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Via electronic filing at https://ftcpublic.commentworks.com/ftc/solarworshop

**RE: Something New Under the Sun: Competition and Consumer Protection Issues in Solar Power (Solar Electricity Project No. P161200)
Post-Workshop Comments of the American Public Power Association**

The American Public Power Association (APPA) respectfully submits these post-workshop comments in response to the Federal Trade Commission's (FTC's) request for comment in the above-referenced project.

APPA was pleased to participate in the FTC's June 22, 2016 Workshop on Competition and Consumer Protection Issues in Solar Power through the participation by Allen Mosher, APPA's Vice President of Policy Analysis. Mr. Mosher participated on the workshop's first panel, which helped set the stage for later discussions by describing "facts on the ground" relating to the emergence of solar energy, particularly rooftop solar, as an increasingly important electricity supply source for the nation.

APPA is a national service organization representing the interests of not-for-profit, publicly owned electric utilities throughout the United States. The public power sector is comprised of approximately 2,000 individual utilities. These 2,000 public power systems provide electricity to customers in every state except Hawaii, provide over 14% of all electrical energy sold to ultimate customers throughout the United States, own over 10% of the total installed generating capacity in the United States, and serve over 48 million people. The vast majority of public power utilities are small distribution utilities located in and operated as departments of cities and towns. Most public power utilities purchase the bulk of their power supply needs at wholesale from larger entities, including investor-owned utilities, regional transmission organizations, federal utilities, independent power producers and municipal joint action agencies.

The largest public power utility is the Los Angeles Department of Water and Power in California, which serves 1.4 million meters. The smallest public power utility is Midvale Irrigation District in Wyoming, with 6 customers.

Public power utilities operate as not-for-profit entities. There are no shareholders to serve, only the community and the customers who are responsible for paying for costs of the services provided. As not-for-profit, community-owned electric systems, public power utilities leverage their low costs of capital to finance long-term investments to build a least-cost, low-risk power supply portfolio. Investment policies are generally conservative, reflecting the view that the community-owned utility must be operated to achieve the community's goals, rather than to take on risks that might maximize profits from the enterprise. Furthermore, public power's reliance on tax-exempt debt means that the financial strengths of the enterprise and the community are assets that increase bond ratings and help to reduce the cost of financing capital investments.

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Sincerely,

s/ Allen Mosher

Before the Federal Trade Commission

Something New Under the Sun: Competition and Consumer Protection Issues in Solar Power	Solar Electricity Project No. P161200

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In these written comments, APPA will supplement its oral remarks and attempt to provide insights to the FTC on competition and consumer protection issues in an evolving electric power industry. Solar photovoltaic (PV) energy is just one of the emerging technologies that are driving change in the electric power industry. We summarize our comments in brief here and elaborate below:

- Competition in some services is critically important to ensure efficient, pro-consumer outcomes in the electric power industry. However, many services in this industry will remain heavily regulated, making it is difficult to predict whether specific policy interventions will yield more competitive outcomes. Unintended consequences are the rule, not the exception. The FTC should be cautious in its regulatory interventions in specific cases, but can provide useful guidance to the industry, legislators and other regulatory bodies on conduct that may raise concerns with the Commission.
- Public utilities and solar distributed generation (DG) providers have different business models and in fact are selling different products and services to end-use consumers. Solar DG firms can take advantage of the utility's obligation to serve by seeking to avoid paying for power supply reliability and common network costs or to shift costs to non-solar customers. In particular, rooftop solar business models predicated upon utility net energy metering (NEM) have the direct effect of shifting costs from rooftop solar customers to other utility customers. Claims that rooftop solar also results in cost savings for the utility as a whole that offset these cost shifts, theoretically leaving non-solar customers no worse off, have not been demonstrated.

