the customer purchases from the local utility, thereby avoiding payment of that portion of the energy rate in the customer's retail tariff that is designed to recover the customer's contribution to the utility's fixed costs. This is the source of the NEM subsidy – it is the direct result of the energy rate in a customer's retail tariff exceeding the utility's avoided energy cost. In our analysis, we define the NEM subsidy as the difference between the customer's bill savings due to the on-site energy production and the utility's costs avoided by not having to deliver the electricity displaced by the energy produced on-site.[11]

Their net-present-value analysis suggests a typical customer-generator in southern California (in Southern California Edison territory) would earn a 17 percent after-tax rate of return and have a payback period of seven years. While they do not report a per-kWh or per-kW of capacity grid cost that is shifted, and their estimate also includes the federal investment tax credit as well as net metering, their estimated rate

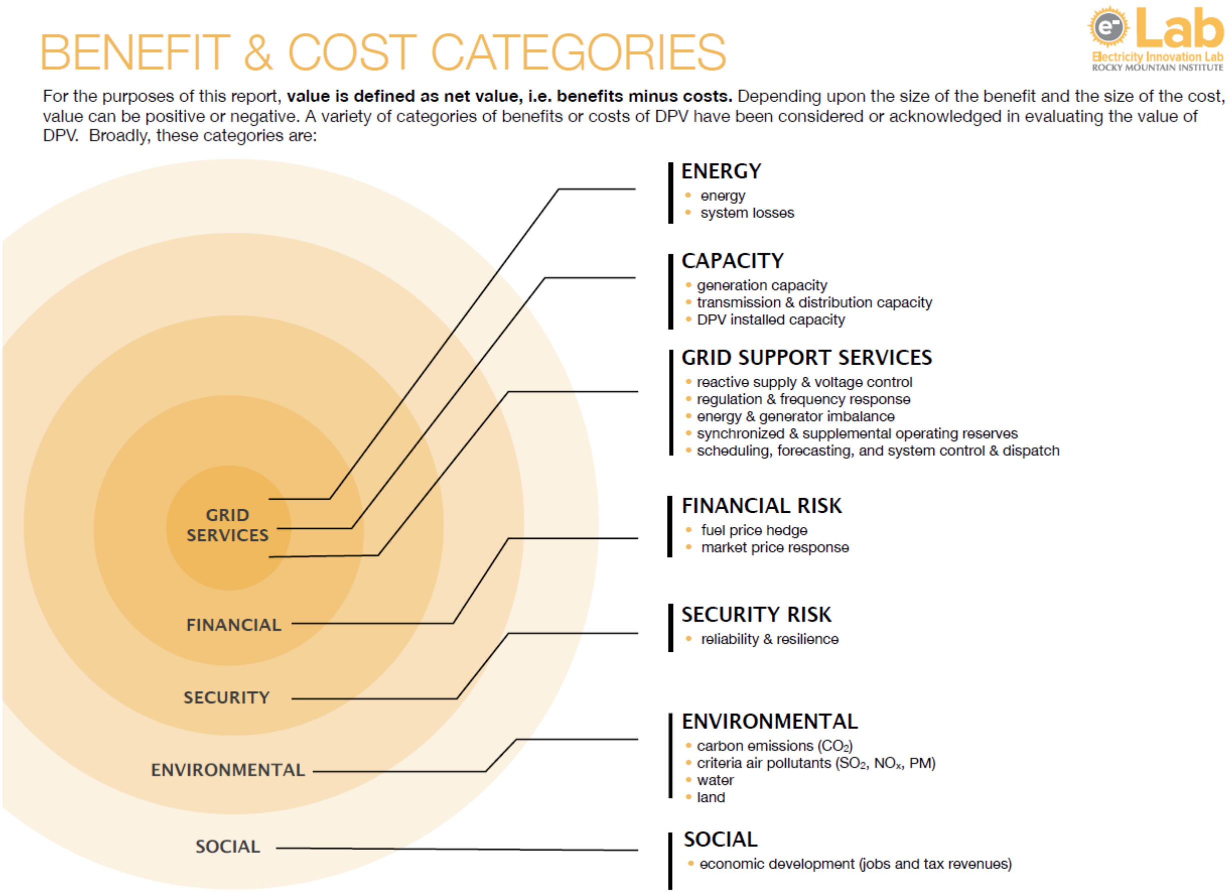
8. Lynne Kiesling, "Implications of Smart Grid Innovation for Organizational Models in Electricity Distribution," M. Pollitt, ed., *Wiley Handbook of Smart Grid Development*, London: Wiley, 2015.

9. Massachusetts Institute of Technology (MIT), "The Future of Solar Energy," p. xviii; see also p. 111 and Chapter 7, available at https://mitei.mit.edu/futureofsolar. Accessed Aug. 28, 2015.

10. Brown and Sappington, 2015

11. Robert Borlick and Lisa Wood, "Net Energy Metering: Subsidy Issues and Regulatory Solutions," Edison Foundation, Institute for Electric Innovation, p. 1, 2014.

FIGURE I: CATEGORIES OF PHYSICAL AND ECONOMIC IMPACTS OF DERS



Source: Hansen et. al. (2013), p. 13

of return and payback period indicate above-normal profits to customer-generators from those two programs.

Distribution utilities, concerned about covering costs and earning their regulated rate of return, see this rate structure as having embedded cost-shifting that threatens their financial viability.[12] They have proposed rate changes, including lower energy payments, higher fixed charges to customers and DER-specific demand charges per kilowatt-hour (kWh) sold back.[13] Such rate proposals unwind the traditional rate-making practice of the distribution utility recovering distribution operating costs and infrastructure fixed costs by charging a bundled per-kWh rate.

However, the results of a meta-study by the Rocky Mountain Institute suggest some subsides flow in the other direction.[14] Figure 1 indicates the seven categories of benefits and costs in which increasing DERs have an impact. They can contribute to avoided capacity investment, avoided line losses, lower electricity prices through decentralized competitive markets, lower security risks through decentralized resilience and lower environmental impact of electricity generation and consumption.

Lindsey Hallock and Rob Sargent of the Environment America Research & Policy Center[15] find similar results in their meta-study of the benefits and costs of rooftop solar PV specifically. Studies that took into account the environmental benefits of solar, increased resiliency and reduced financial risks and electricity prices concluded that the value of solar was higher than the avoided energy and capital costs.

12. Joby Warrick, "Utilities Wage Campaign against Rooftop Solar," Washington Post, March 7, 2015. Available at https://www.washingtonpost.com/national/health-science/utilities-sensing-threat-put-squeeze-on-booming-solar-roof-industry/2015/03/07/2d916f88-c1c9-11e4-ad5c-3b8ce89f1b89_story.html. Accessed Aug. 26, 2015.

13. Herman Trabish, "Solar's Net Metering under Attack," Greentech Media, May 3, 2012. Available at http://www.greentechmedia.com/articles/read/solars-net-metering-under-attack. Accessed Sept. 1, 2015.

14. Lena Hansen, Virginia Lacy and Devi Glick, "A Review of Solar PV Benefit and Cost Studies," Rocky Mountain Institute, 2013. Available at http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue. Accessed Aug. 20 2015.

15. Lindsey Hallock and Rob Sargent, "Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society," Environment America Research & Policy Center, June 2015. Available at http://environmentamerica.org/sites/environment/files/reports/EA_shiningrewards_print.pdf. Accessed Nov. 6, 2015.

Andrew Satchwell and a team of researchers at Lawrence Berkeley National Laboratory[16] estimate a financial model for two prototype utilities, comparing a case with customer-sited PV penetration from 2.5 percent to 10 percent of retail sales over 20 years with the benchmark of no customer-sited PV. They estimate retail rates would increase by 0.1 percent to 2.7 percent as the share of PV increases, depending on other parameters in the model (e.g., total demand growth). These estimates across all residential customers do not measure cost-shifting directly, although some cost-shifting is certainly occurring and the implied magnitude thus far is not large. As in the RMI meta-study, they also find increased DER shares create benefits as well as costs.[17] Their policy implications point to the importance of rethinking rate design in a period of technological change and to political trade-offs that are likely to be challenging:

> At a minimum, the magnitude of the rate impacts estimated within our analysis suggest that, in many cases, utilities and regulators may have sufficient time to address concerns about the rate impacts of PV in a measured and deliberate manner. Second and by comparison, the impacts of customer-sited PV on utility shareholder profitability are potentially much more pronounced, though they are highly dependent upon the specifics of the utility operating and regulatory environment, and therefore warrant utility-specific analysis. Finally, we find that the shareholder (and, to a lesser extent, ratepayer) impacts of customer-sited PV may be mitigated through various "incremental" changes to utility business or regulatory models, though the potential efficacy of those measures varies considerably depending upon both their design and upon the specific utility circumstances. Importantly, however, these mitigation strategies entail trade-offs – either between ratepayers and shareholders or among competing policy objectives – that may ultimately necessitate resolution within the context of broader policy- and rate-making processes, rather than on a stand-alone basis.[18]

Although these analyses are not definitive, they illustrate the range of practical issues arising from the general regulatory concept of an embedded cross-subsidy and illustrate some of the challenges and controversies facing the states (see more on this in Section III).