- The apparent savings to electricity consumers from rooftop solar are largely wealth transfers resulting from tax policy and regulatory constraints delaying utilities from replacing net energy metering with efficient pricing designs based on utility avoided costs or market prices for energy, time of use rates, and separate recovery of utility transmission and distribution infrastructure costs.
- Changes in regulatory policies to address rooftop solar, particularly with regard to rate design, are under investigation by legislatures and regulators in most states. For example, the National Association of Regulatory Utility Commissioners recently released a draft manual on distributed energy resource compensation for study and comment. The U.S. Department of Energy is supporting substantial research into improvements in electric utility rate design, as well as research into other issues associated with the nation's increased reliance on renewables and distributed energy resources. Public power utilities have been notable early innovators in modernizing their rate designs.
- Rate design improvements and related technology innovations are preconditions to support efficient increased utilization of renewables including rooftop solar. We need to get the prices right first to get to efficient outcomes and meet federal and state policy goals.
- Rooftop solar also needs to be compared with other supply alternatives, including utility-scale solar and wind and distributed community solar, that may have lower total costs to meet public policy objectives and provide reliable and affordable electric power to the public.
- Emerging technological and market changes may radically affect each of the factors described above. These include energy storage, electric vehicles, advanced metering, advanced grid electronics, home energy management networks, microgrids, and other innovations that may lower the total costs to society of electric energy.
- The emergence of solar DG has raised several consumer-protection issues. The FTC has an important educational role, working with the states, utilities and solar DG providers, to ensure that customers are well-informed about the options they face and protected from providers who use deceptive marketing practices or otherwise take advantage of information asymmetries, leading some customers to make uninformed decisions.
- Each of these issues is manageable and solvable. APPA is optimistic that higher levels of distributed energy resources, including but not limited to rooftop solar, will be successfully integrated into distribution networks throughout the United States in coming years, providing benefits to customers and society at large. However, a cautious approach to address the many technical and economic issues that rooftop solar raises for the electric industry will help to minimize unintended consequences.

1. The Goal of Competition Policy Should Be to Protect Competition, Not Competitors, Business Models or Technologies

Competition (and competitive markets) is superior to regulation (and regulated markets) to the extent that competition achieves a resource allocation that better maximizes the social value of aggregate output, net of the costs of providing that output, given the constraints in available resources and technologies. Public policy toward the electric power industry should seek the least-cost combination of resources that meet customers' demands, with due consideration of the environmental benefits of clean resources. Hence, public policy should protect competition that leads to the most efficient resource mix, rather than protect any particular type of competition or competitor. More specifically, public policy for the distributed solar industry should be based on the principle that all competitors be allowed to compete on the basis of their relative efficiencies in providing electric power services that meet customer needs.

The difficulty for the electricity industry is that it faces multiple layers of public policies designed to accomplish often conflicting economic, environmental and social policy goals. This overlay of policy and regulation makes it difficult to ensure competitive outcomes in one sector of the industry that does not have unintended consequences in other areas. Analysts and commentators long ago stopped discussing electricity "deregulation" and instead began speaking of electric restructuring.

In particular, although distributed solar resources like rooftop panels could reduce the need to build new, expensive thermal power plants, that benefit could also be achieved through utility-scale solar and energy efficiency programs, both of which are substantially less expensive alternatives to rooftop solar and likely to remain less expensive despite foreseeable cost reductions in rooftop solar units. According to GTM Research, recent utility-scale solar power purchase agreements have been executed for as low as 3.5 to 5 cents per kWh.[1] A recent Lawrence Berkeley National Lab study reports that prices for wind energy have fallen to around 2 cents per kWh.[2] Under net energy metering, rooftop owners are being compensated based on residential energy rates that averaged 12.52 cents per kWh in 2014.[3]

Furthermore, several studies have shown that residential-scale PV solar does not provide greater external benefits than utility-scale PV solar. On the contrary, residential solar creates greater external costs.[4] Consequently, there appears to be no economic or environmental justification for

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[1] U.S. Solar Market Insight, Executive Summary, Q2 2016, GTM Research for the Solar Energy Industries Association, page 11.

[2] See LBNL News Release at: http://newscenter.lbl.gov/2016/08/17/annual-wind-market-low-wind-energy-prices/ . citing the *2015 Wind Technologies Market Report* at: https://emp.lbl.gov/publications/2015-wind-technologies-market-report

[3] US Energy Information Administration, http://www.eia.gov/electricity/annual/html/epa_01_02.html

[4] B. Tsuchida, S. Sergici, B. Mudge, W. Gorman, P. Fox-Penner, and J. Schoene, *Comparative Generation Costs of Utility Scale and Residential Scale PV in Excel Energy Colorado's Service Area*, July 2015, available at

giving residential solar preferential treatment. Yet many existing public policies combine to both extend such preferences to rooftop solar or to prevent other policy changes to mitigate unintended consequences and ensure broader benefits to consumers.

Moreover, rooftop solar is just the first (and most prominent) of a host of new technologies, business models and evolving customer preferences that are likely to change customer expectations and relationships with electric utilities and third-party service providers. The FTC's forward-looking mission to promote competition and protect consumers should be addressed in this light.