16. Andrew Satchwell, Andrew Mills, Galen Barbose, Ryan Wiser, Peter Cappers and Naim Dargouth, "Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities," Lawrence Berkeley National Laboratory LBNL-6913E, September 2014.

17. Hansen, et al., 2013.

18. Satchwell, et al., 2014, p. xiv.

Shifting economics of DER

The relatively rapid installation of DER in some regions, facilitated by the changing economics of distributed solar energy, has led to greater scrutiny of cross-subsidies associated with existing net-metering programs. Innovative financing and business models have combined with net-metering policies and the reduction in PV system costs to drive growth in the residential solar market and its share of the DER portfolio.[19]

The installed cost of distributed PV fell 44 percent between 2009 and 2014, with distributed solar installations comprising 31 percent of all electric power installations completed in 2013.[20] In that same year, overall residential solar PV capacity increased 68 percent across the nation. California led this growth, with a 161 percent increase in 2013.[21] The U.S. Department of Energy estimates that installed prices of solar decreased by 6 to 7 percent per year from 1998 to 2012, but by 12 to 15 percent from 2012 to 2013.[22]

The residential solar industry also has seen financial innovation, largely in the form of third-party ownership of solar PV systems to reduce the debt and capital costs to the homeowner. Third-party ownership allows developers to cover most installation, equipment, operations and maintenance expenses, with those costs repaid over time through the sale of electricity directly to the customer-generator using a power purchase agreement (PPA). Another financing innovation has been solar loans, which resemble PPAs but allow homeowners to own the solar panels and take advantage of the 30 percent federal production tax credit.

State policies also affect patterns of DER growth. Over the past two years, Arizona and California have led in residential solar system installations. Both states have relatively high retail prices and set the net-metering price at the bundled retail rate. Econometric analysis of residential PV capacity (detailed in this paper's Appendix) reinforces the argument that the retail price and the net-metering price are the two main economic and policy variables influencing residential solar PV capacity decisions.

In some locations, increasing numbers of customer-generators are causing some rate-design tensions to surface. These

19. MIT 2015, p. 10

20. Nicholas Franco, "2013 Solar Trends Update," *Trending Energy*, May 12, 2014. Available at http://www.trendingenergy.com/2013-solar-trends-update/. Accessed Aug. 26, 2015.

21. Lynne Kiesling and Mark Silberg, "Regulation, Innovation and Experimentation: The Case of Residential Rooftop Solar," *Annual Proceedings of the Wealth and Well-Being of Nations*, 2015.

22. Barry Friedman, Kristen Ardani, David Feldman, Ryan Citron, Margolis Robert and Jarett Zuboy, "Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition." National Renewable Energy Lab.

tensions illustrate the economic theory underlying net-metering rate design and criticisms of it.[23] The recent MIT interdisciplinary study summarizes the issues well:

> Net metering compensates these generators at the retail price for electricity they supply to the grid, not at the wholesale price received by grid-scale generators. A large fraction of the cost of running a distribution system is fixed, independent of load, but much or all of this fixed cost is generally recovered from retail customers through a per-kWh distribution charge. When a residential customer installs a rooftop PV generator, that customer's distribution charge payments are reduced. But there is no corresponding reduction in the distribution utility's distribution system costs. As noted in Chapter 7, the subsidy is the corresponding reduction in the utility's revenues, which may be made up by increasing the retail price paid by all customers.
>
> …Moreover, because the distribution utility pays this subsidy, it has strong incentives to make it hard to install distributed generation. So-called decoupling arrangements in some states deal with this problem by automatically increasing per-kWh distribution charges so as to maintain utility profits. But this shifts the burden of covering distribution costs from utility shareholders to those customers who do not or cannot install distributed generation, a group that is likely to be less affluent than those who benefit from net metering.49 Even at the current relatively low penetration of residential solar, this cost shifting has become controversial in many states. It seems unlikely that the much larger cost shifts that would be induced by substantial penetration of residential solar with net metering would generally be politically acceptable.[24]

Arizona has been a testing ground for this controversy. Arizona retains a traditional regulatory structure, with fully regulated, vertically integrated IOUs. Customer-generators receive the bundled retail rate per kWh for their excess generation and are paid for any remaining kWh credits in the annual "true-up period" at the utility's estimated avoided cost.[25]

With the growth of residential rooftop solar over the past five years, Arizona utilities became increasingly concerned that the bundled retail net-metering rate shifted too many grid-related costs to customers who don't use net metering. They also have been motivated by concerns that increasing DER ownership would reduce their revenues and require them to charge increasing prices to recover their costs.[26]

IOUs in Arizona asked the regulator, the Arizona Corporation Commission (ACC), to approve a fixed charge for net-metered customers to mitigate this cost shift. In November 2013, the commission approved a fixed charge of $0.70 per kilowatt (kW) of installed capacity. This charge added about $5 to a typical monthly bill and was substantially smaller than the charge the utilities had requested.[27]

Recently, the state-owned Salt River Project (SRP) power company also changed its retail rates, implementing a new demand charge for net-metering customers that could add $50 to a monthly bill.[28] Tensions over the use of and payment for the distribution grid have grown as DERs have become a larger share of the energy portfolio in Arizona and elsewhere.

The rapidly changing economic calculus for residential customers further suggests some questions about policy objectives. First, lower technology and opportunity costs reduce the economic justification for artificial encouragement of DERs to meet ancillary policy objectives. Continuing net-metering regulation may be unnecessary to achieve consumer choice or environmental objectives.

Second, to the extent that net-metering customers have higher than average incomes, cross-subsidies may shift costs away from wealthier customers and toward poorer customers. Utilities have used this argument to suggest that net metering has undesirable regressive distributional consequences.[29]

Finally, a net-metering subsidy may also be an inefficient way to meet environmental policy objectives. Evaluating distributed residential DERs solely on a cost basis indicates they are more costly, in terms of capital costs and system operation costs, than utility-scale solar.[30] But restricting the evaluation criteria to accounting costs may not be entirely appropriate.

23. Julie Burger, Christopher Field, Richard Norgaard, Elinor Ostrom and David Policansky, "Revisiting the Commons: Local Lessons, Global Challenges," Science 284.5412, pp. 278-288, April 9, 1999.

24. MIT 2015, p. 219

25. Database of State Initiatives for Renewable Energy (DSIRE), "State Net Metering Profile: Arizona," available at http://programs.dsireusa.org/system/program/detail/3093. Accessed Aug. 19, 2015.

26. Edison Electric Institute, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," available at http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf. Accessed June 21, 2015.

27. Bill Sweet, "Arizona Imposes Net Metering Fee on Rooftop Solar," IEEE Spectrum, Nov. 19, 2013. Available at http://spectrum.ieee.org/energywise/green-tech/solar/arizona-imposes-net-metering-fee-on-rooftop-solar. Accessed Aug. 10, 2015.

28. José Javier Angulo, "The Unexpected Consequences of Net Metering: The Case of Solar Power in Arizona," working paper, Property and Environment Research Center, 2015.

29. Robert Borlick and Lisa Wood "Net Energy Metering: Subsidy Issues and Regulatory Solutions," Edison Foundation, Institute for Electric Innovation, p. 3, fn 2, 2014; See also Brown and Sappington, 2015, p. 4.

30. MIT 2015, Chapters 4-5

If residential customers get sufficient value, both monetary and non-pecuniary, from satisfying their subjective preferences by installing DERs, that suggests a value-based criterion for evaluating DERs compared to utility-scale solar.

Regulatory policy has been cost-based in electricity for more than a century. In a period of rich technological change and new value creation, too much focus on cost recovery and not enough on reducing barriers to value creation is unlikely to make consumers better off and unlikely to serve the public interest.

Value of DERs

DERs convey many benefits, both monetary and non-pecuniary and both to their owners and to the electric system. Customer-generators benefit from lower electricity bills, from the benefits of having a backup source of energy from the grid and from being able commercially to satisfy preferences to use cleaner energy. Both customer-generators and utilities benefit from the role of DERs as a hedge against fluctuations in fuel prices.

Traditional vertically integrated utilities benefit from reduced energy purchases (short-term avoided cost) and from reduced investment in generation, transmission and distribution infrastructure (long-term avoided capacity cost). Traditional utilities may also use customer-generated renewables to meet state renewable portfolio standard and similar environmental regulation targets. If the DERs are dispatchable, utilities would benefit from being more able to use distributed energy to provide ancillary grid services, balancing services, voltage and frequency support and reactive power. Overall, DERs also contribute to grid resiliency and the ability to absorb or recover from a natural emergency or a terrorist attack, as well as reducing emissions associated with fossil-fuel combustion to generate electricity.

These benefits come with associated costs. Most of these costs are borne by the utility, not the customer-generator, when the regulated net-metering price is the fully-bundled retail rate. In the short term, customer-generators still use the distribution grid in two states of the system:

1. When they are buying in energy generated elsewhere; and
2. When they are selling back energy they have generated themselves.

In the state in which they are self-supplying, they are not directly using the grid, but rely on the grid as insurance in case of unexpected failure. Across 14 existing studies, DERs create net benefits in eight cases. Several of those studies take into account estimates of environmental and social benefits that are difficult to quantify.[31]

Jason Keyes and Karl Rábago of the Interstate Renewable Energy Council[32] highlight the difficulty of estimating benefits and costs of DERs, as well as the magnitude of the subsidy embedded in net metering. Such estimates are necessarily done at the utility level and, as such, are highly contextual.

The Rocky Mountain Institute meta-study[33] surveyed existing analyses of the benefits and costs of increased DER shares. Not all studies estimated both benefits and costs and several of the categories of impacts are qualitative and difficult to quantify. Nonetheless, the study provides a valuable taxonomy of the economic and physical impacts of DERs through which they can yield benefits and costs.

One way to think about DER use of the distribution grid is to look at the intertemporal mismatch of customer-generators' inflows and outflows of energy. When self-generation exceeds demand, customer-generators use the distribution grid as a battery. When demand exceeds self-generation, they use it to receive energy. Energy flows on the grid from distributed locations can be absorbed and balanced if the DERs are a small enough proportion of the energy portfolio. Balancing is harder and more expensive as that proportion rises. Balancing the network is the main operational cost that varies as the share of DERs on the grid changes.

Intermittency and non-dispatchability of DERs exacerbate that problem. DERs typically put energy on to the distribution grid when the energy is generated, with no ability to store or "throttle" it. Balancing requirements and costs increase to keep the grid physically stable. Declining prices and increasing availability of battery-storage technology in electric vehicles and as stand-alone devices may enable throttling in the future. The long-term infrastructure implications of increased DER shares are that distribution companies must make investments to maintain, improve and/or expand the capacity of the distribution grid. Because most costs of grid services are borne by the utility, under traditional rate design, those costs are allocated similarly across all residential customers and are bundled in the per kWh retail rate.

Another challenge that DERs present on a distribution grid is both short-term and long-term: the architecture of the grid is not suited to bi-directional energy flow. The distribution

31. Hansen, et al., 2013, p. 22.

32. Jason Keyes and Karl Rábago, "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," Interstate Renewable Energy Council, available at http://votesolar.org/wp-content/uploads/2013/09/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG1.pdf. Accessed Aug. 16, 2015.

33. Hansen, et al., 2013.

grid was designed to accommodate one-way energy flow from generators to consumers, mediated by substations, transformers, mechanical switches and insulators. This structure was built at a time when grid-tied distributed generation and bi-directional flow were occasional and small engineering challenges. Most distributed generation existed in the context of industrial and commercial self-generation with grid backup, not in the context of highly decentralized bi-directional flow. Accommodating such flows will require rethinking the architecture of distribution grids, redesigning networks and making capital investments to implement the redesigned architectures.

Net-metering regulation highlights the insufficiency of underlying rate design to account for the full complement of grid services.[34] Carl Linvill, John Shenot and Jim Lazar provide a useful discussion of DER benefits and costs and some of the ratemaking principles to apply when considering alternatives to net metering. The costs and benefits of DERs cannot be captured appropriately, as they remain contextual, system-specific, location-specific and beyond the accounting tools of current rate-setting.

Clear need for an alternative model

The opacity of DER benefits and costs, and the tensions that arise from increasing DER penetration in an administratively determined regulatory pricing environment, indicate the clear need for an alternative model. That model should exploit the dramatic transaction cost reductions from digital technology, along with the cost reductions of DERs, to make DER benefits and costs transparent. It should enable DER owners to capture those benefits, which would induce them to invest in doing so. Making this possible will require a more transparent and adaptable framework to determine prices.

Technological changes have made decentralized markets feasible and attractive. Decentralized market platforms are more compatible with both quantitative and qualitative value creation from DERs. Combined with the decline of both solar PV costs and smart grid-enabled transaction costs, alternatives to regulated pricing structures are preferable.

Regulated rate-setting mutes price signals and prevents the communication of important but diffuse knowledge that price signals can accomplish. This restriction contributes to static and dynamic inefficiency by limiting the resource allocation process that goes on in market exchange and obscures the dynamic entrepreneurial opportunities available to innovators and investors.

34. Carl Linvill, John Shenot and Jim Lazar, "Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition," Regulatory Assistance Project, pp. 26-30, November 2013.

Net-metering regulation entrenches the mismatch between value and cost and provides a poor substitute for actual price signals that emerge from decentralized market exchange. A traditional bundled rate and restructured two-part rates both fail to send sufficiently informative price signals. Setting the net-metering rate at the energy-only rate would make the energy portion of the price signal clearer. However, if the remaining charge is fixed, and if those fixed charges are the same for all residential customers, they will not send clear price signals about grid services to customer-generators.

This entrenchment means the prices paid and charged and the contracts offered do not adapt smoothly to unanticipated changes. These include the technological changes that have made DERs more economical for residential customers and the "smart grid" technological changes that make interconnection, automation and transactional exchange among distributed customer-generators cheaper and easier.

Further, this critique starts from the assumption that the benefits and cost of DERs are subjective; that is, each individual has a personal, private, set of preferences and opportunity costs when comparing DERs to other energy alternatives. Knowledge about the benefits and costs of DERs is diffuse, private and heterogeneous, embedded in the subjective valuations of each person. For that reason, the accounting costs that usually make up the basis for calculating the benefits and costs of DERs and net metering are not the only considerations going into prices.

Prices are knowledge surrogates that enable coordination of peoples' plans across their different perceptions of preferences and costs, across time and space. Net-metering regulation, with a bureaucratically controlled price, cannot reflect all the knowledge of the "man on the spot" that is captured in how people respond to prices and how price changes emerge in market exchange. As the Nobel laureate Friedrich Hayek put it in one his most famous essays:

> If we can agree that the economic problem of society is mainly one of rapid adaptation to changes in the particular circumstances of time and place, it would seem to follow that the ultimate decisions must be left to the people who are familiar with these circumstances, who know directly of the relevant changes and of the resources immediately available to meet them. We cannot expect that this problem will be solved by first communicating all this knowledge to a central board which, after integrating *all* knowledge, issues its orders. We must solve it by some form of decentralization. But this answers only part of our problem. We need decentralization because only thus can we ensure that the knowledge of the particular circumstances of time and place will be promptly used. But the "man on the spot" cannot decide solely

> on the basis of his limited but intimate knowledge of the facts of his immediate surroundings. There still remains the problem of communicating to him such further information as he needs to fit his decisions into the whole pattern of changes of the larger economic system.[35]

By aggregating and communicating diffuse private knowledge of myriad individuals making consumption, production and investment decisions, the price system does the best feasible job of making that diffuse knowledge available to every "man on the spot" in society.

The coordination that occurs through market processes is also more flexible and more resilient than the outcome based on net-metering regulation. Exchanges made in response to price signals enable individual parties to adapt to unknown and changing conditions, including the physical conditions of distribution systems and associated operating costs. Net-metering regulation rigidifies grid-services cost allocations. As the proportion of DERs in the energy portfolio change, those system costs and benefits change in ways that are idiosyncratic and cannot be reflected in the pre-determined net-metered price.

Prices that emerge from a market-exchange process, as described above, may still not fully reflect the environmental costs associated with fossil-fuel combustion. Market processes are no more perfect in a world of ill-defined property rights than political processes. But these market processes will do a better job of aggregating diffuse, private knowledge among customer-generators, entrepreneurs and other participants in the retail electricity market. Digital smart-grid technologies are transactive. This makes it easier and cheaper to exchange through open retail electricity markets, rather than relying on a single price from a single buyer for excess energy from DERs. Such markets are the superior and increasingly feasible alternative to administered pricing through net-metering regulation imposed over the existing rate structure.

The costly policy challenges and the cross-subsidies created as part of net-metering regulation highlight the problem of regulated rate design in a time of technological dynamism. An alternative institutional design should include an open retail market, an updated utility business model and a rate design for distribution and grid-services costs for a decentralized and technology-embedded network.

35. F. A. Hayek, "The Use of Knowledge in Society," *American Economic Review* 35(4): 519-530.

III. EXPERIENCE IN THE STATES

Developing appropriate policies to value DERs and compensate customer-generators will be left to the states. The different regulatory structures and limitations the states adopt shape how dynamic technological change leads to changes in power markets. These case studies examine tensions arising from some of net metering's intended and unintended consequences within the traditional regulatory framework and echo similar policy battles occurring in other states.

In the second quarter of 2015, 32 separate fixed-charge proposals were filed across 18 states.[36] In five states, utilities proposed increasing charges specifically for customers with distributed generation, although one was rejected in New Mexico and the others are ongoing.[37] In states that retain a regulated power market, utilities and customer-generator interests are locked in a debate between whether the DERs and net metering impose higher costs on traditional customers or whether they provide sufficient deferred investment, diffuse grid services and environmental benefits to outweigh those costs.

In this paper, we examine two traditional regulated markets (Nevada and Wisconsin); the hybrid model in California; and Texas, the only fully deregulated market. These case studies show that, as net metering has expanded, challenges to cost-shifting have been extensive in traditional vertically integrated states. Through its deregulation legislation and ensuing market design and policymaking, Texas has unbundled traditional regulated retail rates and has not mandated net metering. Despite its lack of mandates, Texas is seeing a residential solar market emerge organically, as production costs have fallen and financial innovations have occurred.

Traditional regulated model: Nevada

Nevada retains a traditional vertically integrated industry and regulatory structure and has had net-metering legislation since 1997. Nevada's net-metering regulations have been revised several times. Recent changes made in December 2015 transformed the nature of net metering and the residential solar industry in the state and will certainly influence how DERs generally, and residential solar in particular, continue to evolve.