2. Electric Industry Regulation and Market Structure Has Evolved with Technology

Regulation of electric utilities emerged a century ago as an alternative to competition due in part to scale economies in both the production and distribution of electricity by vertically integrated firms. Because of production and distribution economies of scale and scope, the electric utility industry structure quickly evolved around increasingly larger central power stations whose output was carried to customers over monopoly-owned transmission and distribution (T&D) systems. Regulation of utilities emerged in the late 19th and early 20th century initially through municipally-granted franchises intended to promote utility competition, but it was replaced by state regulation after New York and Wisconsin created state commissions. State regulation emerged at least in part because of a prevailing view that utility economies of scale meant one firm could serve a given geographic area more efficiently than multiple firms. Regulation was established to prevent the utility from exercising its monopoly power to raise prices charged to captive customers.

The electric power industry witnessed rapid consolidation as a result of widespread electrification of the country and the economies of scale that accompanied that consolidation. Vertically integrated utilities dominated the industry structure and were accorded exclusive franchise territories under a regulatory obligation to serve all customers at cost-based rates.

The energy crisis of the 1970s, substantial cost overruns in utilities' nuclear and some coal power investments, slowing growth in electricity consumption, and a general political movement toward lighter regulation all contributed to the belief that generation economies of scale had been exhausted and that competition among generation resources in the wholesale market could replace cost-based rate regulation of that industry segment.[5] A key piece of legislation was the Public Utility Regulatory Policies Act of 1978 (PURPA), which fostered competition in

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http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado's_Service_Area.pdf. Lazard, *Lazard's Levelized Cost of Energy Analysis – Version 9.0*, November 2015, available at https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-90/.

[5] *See* Bernard S. Black & Richard J. Pierce, *The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 COLUM. L. REV. 1339, 1344–45 (1993).

electricity generation services by requiring utilities to purchase power from certain non-utility generators at prices no greater that the utilities' avoided costs.

In the 1990s, there were excellent reasons to expect that wholesale competition in U.S. electric power markets would lead to substantial improvements in electric industry performance. In particular, institutional barriers to trade had annually impeded billions of dollars of cost-reducing trades among wholesale power entities. Consequently, these barriers were broken down by the Energy Policy Act of 1992 and, more importantly, by the Federal Energy Regulatory Commission's implementation of unbundled wholesale open access transmission service beginning with Order No. 888 in 1996.[6] The resulting open access transmission service on the interstate grid was soon followed by the creation of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) that consolidated and improved the generation dispatch serving roughly two-thirds of the U.S. population.[7] In addition, wholesale competition has improved generation performance incentives, which has contributed to improvements in generators' availability (capacity factors) and, together with generation technology advances and recently low natural gas prices, reductions in wholesale generation costs.

By contrast, retail electricity competition addressed power industry services for which improvements could only be modest. Since the 1970s, analyses of retail electricity markets have conclusively demonstrated that, in the short run, customers have only limited responses to electricity prices; so customers' participation in short-term electricity markets could lead to only small improvements in the benefits that customers derive from electricity. Curtailable service programs had already demonstrated that customers are often unwilling to have their service curtailed even when they had received advance credits for doing so. Nonetheless, the real social gains from wholesale electricity competition created hopes, in the 1990s, that retail electricity competition might also lead to social gains in the forms of reduced electricity prices and better customer service. On the basis of these hopes, nearly half the states mandated or allowed retail competition starting in the late 1990s and early 2000s. Nonetheless, the available evidence of the past twenty years indicates that retail competition has ambiguous impacts on both retail electricity prices and retail electricity service.

There are a number of similarities between the present drive to accommodate rooftop solar and the reforms of retail markets in the 1990s and 2000s. An important lesson learned from the last round of retail restructuring is that promises of benefits are often grossly inflated to induce policymakers to transform markets and market structure. Borenstein and Bushnell summarize this point as a caution to policymakers confronting the issues raised by DG solar:

> We argue that the greatest political motivation for restructuring was rent shifting, not efficiency improvements, and that this explanation is supported by observed waxing and waning of political enthusiasm for electricity reform. While

[6] *See New York v. FERC*, 535 U.S. 1 (2002) (rejecting challenges to FERC Order No. 888).

[7] For information on RTOs and ISOs see the FERC's website at http://www.ferc.gov/industries/electric/indus-act/rto.asp. Note the ISO in the Electric Reliability Council of Texas (or ERCOT) is subject to oversight by the Public Utility Commission of Texas and not FERC. *See* www.puc.texas.gov and www.ercot.com.

> electricity restructuring has brought significant efficiency improvements in generation, it has generally been viewed as a disappointment because the price-reduction promises made by some advocates were based on politically-unsustainable rent transfers. In reality, the electricity rate changes since restructuring have been driven more by exogenous factors - such as generation technology advances and natural gas price fluctuations - than by the effects of restructuring). We argue that a similar dynamic underpins the current political momentum behind distributed generation (primarily rooftop solar PV) which remains costly from a societal viewpoint, but privately economic due to the rent transfers it enables.[8]

Policymakers today should try to avoid committing the same types of mistakes in dealing with rooftop solar.