Before the recent changes, any DER up to 1MW was eligible for net metering. For installations with capacities between 25kW and 1MW, the utility was permitted to

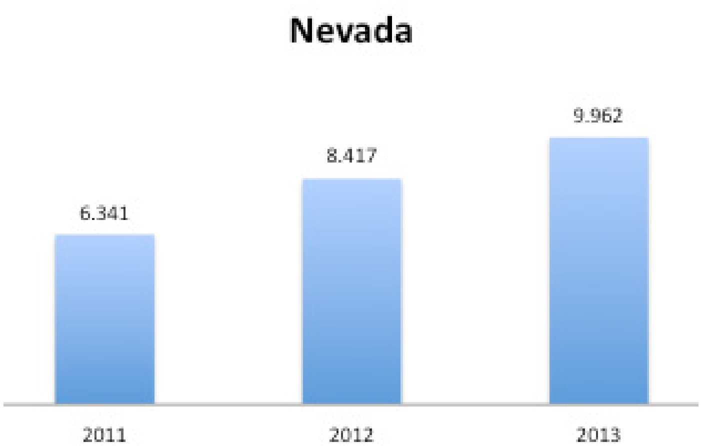
36. North Carolina Clean Energy Technology Center (NCCETC), "50 States of Solar, Q2 2015," pp. 25-26, available at http://nccleantech.ncsu.edu/wp-content/uploads/50-States-of-Solar-Q2-2015-final.pdf. Accessed Aug. 19, 2015.

37. NCCETC 2015, p. 34.

impose additional costs "at the utility's discretion."[38] Residential DERs eligible for net metering were required to be intended for self-supply and sized accordingly, and received a bi-directional meter. The aggregate statewide cap on net-metering capacity had been 3 percent of peak capacity until June 2015, when it was revised to a flat cap of 235MW. That cap was exceeded in August 2015.[39]

Customer-generators received a bundled retail rate for excess generation, with excess generation credits carried over indefinitely. Nevada has historically restricted fixed fees and other charges to net-metering customers up to 25kW capacity: "The utility may not charge these customer-generators any fee that would increase their minimum monthly charges to an amount greater than that of other customers in the same rate class."[40]

FIGURE 2: INSTALLED RESIDENTIAL SOLAR PV CAPACITY IN NEVADA, MW, 2011-2013



Source: EIA Form EIA-826[41]

Compared to the other states, Nevada has experienced an unusual amount of negotiation and debate over the degree with which the Legislature retains jurisdiction over net-metering rules, rather than the PUC. The main issues are conceptually the same as in other traditionally regulated states with net-metering: utilities are concerned about their costs of serving customer-generators and their future revenue streams. They align those concerns with and express them as an effort to protect non-generating residential customers from cost-shifting, due to the common cost allocations embedded in the traditional retail tariff.[42] Customer-generators and distributed-energy companies are concerned that new rules will impose undue costs and squeeze new DER investments out of the market.

With the impending fulfillment of the existing aggregate cap on net-metering capacity, in June 2015 the Nevada Senate passed S.B, 374. In addition to changing the definition of the aggregate cap, the bill directed the Nevada PUC to implement new post-cap net-metering rules and the state's utilities to file new net-metering tariff proposals with the PUC by the end of July 2015. NV Energy, an IOU, filed a proposal to pay a lower net-metering rate and charge customer-generators a fixed charge.[43]

Despite a July 2014 study on the impacts of net metering in the state that found cost shifts to be fairly small,[44] the PUC implemented new rules that will transition all net-metering customers to a cost-based rate structure. The new structure will compensate customer-generators at the wholesale market rate for excess generated power, increase fixed charges and implement time-of-use pricing options. This change moves net-metering customers from a bundled to an energy-only rate.

Traditional regulated model: Wisconsin

Wisconsin retains a traditional regulatory structure, with fully regulated vertically integrated utilities. All DERs are eligible for net metering up to 20 kW of installed capacity and customer-generators receive the bundled retail rate for their excess generation.[45]

As a result of utility concerns about the financial impact of increased penetration of DERs in Wisconsin, three IOUs (Wisconsin Public Service Co., We Energies and Madison Gas & Electric) presented rate cases in 2013 and 2014 that included provisions to increase the fixed-charge components of residential retail rates. In November 2014 the Wisconsin Public Service Commission approved increased fixed charges (to all residential customers, not just to customer-generators) and reduced net-metering payments for customers of

38. Database of State Initiatives for Renewable Energy (DSIRE), "State Net Metering Profile: Nevada," available at http://programs.dsireusa.org/system/program/detail/372. Accessed Aug. 26, 2015.

39. Julia Pyper, "Nevada PUC Decides to Keep Net Metering in Place Through 2015," Greentech Solar, Aug. 26, 2015. Available at https://www.greentechmedia.com/articles/read/nevada-puc-votes-to-keep-net-metering-in-place-through-2015. Accessed Aug. 26, 2015.

40. DSIRE-NV, 2015.

41. Energy Information Administration (EIA), Form EIA-826 Detailed Data, available at http://www.eia.gov/electricity/data/eia826/. Accessed Aug. 7, 2015.

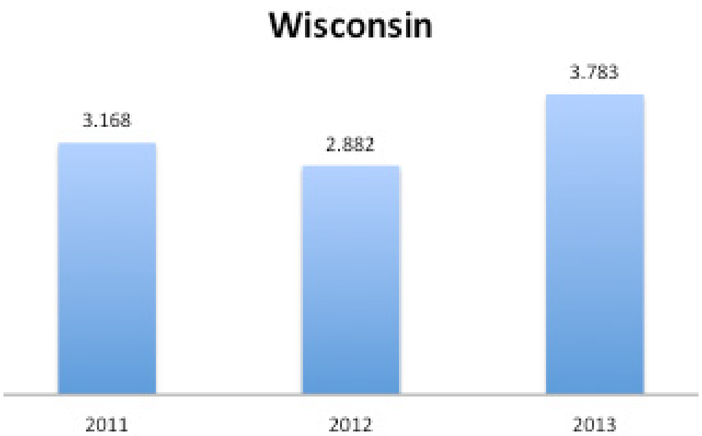
42. Gautham Thomas and Kyle Roerink, "NV Energy Fights to Keep Rooftop Solar from Cutting into Its Profit," *Las Vegas Sun*, May 25, 2015. Available at http://lasvegassun.com/news/2015/may/25/nv-energy-fights-rooftop-solar-cutting-into-profit/. Accessed Aug. 26, 2015.

43. Pyper 2015.

44. Snuller Price, Katie Pickrell, Jenya Kahn-Lang, Zachary Ming and Michele Chait, "Nevada Net Energy Metering Impacts Evaluation," Available at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study. Accessed Nov. 3, 2015.

45. Database of State Initiatives for Renewable Energy (DSIRE), "State Net Metering Profile: Wisconsin," available at http://programs.dsireusa.org/system/program/detail/235. Accessed Aug. 19, 2015.

FIGURE 3: INSTALLED RESIDENTIAL SOLAR PV CAPACITY IN TEXAS, MW, 2011-2013



Source: EIA Form EIA-826

the three IOUs.[46] News coverage noted: "According to We Energies, the higher fixed monthly charges and solar fees were necessary to offset revenue losses as customers go solar and become more energy-efficient, thus buying less power from the utility."[47] In all three cases the rate structure changed by increasing the fixed charge and decreasing the variable (energy) charge on all residential customers. This reflected an effort to reverse a common trend in vertically integrated utility ratemaking over the past century of trying to recover some portion of fixed costs through the volumetric variable energy charge.[48]

Hybrid model: California

After its poorly designed attempt at regulatory restructuring in the late 1990s,[49] California's regulatory structure is a hybrid. California has an active wholesale power market with unbundled-generation-competitive wholesale suppliers, but retains retail regulation of the state's three IOUs and does not allow competitive retail service for residential customers.

California passed net-metering legislation in 1996 to apply to all utilities except for Los Angeles Department of Water & Power (LADWP). Subsequent amendments have expanded the regulation to cover more fuel types (e.g., biogas, fuel cells).[50] Under the current net-metering regulations, electrical corporations with more than 100,000 service connections must offer net metering up to a specified program limit or until July 1, 2017, after which "the utility must offer a standard contract or tariff."[51]

Customers receive the bundled retail rate for net excess generation. Before 2009, any annual net-excess-generation credits would revert to the utility. Since 2009, customers have had an option either to roll over credits perpetually or to receive payment at the "surplus compensation rate," which the CPUC defined as the average annual spot price between 7 a.m. and 5 p.m. for the year in which the excess power was generated.[52]

California's net-metering regulations are distinctive among the states in how explicitly they rule out imposing other charges on net-metered customers:

> California does not allow any new or additional demand charges, standby charges, customer charges, minimum monthly charges, interconnection charges, or other charges that would increase an eligible customer-generator's costs beyond those of other customers in the rate class to which the eligible customer-generator would otherwise be assigned. The CPUC has explicitly ruled that technologies eligible for net metering (up to 1 MW) are exempt from interconnection application fees, as well as from initial and supplemental interconnection review fees.[53]

California also has implemented a wide variety of policies beyond net metering to encourage small-scale residential distributed generation. One homeowner-focused rebate program started in 2007, the California Solar Initiative, achieved its goals and exhausted its budget by 2013, having spent at least $1.68 billion to provide an average rebate of $1.40 per watt of capacity on more than 1.2 GW of installed solar PV.[54] This friendly investment climate has encouraged high penetration of PV solar, with a particularly large increase in capacity between 2012 and 2013.