Initial signs are that many officials and the public have expectations about the performance and costs of renewable and distributed energy, particularly customer-owned distributed generation, that are at best optimistic. However, with the right technological innovations and a sound business and regulatory foundation, many of these competing objectives can be reconciled.

3. Utilities and Solar DG Retailers Sell Different Products Because of Differences in Obligations to the Customer

Solar DG installed, owned, operated by a third party is, at best, a partial competitor to utility retail electric service. And that reading is a charitable one. The solar DG retailer provides an unbundled energy-only service in variable quantities, only in the daytime, and that does not follow and meet the customer's changing load, in marked contrast to the bundled firm load-following energy, transmission, and distribution services provided by the customer's electric utility. Solar DG retailers do not provide their own backup for solar PV's failure to perform, but instead depend upon utilities for backup and other essential services. In contrast, utilities sell bundled service, provide their own backup and other essential reliability services, and bear almost all performance risk.

Under a solar DG lease or purchased power agreement, the solar DG retailer is under no obligation to serve, in contrast to the utility that has an obligation to provide firm energy service 24 hours a day, 7 days a week. Maintenance obligations and attendant risks are borne entirely by the customer under the solar DG ownership model, and are borne to a lesser degree by the customer even under lease or purchase models. With utility service, the customer bears no risk other than the infrequent risk of distribution system failure, which creates risk under the solar DG models as well.

[8] Severin Borenstein & James Bushnell, *The U.S. Electricity Industry after 20 Years of Restructurin*g, 7 Annu. Rev. Econ. 437 (2015), available at http://www.annualreviews.org/journal/economics.

With solar DG, the consumer is obligated to pay for financing under both the ownership and lease models, though the terms of financing differ. With utility service, the consumer has no financing obligation.

APPA describes these differences in business models and product offering in greater detail below.

4. The Utility Industry and Solar DG Business Models Differ Because of Distinct Differences in Supplier and Customer Obligations.

Utility Business Models

As a result of electric power industry reforms over the past twenty years, two models are currently employed in the U.S. to deliver electric power service to retail consumers.

Vertically integrated utilities provide bundled energy, transmission, and distribution services, as well as ancillary and customer services, to all end-use retail customers within a franchised service territory. Under this model, the energy provided by the utility to its customers may be produced by its own generation or may be procured from others, generally through bilateral wholesale transactions. This model is used by many investor-owned utilities, public power utilities, and rural electric cooperatives.[9] For investor-owned utilities operating within the traditional model, the business model focuses on the returns to shareholders from generation, transmission, and distribution, as well as on ensuring generation capacity adequacy and the reliability of their T&D systems.

In contrast, the ***retail choice market model*** offers retail customers a choice of suppliers of electric energy service, although such energy is still delivered to customers through the monopoly T&D system. Retail choice is usually offered by states in regions of the country that have centralized wholesale generation markets operated by RTOs or ISOs, although some states with the traditional vertically integrated model also are situated in RTO or ISO regions. In retail choice states, many investor-owned utilities have divested their generation assets; such utilities' business models primarily focus on maintaining reliability and ensuring an adequate return to their investors on their T&D wires investments. In some states with retail choice, investor-owned utilities continue to retain ownership of generation assets but have functionally separated those assets from their T&D assets through creation of wholesale generation affiliates. Consequently, their business model is similar to that of utilities in traditional states, with the important difference that the generation affiliate is subject to the risks attendant to the wholesale market.

[9] In addition, many non-vertically integrated public power and cooperative utilities also operate in a vertically integrated mode by using jointly owned generation or transmission facilities. The history of municipal joint action agencies is described in Jeanne LaBella, *The Evolution of Joint Action*, 72 PUB. POWER, Jan. 2014, at 10, *available at:* http://www.publicpower.org/Media/magazine/ArticleDetail.cfm?ItemNumber=39942.

In addition, the retail choice market model involves retail marketers who purchase energy and capacity in wholesale markets to serve retail load. Unlike distribution utilities, retail marketers have contractual rather than regulatory obligations to serve customers: they are free to enter or exit retail markets as they please, subject to their contractual commitments to suppliers and customers; their retail prices are not regulated by state commissions, although most state commissions impose conditions on the terms and condition of services offered by retail marketers. Their business model is focused on the profits earned through the resale of energy at retail and the returns they can provide to their investors.

One critical point must not be lost: in both vertically integrated and retail choice states, retail customers receive bundled, firm, load-following electric service. Competition in the generation and retail marketing stages does not change the bundled electric service received by the end-use customer. While customers may choose to take on certain additional market price risks in retail choice jurisdictions, few customers take on any risk of load curtailment, for example.[10]

Public Power Business Model

Public power utilities, like investor-owned and cooperative utilities in the traditional market model setting, sell full requirements service, including an obligation to reliably serve all customer load from a real-time operations time frame through a long-term planning horizon. Customers have no obligation to pay for more than their actual monthly use, with no long-term ownership or contractual commitment. In essence, residential customers have a free, unpriced option for any future quantity of use that is within the capability of the customer's distribution feeder connection, meter, and breaker box. Furthermore, customers are free to do whatever they want to alter their energy consumption behind the meter. The utility may offer conservation and load management services, but these are optional services.

Public power utilities operate as not-for-profit entities. There are no shareholders to serve, only the community customers who are responsible for paying for costs of the services. If a rate design does not recover the costs incurred to serve a particular customer or class of customers, including the common costs incurred by the utility, then the rates for other customer classes must rise to recover those costs, and therefore will exceed the costs to serve them. Such inter-class cross subsidies promote inefficient consumption and investment decisions by both classes of

[10] There is growing interest in demand response programs to manage transmission system congestion and generation scarcity/shortage conditions in wholesale markets, particularly in the so-called organized markets operated by RTOs. Demand response is typically procured from large industrial and commercial customers that are capable of curtailing some portion of their load requirements, as well as customers that own and operate dispatchable distributed generation that can be used to offset the net load imposed on the bulk power transmission grid by distribution utilities. Similar load curtailment programs are found in vertically integrated areas as well. Under a 2007 congressional directive, FERC issues annual reports that assess electric demand response resources and the saturation and penetration rate of advanced meters. These reports can be found on FERC's website at http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

Demand response has important implications for wholesale market performance, since it could add short run demand elasticity that could moderate wholesale price spikes and make attempts to exercise market power through strategic withholding unprofitable. A full discussion of these concepts is outside of the scope of these comments.

customers. Public power utilities generally seek to minimize these cross-class subsidies in service rates.

As not-for-profit, community-owned electric systems, public power utilities leverage their low costs of capital to finance long-term investments to build a least-cost, low-risk power supply portfolio. Investment policies are generally conservative, reflecting the view that the community-owned utility must be operated to achieve the community's goals, rather than to take on risks that might maximize profits from the enterprise. Furthermore, public power's reliance on tax-exempt debt means that the financial strengths of the enterprise and the community are assets that increase bond ratings and help to reduce the cost of financing capital investments.[11]

Solar DG Industry Business Model

The business model[12] adopted by the solar DG industry differs from that of the electric power industry — the public power business model in particular — because the obligations of solar DG providers typically are limited to sale of the solar unit or the energy from that unit, while utilities must ensure reliable service to meet the customer's needs 24 hours a day, 7 days a week. The solar DG industry business model is profit-oriented, and targeted at residential and commercial customers. In contrast to the public power business model, the solar DG industry business model needs to have no regard for the financial impacts of solar subsidies on non-solar customers, or for the cost impacts of solar DG integration associated with the wires and reliability services provided by the utility.

The solar DG industry is in the business of selling a "generator" to a utility's end-use customer, in contrast to public power's business of selling a bundled product of energy along with all other services that make the energy valuable to that customer. Consequently, the solar DG industry business models are centered around the question of who owns the photovoltaic (PV) unit and

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[11] For a description of public power in the United States, its role in the electric industry, and public power's business model, see the resources on APPA's website at http://www.publicpower.org/about/index.cfm?navItemNumber=37583.

[12] This section relies on a variety of sources including the following: Matasci, Sara. "A Guide to Common Solar Energy Terms." EnergySage, 9 Mar. 2016; Hausman, Nate. A Homeowner's Guide to Solar Financing Leases, Loans, and PPAs. Rep. Clean Energy States Alliance, May 2015; Fardig, Oskari, Carolina Kansikas, and Antti Niemi. Kerrisdale Capital Investment Case Study Competition- Spring 2015 SCTY's Road to Six Feet Under. Rep. Aalto University School of Business, Spring 2015; Hoium, Travis. "Are Solar Leases Actually Bad for Homeowners?" The Motley Fool, 27 June 2014; "Is Solar Leasing Worth It?" Wholesale Solar. Wholesale Solar, n.d. Web. 5 Aug. 2016; Harney, Kenneth. "Leased Solar Panels Can Complicate - or Kill - a Home Sale." Los Angeles Times, 22 Mar. 2015; Wade, Will. "Rooftop Solar Leases Scaring Buyers When Homeowners Sell." Bloomberg.com. Bloomberg, 24 June 2014; Frantzis, L., S. Graham, R. Katofsky, and H. Sawyer. Photovoltaics Business Models. N.p.: National Renewable Energy Laboratory, Feb. 2008. PPT; "Solar Lease Disadvantages." Solar Lease Does It Make Sense for Residential Applications? n.d. Web. 3 Aug. 2016; Solar Purchase Power Agreements Brief Sheet. Issue brief. Arizona State University Energy Policy Innovation Council, n.d. Web. 3 Aug. 2016; Richards, Tori. "Surprised Solar Customers Find Themselves with Liens." Watchdog.org, 15 Apr. 2015; Denning, Liam. "Throwing Light on Value at SolarCity." The Wall Street Journal, 11 May 2014; Freedman, Robert, and Patricia Hammes. US Solar: Of PPA Securitisations, Horizons & Hurdles. Rep. Shearman & Sterling, 11 Nov. 2011.