46. Kari Lydersen, "In Wisconsin, Solar 'New Math' Could Equal Big Impacts," *Midwest Energy News*, Jan. 16 2015. Available at http://midwestenergynews.com/2015/01/16/in-wisconsin-solar-new-math-could-equal-big-impacts/. Accessed Aug. 26, 2015.

47. Julia Pyper, "Wisconsin Regulators Vote to Raise Fixed Charges, Add Solar Fees," *Greentech Solar*, Nov. 18, 2014. Available at https://www.greentechmedia.com/articles/read/wisconsin-regulators-vote-to-raise-fixed-charges-and-add-solar-fees. Accessed Aug. 19, 2015.

48. Jeffrey Tomich, "Battles Over Fixed Charges Proliferate in Midwest in Wake of Wisconsin Changes," *Climate Wire*, E&E Publishing, June 15, 2015. Available at http://www.eenews.net/stories/1060020220. Accessed Aug. 26, 2015.

49. Adrian Moore and Lynne Kiesling, "Powering Up California: Policy Alternatives for the California Energy Crisis," Policy Study 280, Reason Public Policy Institute, February 2001.

50. Steven Weissman and Nathaniel Johnson, "The Statewide Benefits of Net-Metering in California & the Consequences of Changes to the Program," Center for Law, Energy & the Environment, University of California, Berkeley, 2012. Available at https://www.law.berkeley.edu/wp-content/uploads/2015/06/The_Statewide_Benefits_of_Net-Metering_in_CA_Weissman_and_Johnson3.pdf. Accessed Sept. 4, 2015.

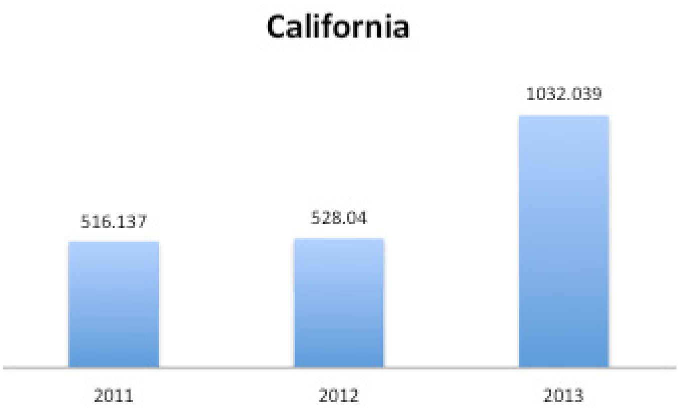
51. Database of State Initiatives for Renewable Energy (DSIRE), "State Net Metering Profile: California," Available at http://programs.dsireusa.org/system/program/detail/276. Accessed Aug. 24, 2015.

52. DSIRE-CA, 2015.

53. DSIRE-CA, 2015.

54. Severin Borenstein, "The California Solar Initiative is ending. What has it left behind?" Available at https://energyathaas.wordpress.com/2013/06/17/the-california-solar-initiative-is-ending-what-has-it-left-behind/. Accessed Aug. 24, 2015.

FIGURE 4: INSTALLED RESIDENTIAL SOLAR PV CAPACITY IN CALIFORNIA, MW, 2011-2013



Source: EIA Form EIA-826

By 2013, the jump in residential solar brought increasing concerns about cost-shifting. With existing net-metering regulations set to expire in 2014, the state Legislature started exploring legislation that would address small-scale distributed energy issues. Naturally, industry and interest groups weighed in to influence the direction of that legislation. PG&E, the investor-owned utility with the largest share of California's net-metered solar, expressed concerns about net metering's consequences for other electricity customers. PG&E Service Analysis Director David Rubin stated: "We are concerned about the upward pressure on rates that could leave customers already struggling to pay their bills worse off."[55]

A.B. 327, which extended the existing net-metering regulations, was signed into law by Gov. Jerry Brown in October 2013. A.B. 327 has three general provisions for the CPUC to pursue in its policymaking:

1. Transforming the 5 percent net-metering program limit, which was due to expire at year-end 2014, into a cumulative MW program-capacity limit for each of the three IOUs.
2. Creating a new "Net Metering 2.0" regulatory proceeding to establish rules, rates and tariffs for DER interconnection and net-metering pricing after those limits are reached or after July 1, 2017, whichever comes first.
3. Determining a transition process to the new regulatory regime for net-metering customers who enroll in the program under the existing rules.[56]

The legislation allows a $10 per month maximum fixed charge. Solar advocates argued this charge would make residential solar unattractive to more customers, while utilities argued that a fixed charge would better align costs across customers and reduce cross-subsidies.[57] The law also, over time, moves the default tariff to time of use (TOU), which means customers will pay more and receive more for energy generated when it is most valuable.[58] The undecided issue that will remain the focus of net-metering regulation for the foreseeable future is fixed charges.

Fully deregulated: Texas

Texas is the only state that has implemented full wholesale and retail market deregulation, without substantial entry barriers to retail markets from incumbent market power. Its regulated wire companies are transmission and distribution utilities (TDUs) that are precluded by law from owning generation or providing retail-energy services. Texas limited the ability of incumbents to lower retail prices and erect entry barriers and also did not implement incumbent default service as a transition path for retail customers, but instead issued procurement contracts for default service.[59] Retail suppliers wishing to enter the retail markets faced lower entry barriers and less exercise of incumbent vertical market power in Texas than in the other restructured states.[60] The most recent Annual Baseline Assessment of Choice in Canada and the U.S. report[61] ranks Texas as the most successful state in implementing retail competition, a status Texas has held for the past eight annual reports.

Texas has no net-metering requirement. Some municipal utilities have residential solar programs; San Antonio has a net-metering program and Austin Energy offers a value of solar tariff, which will be described briefly in Section IV. TDUs have regulated tariffs for distribution and grid

55. Herman Trabish, "Solar's Net Metering Fight in California Previews at Intersolar," Greentech Media, July 11, 2013. Available at https://www.greentechmedia.com/articles/read/Solars-Net-Metering-Fight-in-California-Previews-at-Intersolar. Accessed Aug. 24, 2015.

56. CALSEIA, "Fact Sheet on California's Newest Net Energy Metering Law — AB 327," Oct. 14, 2013. Available at http://www.calseia.org/ab327. Accessed Aug. 23, 2015.

57. Jeff St. John, "AB 327: The Dark Side for California Solar," Greenwich Media, available at https://www.greentechmedia.com/articles/read/ab-327-the-dark-side-for-california-solar. Accessed Aug. 24, 2015.

58. Herman Trabish, "Inside California's Rate Restructuring Plan and the Battle for Fixed Charges Looming over it," *Utility Dive*, July 13, 2015. Available at http://www.utilitydive.com/news/inside-californias-rate-restructuring-plan-and-the-battle-for-fixed-charge/402117/. Accessed Aug. 24, 2015.

59. Lynne Kiesling, "Retail Restructuring and Market Design in Texas," in Lynne Kiesling and Andrew Kleit, editors, *Electricity Restructuring: The Texas Story*, Washington, D.C.: AEI Press.

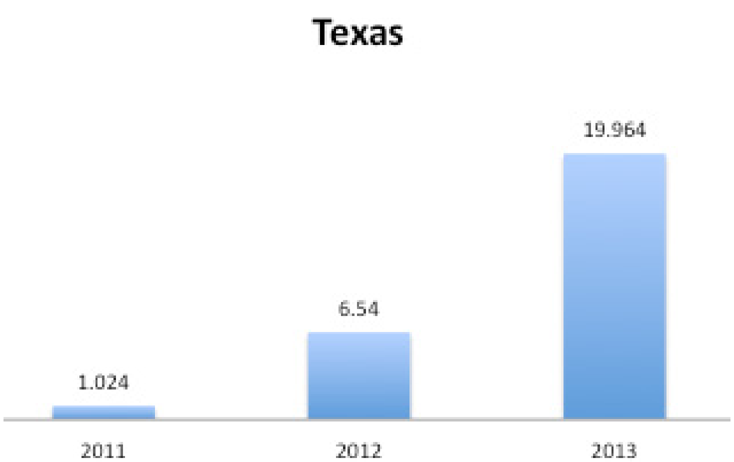
60. Lynne Kiesling, "Incumbent Vertical Market Power, Experimentation, and Institutional Design in the Deregulating Electricity Industry," *Independent Review* 19(2): 239-264.