how the solar DG retailer will profit from the sale or leasing of the unit. The ***PV Sales*** business model, built around sales, installation and financing of PV arrays that are owned by the residential customer, has been around for decades. Studies indicate that ownership gives residential customers the highest financial returns on their rooftop solar participation.[13] But in recent years, the sales model has been superseded by the ***PV Lease*** model under which the solar retailer retains ownership or transfers ownership to other investors. The lease model has become dominant because while it has minimal upfront costs to the residential PV customer, the long term stream of revenues over the lease term is more profitable for the solar DG retailer (and not coincidentally, less beneficial to customers). Consequently, consumer education, discussed further below, is of paramount importance to enable residential customers to make fully informed decisions based on reasonable analyses of the benefits and costs.

The lease model involves ownership by a third party other than the customer or the utility. This third party owns the PV system and then sells the power or use of the system back to the customer at whose site the PV system is installed. The chief advantages of this model over the sales model are that the third-party seller often has access to low-cost financing; greater ability to assume, understand, and mitigate technical risks; and an ability to make use of all government incentives. On the other hand, the lease model enables the third-party owner to engage in rent-seeking and to exploit customers' failures to understand the complexities of contractual arrangements and the consequences of entering such arrangements.

For the lease model, a third-party owner acts as project developer and identifies a customer and a project. At project completion, the third-party becomes the system owner. In this model, the third-party owner raises capital (generally debt) to finance the project, owns the project, and takes advantage of the tax incentives and accelerated depreciation. The third-party owner enters into a lease or power purchase agreement (PPA) with the end-user, typically with five- to twenty-year durations and specified performance guarantees. The third-party can be a stand-alone business (e.g., MMA Renewable Ventures) that contracts out the installation, system supply and all the system maintenance and monitoring (e.g., SunPower and others); or the third-party can take responsibility directly for portions of the integrator, installer, O&M and monitoring businesses (e.g., SunEdison).

The third-party business model has been embraced by the solar DG industry because it promises to be relatively profitable in the long term. SolarCity and SunPower have found that leases add more value for shareholders than selling systems, whose profit margins are generally razor thin. These firms take advantage of various federal and state tax incentives to attract investment that covers the costs of installation. If the financing can be repaid within the first several years of the unit's expected life, there is an opportunity to profit in the latter years. The profitability of this

[13] B. Hoen, R. Wiser, S. Adomatis, T. Jackson, J. Graff-Zivin, M. Thayer, and G.T. Klise, *Selling Into the Sun: Price Premium Analysis of a Multi-State Dataset of Solar Homes*, Lawrence Berkeley National Laboratory, Report #LBNL-6942, January 19, 2015, available at https://emp.lbl.gov/sites/all/files/selling-into-the-sun-jan12.pdf . This study focused solely on homeowner owned PV systems, not on leased or PPA systems. R. Nevin, and G. Watson, "Evidence of Rational Market Valuations for Home Energy Efficiency," *The Appraisal Journal*, October 1998, pp. 401-409, available at: https://pureenergies.com/us/files/2014/07/solar_home_value.pdf. This analysis focused on homeowner owned energy efficiency equipment and appliances.

model relies heavily, however, on assumptions that the customer will fulfill its contractual commitments over twenty years and will renew the lease for at least an additional ten years. Because Americans own their homes for an average of seven years, these assumptions are problematic.

Almost all states, through orders issued by state utility commissions, mandate that rooftop solar owners be paid net metering rates that credit customers not only for the electrical energy services provided by their solar panels, but also for distribution and other services that are *not* provided by their panels.[14] Net metering rates are important to solar DG retailers because they are attractive selling points to prospective residential and commercial customers. In the case of a long-term PPA or lease arrangement where the customer is effectively buying power from the third-party solar DG provider, the sale of any excess energy to the grid at the net metered full retail rate would be retained by the provider (presumably), which significantly limits the loss on the sale of energy to the customer at a rate below the utility rate. According to the Energy Information Administration, the regional levelized cost of energy from PV solar ranges from about 9 cents per kWh to 19 cents per kWh (2013 $), with a midpoint at about 12 cents per kWh,[15] while the regional levelized avoided cost of energy runs from 6.7 cents per kWh to about 9 cents per kWh, suggesting that benefits of rooftop solar (i.e., the avoided costs) are outweighed by the solar PV system costs.[16] To make an attractive offer, the solar DG retailer generally needs a net meter rate above that average to be able to make a claim that the customer will save on its electricity bills. Under current fuel market conditions, an efficient price that is based on the value of the electrical energy produced by solar panels, rather than on a retail rate that includes charges for transmission and distribution services, would almost always fall well below the average cost of residential solar DG, and would therefore undermine the sale and the long-term profitability of the third-party business model concept. Under current power market conditions and PV technology costs, the solar DG industry is heavily dependent upon the large subsidies implicit in net metering as well as federal and state tax subsidies.

5. Solar DG Poses Greater Power System Control Challenges Than Does Conventional Generation.

Solar DG requires significant changes in the ways that distribution systems are designed and operated. Distributed generation — and particularly intermittent resources with output that

[14] State net energy metering policies and recent developments are described in N.C. Clean Energy Technology Center, *50 States of Solar: Q1 2016 Quarterly Report* (April 2016), available at https://nccleantech.ncsu.edu/resource-center-2/fact-sheets-publications.

[15] This range and midpoint are consistent with the average levelized cost of energy for solar PV across all utilities in California of about 15 cents per kWh as reported in California Public Utilities Commission, California Net Energy Metering Ratepayer Impacts Evaluation, Table 3, p. 8, (Oct. 28, 2013), available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/NEMReportwithAppendices.pdf.

[16] See the Energy Information Administration website at: http://www.eia.gov/todayinenergy/detail.cfm?id=21492 .

depends upon fluctuations in weather conditions, like solar — poses challenges for maintaining power balance on electric power distribution systems. These challenges are described below.

Power Balance Challenges

In power systems, supply and demand must be exactly in balance at all moments in time. Power systems therefore have complex systems by which certain resources, particularly generators, change output to meet changes in load and other power system conditions.

Solar DG generally results in the customer imposing an increased demand for additional grid reliability services to manage fluctuations in the output of the distributed resource and to support outages of the distributed resource. Residential PV solar does not make the customer independent of the utility, but instead changes the customer's dependence upon the utility. The customer continues to buy power from the utility when PV output is less than the customer's load, including when the PV system is not producing any power at all, such as at night. Even when the sun is shining, the solar customer is still dependent upon the grid to start certain equipment in the home like air conditioning units which require more current for startup than can be provided by a solar system. The customer depends upon the utility to take its power when the solar PV is producing more than the customer is consuming.

Under net metering, the utility is responsible for "banking" the customer's excess production, ensuring that the customer's PV system works seamlessly with the utility's interconnected grid. From the customer's perspective the utility's grid acts like a convenient and free storage system for customer-generated power. From the utility's perspective, this is magical thinking. Electric energy must be generated at the moment that it is needed. While electricity (or electric energy potential) can be stored, in the form of batteries, compressed air, flywheels or pumped hydro-electric energy, these technologies are generally very high cost compared to current market prices, have very limited energy storage capacities, or are exceedingly difficult and high cost to site and construct. The utility's ramping of its generation up and down or buying and selling energy in the wholesale market to maintain the system balance between load and generation constitutes the provision of ancillary services. Consequently, the utility must maintain sufficient generating and demand-side resources to follow fluctuations in the customer's solar PV output.

Distribution System Challenges

Increasing levels of solar DG penetration can make significant demands on the distribution infrastructure and require significant investments on the part of the utility to accommodate these demands. In particular, distribution systems must be adapted to the two-way flows – to the customers, as is traditional, plus from the customer, which is new – characteristic of DG. In some parts of the country, relatively high levels of DG penetration have already had significant impacts on the distribution utility and its ability to maintain reliability and power quality.

The impacts of behind-the-meter generation are not yet fully integrated into most utility operations and services. Even with advanced metering, the distribution grid was not designed or built for the two-way flow of energy. Depending on the PV penetration level and distribution grid topology (including the sizes and locations of PV), the need for essential reliability services may be increased or decreased on a particular feeder. While it is possible that distributed solar could save on transmission costs, distribution costs will generally go up because of the technical upgrades needed to accommodate two-way power flows. The adaptation of the distribution system cannot occur overnight and for many power systems will take time to convert to accommodate two-way flows. This does not represent a barrier to entry but a technological and engineering problem requiring time for resolution.