61. Nat Treadway, "Annual Baseline Assessment of Choice in Canada and the United States," Distributed Energy Financial Group, available at http://defgllc.com/publication/abaccus-2015-annual-baseline-assessment-of-choice-in-canada-and-the-united-states/. Accessed Aug. 11, 2015.

services[62] and a standard distributed generation interconnection agreement.[63]

Under the state's deregulation legislation, energy retailers in Texas are generally free to develop new products and services, including varieties of contracts with customer-generators for DERs.[64] Customers intending to install DERs and interconnect them with the distribution grid are required to file an interconnection agreement with their TDU. The TDU then installs a bi-directional meter; the law requires separate metering of inflows and outflows of energy. The solar buy-back contracts are with independent retailers, not with the wire utilities. Customer-generators pay a regulated wires-and-grid-services charge. However, the regulated tariff does not stipulate clearly whether the customer-generator pays the wires charges associated with energy transportation and grid services stemming from the outflow of energy.[65] Thus, decisions about what price to pay customer-generators is left up to the retailer. Because rates are established on a product basis and not through a regulated rate-setting procedure, no controversies arise over grid services cost-shifting.

FIGURE 5: INSTALLED RESIDENTIAL SOLAR PV CAPACITY IN TEXAS, MW, 2011-2013



Source: EIA Form EIA-826

62. Public Utility Commission of Texas, Electric Substantive Rules, §25.213, Metering for Distributed Renewable Generation and Certain Qualifying Facilities, available at http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.213/25.213.pdf. Accessed Sept. 1, 2015.

63. Public Utility Commission of Texas, Electric Substantive Rules, §25.211, Interconnection of On-Site Distributed Generation (DG), available at http://www.powertochoose.org/Content/Files/PDF/25.211.pdf0_Cw.pdf. Accessed Sept. 1, 2015.

64. Nat Treadway, "Distributed Generation Drives Competitive Energy Services in Texas," in Lynne Kiesling and Andrew Kleit, editors, *Electricity Restructuring: The Texas Story*, Washington, D.C.: AEI Press, 2009.

65. PUCT 2015, §25.213.

Before 2013, Texas had seen small solar growth compared to other states. Much of the solar capacity that has been installed is utility-scale.[66] In July 2015, the solar-energy company Solar City partnered with the Texas retailer MP2 to enter the Texas residential market with third-party solar installations and leasing options.[67]

IV. BEYOND REGULATED RATE-SETTING

States have developed a number of approaches to accommodate DER, with varying degrees of concern for the cross-subsidies inherent in regulated rate-setting. Compensation at the retail rate, energy-only payments or fixed charges for DER customers all face the same inherent problem: the regulated model is out-of-date during a time of major technological changes, shifting policy priorities and increasing heterogeneity among utility customers.

One lesson from the Texas model is that, even if policymakers want to increase proliferation of DERs for any number of objectives, mandates and payment schemes tied to the regulatory model are not necessary. A necessary condition for sustainable value-creating DER growth is an institutional framework that makes the benefits and costs of DERs transparent and transactive. The goal ought to be open retail market in which customer-generators can participate as both buyers and sellers, with the distribution utility operating as the wires and market platform, facilitating market exchange while enabling reliable service in a resilient distribution network.

Open retail market

An open retail market with low entry barriers would create more accurate price signals for distributed energy than existing net-metering regulations. Such decentralized markets are more feasible today than ever before, due to digital innovations and their application in creating new smart-grid technologies. Computerized market-platform software is ubiquitous in daily life and used as the foundation for a range of business platforms, from sophisticated financial markets to eBay and Uber.

Automated distribution and automated digital sensors make decentralized physical coordination and balance possible in ways it was not with mechanical technologies, complementing the ability of decentralized market platforms to make decentralized economic coordination possible and beneficial. Digital meters already enable two-way

66. Bentham Paulos, "Can the Texas Solar Market Live Up to Its Potential?" Greentech Media, May 12, 2014. Available at https://www.greentechmedia.com/articles/read/that-mean-old-texas-sun. Accessed Aug. 24, 2015.

67. James Osborne, "Solar City Pushes Into Texas," Dallas Morning News, March 10, 2015. Available at http://www.dallasnews.com/business/energy/20150310-solar-city-pushes-into-texas.ece. Accessed Aug. 24, 2015.

data communication to accompany bi-directional energy flows. Digital home-energy-management hardware and apps enable automation in response to price signals. Bids and offers change automatically in real time, depending on the status of the DER, the market's available alternatives and the availability of storage.

Retail competition – that is, unbundling the retail function and transaction from the vertically integrated distribution utility – would reduce entry barriers to DERs and promote their organic, resilient growth. The burgeoning residential solar market in Texas – with full retail competition despite the absence of regulatory mandates – provides a starting point on which to build. DERs and digital technologies have been powerful decentralizing forces. As these technologies proliferate and more of them become commercially viable, we are likely to see a second wave of unbundling of the distribution utility.

The unbundling of generation in the 1990s arose from the scale-changing effects of the combined-cycle gas turbine on the economics of generation. Digital and DER technologies will produce similar business-model and regulatory changes. Retail markets with low entry barriers provide a resilient means to enable that transition, because decentralized market processes aggregate diffuse private knowledge (as discussed in Section III) and provide feedback effects through changing price signals that influence investment choices and innovation decisions.

Updated utility business model

Under a platform-business model, a distribution company would provide grid services and operate a retail market open to any number of users. Applying that platform model to electricity distribution suggests some clear roles and scope – electricity distribution and retail-market platform – while still leaving some questions open for analysis and debate.

The defining feature of a platform firm is that it acts as an intermediary connecting two or more agents for mutual benefit. The most common economic role of a platform firm is intermediation in transactions by providing a market platform that brings together potential buyers and sellers, making it easier for them to find each other. Consider the analogy to financial-market exchanges, such as stock exchanges or futures exchanges, which provide trading platforms. By being attentive to the interests of both buyers and sellers, they define standard products and rules by which exchanges will occur; provide timely information and a way for buyers to bid and sellers to offer; and they open or close new markets as the interests of buyers and sellers wax and wane. The distribution-platform firm would be, in large part, a market platform.

In a framework with low entry barriers for both wholesale and retail energy markets, the role and scope of the distribution utility would be as a provider of wires, not energy; grid services, not commodities; a market facilitator, not a participant. The distribution utility would provide distribution and grid services in return for a service fee or wires charge. Such decentralized markets for energy and for grid services would send price signals that create dynamic incentives for investment and innovation in new technologies. Those technologies – such as storage and other technologies that are at this point unknown – in turn enable customer-generators and the distribution platform company both to benefit. States with restructured and/or decoupled rates have already moved in this direction, as seen in the Texas case study.

What will these grid services be? Start with a thin model of a distribution-platform company. Its core functions, responsibilities and transactions will be to coordinate reliable distribution and open interconnection. Rules for interconnection and market participation will be transparent and will apply universally to the distribution-platform company and all others. Open, interoperable technical standards at the distribution edge are the technical requirements that enable transparency. The distribution-platform company will monitor physical flows and balance the system to meet its reliability requirements. It also will operate automated, transactive markets for energy and, eventually, for grid services, enabled by the data flow via the communication platform. The distribution company facilitates this coordination by physical delivery, using the distribution-wires platform.

The other component of a future decentralized-market platform is standard interconnection with an open architecture; interoperability at the edge of the network; and transparent, agreed-upon technical standards for interconnection. The essential key to all of these charges is that the algorithms for calculating them be transparent, consistent and communicated and applied consistently and clearly to all market participants.

As end-users become more heterogeneous and can possess more diverse technologies, the distribution company would create additional value by facilitating the interconnection of those agents and their technologies to the network. In that sense, a distribution platform would layer market platforms on top of the physical-distribution network. The existence of these retail market platforms would generate incentives and opportunities for entrepreneurs to develop devices that can operate on the platform (e.g., vehicles, home-energy management) and applications that connect the owners of those devices to other agents via the platform. By offering interconnection, grid service, and market services that customers value, the distribution utility would earn service fees.

This value proposition is precisely the same as that seen in other platform companies. Ridesharing platforms like Uber and Lyft give vehicle owners an opportunity to monetize an underutilized asset they own – seat space in their cars – while giving others an opportunity to get rides. Ridesharing platforms change the vehicle-purchase calculus at the margin. This affects the decision of when to buy a new car, how nice a new car to buy and how many hours to spend on the platform available to give rides.

Agents operating around the edges of the platform, including independent retailers who are energy-service providers, do everything else. The technologies enable them to offer energy services that are as customized or as generic as consumers prefer, as automated or manual as they prefer, bundled with other services or not as they prefer. As the Texas market shows, those independent retailers also will provide contracts for customer-generators to sell excess generation. In short, it would look like net metering under a deregulated scenario.

Designing market rules and regulatory institutions also requires attention to traditional rate-design principles[68] and consideration of competition policy to limit the extent of the distribution-platform company's participation in the energy and grid-services markets. Having a regulated incumbent distribution company be a market-platform provider and either a buyer and/or a seller encourages the exercise of incumbent vertical market power in the downstream energy and grid-services markets. This is likely to have anti-competitive effects in those markets and reduce the experimentation that is the process by which markets create value.[69]

The burgeoning residential solar market is an example of the kind of market that can grow at the distribution edge.[70] The market has grown substantially over the past decade, through a combination of technology, market and policy drivers, including net-metering regulations. The general trends in the United States and the case studies analyzed in this section show how the residential solar market can be competitive. Its growth would be facilitated by its technological and economic location at the edge of a distribution network with transparent, autonomous interconnection and with competitive retail electricity markets with low entry barriers.

Retail markets for energy and grid services still face the technological challenge of the dispatchability of DERs. The combination of DER intermittency and expensive storage means that algorithms that could automate the dispatch of DERs for energy or for grid services are not yet feasible.

68. Linvill, et al., 2013.

69. Kiesling 2014.

70. Kiesling and Silberg 2016.

But they will be, and designing market rules and regulatory institutions that can adapt as those technologies evolve will provide strong market-investment signals and reduce barriers to experimentation and innovation of new products and services.

Grid-services rate design in a decentralized network

The increasingly costly and contentious net-metering debates in Arizona, California, Nevada and Wisconsin illustrate the problems, as residential solar PV penetration increases, of traditional rate design and cross-subsidization involved in net-metering regulation. By contrast, Texas has avoided such controversies and is starting to see substantial growth in its deregulated residential solar market.

Alternative minimum bill proposals[71] would impose fixed charges on all residential customers, regardless how much electricity they consume. This option would enable distribution utilities to recover fixed costs through fixed charges. To the extent that the minimum bill enables a revision of both the fixed and variable portions of the regulated rate so they align more closely with fixed and variable costs, this unbundling could allow utilities to recover distribution costs while also sending more accurate marginal cost price signals (although, as a regulated rate, it is still only an averaged and thus not a precise price signal). However, such rate designs face the challenge of distinguishing between the fixed and variable portions of grid services that customer-generators use.

Many states are considering revising net metering altogether and instead compensating customers with a value-of-solar tariff (VOST). The VOST takes into account all the costs and benefits of grid-tied distributed-energy resources, including contributions to fixed costs, avoided capital expenditures, environmental externalities and others. A VOST dissociates the excess generation payment to customer-generators from the retail rate.[72]

Austin Energy (AE) in Texas has an active VOST for residential customers. The VOST establishes their payment based on AE's estimate of the average value of the energy sold back.[73] This arrangement reduces dissention and controversy about cost-shifting among heterogeneous residential customers.

71. Jim Lazar, "Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs." Regulatory Assistance Project, November 2014.

72. Mike Taylor, Joyce McLaren, Karlynn Cory, Ted Davidovich, John Sterling and Miriam Makhyoun, "Value of Solar: Program Design and Implementation Considerations," Technical Report NREL/TP-6A20-62361, National Renewable Energy Laboratory, March 2015; See also, Linvill, et al., 2013, p. 44.

73. Herman Trabish, "Can a ''Value of Solar Tariff Replace Net Energy Metering?" Greentech Media, Aug. 24, 2012. Available at https://www.greentechmedia.com/articles/read/can-a-value-of-solar-tariff-replace-net-energy-metering. Accessed Sept. 1, 2015.

Minnesota also has implemented voluntary VOST pricing for DERs; in this vertically integrated state, utilities must choose between the existing net-metering regulation and the VOST.

While both a minimum bill and a VOST offer some attractive features when compared to net metering, neither one truly takes advantage of the powerful decentralizing and automating potential of digital technologies and their reductions in transaction costs. The design of a single, fixed price paid to customer-generators illustrates one of the costs of using a VOST that is similar to the cost of net metering. Administratively determined VOSTs – based on utility-value estimates and incorporating substantially the utility's avoided costs – remains an administered regulatory program that relies too heavily on utility cost as a proxy for DER value. Similarly, a minimum bill may be well-suited to enable utilities to recover fixed and variable distribution and grid-services costs, but not to create and communicate a price signal for DERs and for grid services that enables decentralized agents to determine how much of each they want to produce and consume.

Traditional rate design categorizes costs as variable or fixed and allocates fixed costs across customers when determining a bundled per-kWh retail rate. In a decentralized grid with DERs, this approach does not fully capture grid-services costs and benefits created by DERs. That's because these actually are variable, but usually treated as an allocated fixed cost (while the benefits are generally overlooked). Linvill, et al., provided a thorough analysis[74] of DER-compatible rate design grounded in general principles; their recommendations for regulators are a good complement to the analysis in this paper.

An incremental regulatory approach would be to revise the retail rate to have three components:

1. Energy charge: a per-kWh charge for energy consumed;
2. Grid services charge (variable demand): a per-kWh charge for grid services; and
3. Fixed infrastructure charge: a per-kW charge for a portion of the fixed cost of building and maintaining distribution grid capacity.

When purchasing from the utility, the customer-generator pays this price. When selling excess generation, the customer-generator receives the energy price, plus an estimate of the grid services benefits and the fixed-cost reduction associated with their DER. Such an incremental approach is more similar to the VOST than to either existing net metering or to a minimum bill.

Capital investment remains necessary to bring distribution-platform companies into existence. The biggest architectural challenge is that the distribution grid was not designed for bi-directional energy flows. These investments would be incremental and piecemeal; much of the distribution grid infrastructure that is close to full depreciation and needs to be replaced anyway could, and should, be replaced with smart-grid technologies and bi-directional architecture. This would enable the physical flows that make possible the kinds of economic transaction flows that only a decentralized market platform can offer.

V. CONCLUSION

The problems of net-metering regulation are problems of rate design. Technological change unwinds the allocations of common costs across different groups of customers. In this case, technological change is making residential customers more heterogeneous, so the existing cost allocation is creating cross-subsidies across residential customers. Controversies over net-metering regulation and whether or not customers are paying for the grid services they consume are the logical consequence of this mismatch. Net metering's current controversies arise from the interaction of technological change and changing policy priorities with traditional rate design. Technological change lays bare the cross-subsidies inherent in traditional utility regulation. The fully bundled retail rate makes costs and cross-subsidies opaque, and does not permit clear price signals to the customer, either for energy or for grid services at the margin.

Standard, traditional ratemaking cannot accommodate the increase in customer heterogeneity within the residential-customer class, nor does it exploit smart grid's transaction-cost reductions to enable more decentralized coordination in retail markets on the distribution network. A single regulated net-metering rate is likely only to be accurate on average, because it will not vary with system conditions and does not capture the circumstances of time and place. At best, this regulated net-metering price, even with a demand charge and a fixed charge, is a static proxy for an opportunity cost that is likely to change frequently and sometimes quickly. Today's electricity environment is more heterogeneous and dynamic than the traditional regulatory framework can accommodate.

Those two conclusions lead to an institutional design recommendation: the distribution company should be a platform company with an open retail market platform, open interconnection standards and a transparent two-part grid services charge. This regulatory framework and business model would enable the emergence of clearer price signals that would induce resilient and sustainable investments in DERs and networks that increase their value.

74. Linvill, et al., 2013, pp. 50-51.

APPENDIX: ECONOMETRIC ANALYSIS OF STATE LEVEL TRENDS

Observed dramatic growth in residential solar systems has not been evenly distributed between the states. Recent detailed data from the Energy Information Administration Form 826 provides annual 2011-2013 state-level data on residential solar PV activity. Figure 1 shows the residential solar PV capacity installed by year in Arizona, California and the other states combined; this figure indicates the extent to which residential solar trends are dominated by activity in Arizona and California.

Combining those data with policy variables coded from the DSIRE database of state renewable policies yields some insights into the effect of net-metering policies on individual choices to install solar PV. The hypotheses in question are:

1. Retail price: Other things equal, states with higher residential retail prices are likely to have more residential solar PV capacity because, at the margin, those homeowners are more likely to substitute out of utility-supplied energy than homeowners paying relatively lower prices; and
2. Net-metering price: Other things equal, states with a net-metering rate set equal to the bundled retail rate are likely to have more residential solar PV capacity, because that rate compensates them for more than the energy cost that they would incur if they did not install solar PV.

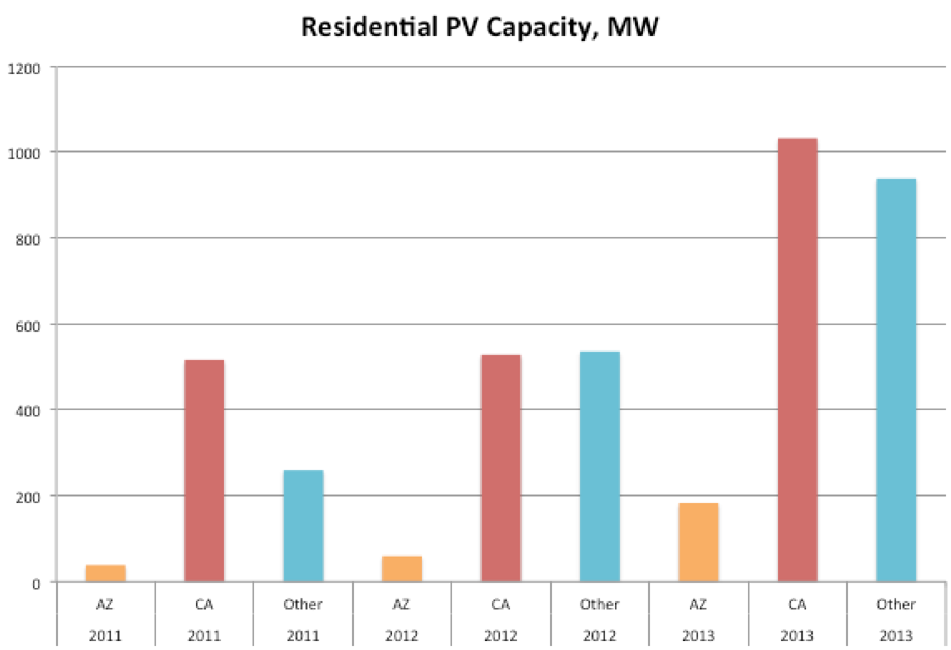
Table 2 provides definitions of the variables used and their sources and Table 3 provides details on the DSIRE database sources for the policy variables.

To test these hypotheses using state-level data for three years 2011-2013, I estimated variations of this model:

$$\text{PV capacity}_{it} = \alpha + \beta_1\text{Retail pricei} + \beta_2\text{NMretail}_i + \text{control variables}_{it} + \varepsilon_{it}$$

Where i represents the state of the observation and t represents the year. Control variables include state GDP; weather variables (the variation in cooling-degree days and heating-degree days from their historical averages); and policy variables (whether the net-metering credits expire and whether the state has residential retail competition). Not surprisingly, activity in California and Arizona is significantly higher than in other states, so some specifications of the model include additional control variables to indicate Arizona and California observations specifically. One specification also excludes California to focus on trends in the other states.

FIGURE 6: RESIDENTIAL SOLAR PV CAPACITY, 2011-2013



Source: EIA Form EIA-826

TABLE 2: VARIABLE DEFINITIONS AND SOURCES

Variable name	Definition
Resid PV capacity	Residential installed solar PV capacity in the state in megawatts (MW)
Avg retail price	Average retail price, residential, total electric industry, cents per kilowatt-hour (kWh)
NM price retail rate	1 if residential customer receives bundled retail price for excess energy, 0 if otherwise
Credits expire	0 if excess energy credits expire or have limited rollover, 1 if not
Retail competition	1 if restructured state with residential retail competition, 0 otherwise
State GDP	Real GDP by state, chained 2009 dollars, dated Jan. 1 of following year
Cooling degree day var	Annual average cooling degree day variation from historical trend
Heating degree day var	Annual average heating degree day variation from historical trend
AZ indicator	1 if state=Arizona, 0 otherwise
CA indicator	1 if state=California, 0 otherwise
Variable name	**Source**
Resid PV capacity	EIA Form EIA-826 http://www.eia.gov/electricity/data/eia826/
Avg retail price	EIA Electric Power Annual http://www.eia.gov/electricity/annual/
NM price retail rate	DSIRE database (see Appendix)
Credits expire	DSIRE database (see Appendix)
Retail competition	EIA Status of Electricity Restructuring by State http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html
State GDP	FRED database https://research.stlouisfed.org/fred2/release?rid=140
Cooling degree day var	EIA Annual Energy Review http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0108
Heating degree day var	EIA Annual Energy Review http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0107

TABLE 3: DSIRE SOURCES FOR POLICY VARIABLES

AK	http://programs.dsireusa.org/system/program/detail/3734
AL	Does not have a net-metering program
AR	http://programs.dsireusa.org/system/program/detail/536
AZ	http://programs.dsireusa.org/system/program/detail/3093
CA	http://programs.dsireusa.org/system/program/detail/276
CO	http://programs.dsireusa.org/system/program/detail/271
CT	http://programs.dsireusa.org/system/program/detail/277
DC	http://programs.dsireusa.org/system/program/detail/105
DE	http://programs.dsireusa.org/system/program/detail/43
FL	http://programs.dsireusa.org/system/program/detail/2880
GA	http://programs.dsireusa.org/system/program/detail/574
HI	http://programs.dsireusa.org/system/program/detail/596
IA	http://programs.dsireusa.org/system/program/detail/488
ID	http://programs.dsireusa.org/system/program/detail/279
IL	http://programs.dsireusa.org/system/program/detail/2700
IN	http://programs.dsireusa.org/system/program/detail/342
KS	http://programs.dsireusa.org/system/program/detail/3403
KY	http://programs.dsireusa.org/system/program/detail/1081
LA	http://programs.dsireusa.org/system/program/detail/983
MA	http://programs.dsireusa.org/system/program/detail/281
MD	http://programs.dsireusa.org/system/program/detail/363
ME	Does not have a net-metering program
MI	http://programs.dsireusa.org/system/program/detail/5773
MN	http://programs.dsireusa.org/system/program/detail/282
MO	http://programs.dsireusa.org/system/program/detail/2621
MS	Does not have a net-metering program
MT	http://programs.dsireusa.org/system/program/detail/37
NC	http://programs.dsireusa.org/system/program/detail/1246
ND	http://programs.dsireusa.org/system/program/detail/285
NE	http://programs.dsireusa.org/system/program/detail/3386
NH	http://programs.dsireusa.org/system/program/detail/283
NJ	http://programs.dsireusa.org/system/program/detail/38
NM	http://programs.dsireusa.org/system/program/detail/284
NV	http://programs.dsireusa.org/system/program/detail/372
NY	http://programs.dsireusa.org/system/program/detail/453
OH	http://programs.dsireusa.org/system/program/detail/36
OK	http://programs.dsireusa.org/system/program/detail/286
OR	http://programs.dsireusa.org/system/program/detail/39
PA	http://programs.dsireusa.org/system/program/detail/65
RI	http://programs.dsireusa.org/system/program/detail/287
SC	http://programs.dsireusa.org/system/program/detail/3041
SD	Does not have a net-metering program
TN	Does not have a net-metering program
TX	http://programs.dsireusa.org/system/program/detail/5545
UT	http://programs.dsireusa.org/system/program/detail/743
VA	http://programs.dsireusa.org/system/program/detail/40
VT	http://programs.dsireusa.org/system/program/detail/41
WA	http://programs.dsireusa.org/system/program/detail/42
WI	http://programs.dsireusa.org/system/program/detail/235
WV	http://programs.dsireusa.org/system/program/detail/2380
WY	http://programs.dsireusa.org/system/program/detail/553

Table 4 reports the results of the estimations of the model in Equation 1, estimated using ordinary least squares with robust standard errors. I tested three specifications of the model: a benchmark including all states and all control variables; a version that excludes the nine California observations; and a version that includes indicator (0,1) variables for Arizona and California. That specification allows identification of whether the hypotheses hold when taking account other state-specific factors in Arizona and California that are not observable in the data.

TABLE 4: THE EFFECT OF RESIDENTIAL RETAIL PRICE AND NET-METERING PRICE ON RESIDENTIAL SOLAR PV INSTALLED CAPACITY

Dependent variable: Resid PV capacity	1	2	3
Independent variables:			
Avg retail price	13.029** [5.485]	3.050** [1.169]	3.970** [1.415]
NM price retail rate	25.151** [11.154]	12.283** [3.899]	8.986** [3.486]
Credits expire	-15.579 [12.351]	-0.806 [5.630]	3.904 [3.603]
Retail competition	-91.173 [35.466]	0.493 [6.624]	2.555 [5.953]
State GDP	0.0002** [0.00006]	0.00001** [0.000007]	8.69E-06 [8.50E-06]
Cooling degree day var	-0.004 [0.063]	-0.005 [0.018]	0.017 [0.027]
Heating degree day var	0.004 [0.017]	0.003 [0.006]	0.011 [0.009]
AZ indicator			84.697** [36.937]
CA indicator			651.054** [144.507]
Excludes CA	N	Y	N
Constant	-167.200 [70.395]	-32.476 [14.119]	
No. of obs.	126	123	126
R-squared	0.5336	0.1538	0.8550

In all three specifications, the results support the two hypotheses. Also across all three specifications, the policy-control variables (net-metering credit expiration and retail competition) are not associated with higher residential solar PV capacity. The weather-control variables also are not statistically significantly different from zero. State GDP does have a positive and statistically significant effect, except for the specification that captures the Arizona and California-specific effects separately.

Column 1 shows the hypothesized determinants of residential solar PV capacity in the benchmark specification, including all states. A one-cent/kWh higher average residential retail price is associated with 13.029 additional MW of installed PV at the state level across all states. States where the net-metering price is the bundled retail rate had 25.151 additional MW of installed capacity on average.

Column 2, the estimation that excludes California, shows a similar but smaller effect of the two variables of interest. Note that, by excluding California, the Column 2 estimation has a substantially lower R-squared (0.1538 compared to 0.5336). R-squared indicates the variation in the dependent variable that is explained by variation in the independent variables. Outside of California the explanatory power of this model is substantially lower.

Column 3, which accounts separately for Arizona and California with state-level indicator variables, reinforces that conclusion. In the other states the retail price and the net-metering price were associated with residential solar PV capacity. But the size of the effects of those two states is large. California had an additional 651 MW of installed capacity on average, and Arizona had almost 85 additional MW. Note also that the R-squared shows that the explanatory power of this model is higher (0.855) than the other two.

This analysis supports the argument that California and Arizona are chiefly driving increases in national residential-solar energy generation. Further, whether the net-metering price is set at the bundled retail rate and the level of that retail rate are the two main economic and policy variables influencing residential solar PV capacity decisions.

ABOUT THE AUTHORS

Lynne Kiesling is an associate professor of instruction in economics at Northwestern University and an associate fellow of the R Street Institute. Her research focuses on the effect of regulatory institutions and their incentives on innovation and technological change, particularly in the electric-power industry. She teaches classes in microeconomics, technological change, environmental economics, antitrust and regulation, environmental economics and the history of economic thought. All of these topics and themes inform her research and other writing