Real-World Impacts

When the penetration of rooftop solar is small relative a utility's total system, the impacts of intermittency of are modest. However, when the penetration reaches levels such as those experienced in Hawaii and California, the impacts create real and costly operational problems. Hawaii provides a vivid example of the technical problems that utilities face in integrating DG. As a result of high levels of DG solar penetration, the Hawaiian Electric Companies (HECO) have experienced "reduced system reliability and security due to the technical and operational characteristics"[17] of solar DG. As HECO states, "[t]he impacts result from the variability of [solar] power output, difficulty in forecasting [solar] production, excess [solar] production during daytime periods with limited [solar] production at evening peak, disconnection during system disturbances, issues associated with being connected to the radial distribution system, and lack of visibility and control."[18] HECO points out that the "majority of existing DG… do not have identified mitigation measures to support the system (i.e., do not have fast-trip capability to mitigate transient over-voltage disturbances; or the ride-through settings required to remain connected through system disturbances, or the ability to reduce DG production when it exceeds demand on the system)."[19] HECO points out that "[m]itigation of the economic and technical issues to ensure a sustainable DG program will require a combination of grid capital investments and modifications and changes to interconnection requirements for and capabilities of the DG."[20]

When industrial customers install generation behind the meter, they typically enter a contractual agreement with the utility to provide backup energy and capacity, along with all other essential transmission, distribution, and reliability services. They agree to pay for these services. In contrast, when the net metering rate is set at the full retail rate, as it generally is, the third-party provider of the residential rooftop unit essentially gets transmission, distribution, and reliability services at no cost. Even worse, when a rooftop solar unit generates a surplus, net metering pays

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[17] Before the Public Utilities Commission of Hawaii, "Hawaiian Electric Companies' Motion for Approval of NEM Program Modification and Establishment of Transitional Distributed Generation Program Tariff," *In the Matter of the Public Utilities Commission Instituting a Proceeding to Investigate DG Resource Policies*, Docket No. 2014-0192, January 20, 2015, http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15A20B13419D27829.

[18] *Id.* at 33.

[19] *Id.* at 37.

[20] *Id.* at 33.

the customer for transmission, distribution, and reliability services it does not and cannot provide.

6. Net Metering Policies Distort Investment and Consumption Decisions and Result in Cross-Subsidies from Non-DG Customers to DG Customers.

Most utilities follow a traditional cost-of-service model to set electricity rates, guided by the principles established by Bonbright.[21] Utility rate analysts must forecast utility revenue requirements and allocate costs to each customer class. Traditional rate design meets these allocated revenue requirements through fairly simple methods that assign the lion's share of residential and small commercial customer bills to per-kWh energy charges and small shares of residential bills to a fixed monthly charge. Large commercial and industrial bills tend to recover costs about equally through energy charges and per-kW demand charges.

Energy charges have traditionally been flat per-kWh charges that are the same in all time periods of the year, even though utilities' costs of serving customers vary greatly by time of day and season. Some utilities have introduced seasonal charges, with summer and winter rates set slightly higher than rates at other times of the year. Other utilities implement time-of-use rates that set charges for peak hours higher than those for off-peak hours. Some utilities use more complicated formulas, such as for critical peak pricing, with very high charges for the highest-load hours, slightly lower charges for hours with lower loads, and very low rates for off-peak hours such as the late evening.

The Electric Power Research Institute has found that a typical U.S. residential customer uses 982 kWh of electricity per month, with a bill averaging $110, of which $70 are for generation services, $30 are for distribution services, and $10 are for transmission services.[22] Nearly all the distribution and transmission costs are fixed costs that do not vary with hourly customer loads, while about 80% of generation costs are variable. This means that $54 of the typical residential

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[21] J.C. Bonbright *et al*., *Principles of Public Utility Rates*, 2nd ed. (Arlington, VA: Public Utilities Reports, Inc., 1988). Bonbright's principles are: Provide adequate and stable revenues to the utility. Be stable, predictable, and easy for customers to understand. Reflect fair cost allocation to rate classes. Reflect present and future private and social costs. Discourage wasteful use of service. Avoid undue discrimination in rate relationships (i.e., be subsidy free with no inter-customer burdens). Promote dynamic efficiency and innovation.

[22] Electric Power Research Institute, The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources (Palo Alto, CA: Electric Power Research Institute, 2014), 21-22, available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733.

customer bill[23] is related to fixed costs. Because residential fixed charges are typically around $10 per month, utilities recover most of their fixed costs through variable rates.[24]

Net metering charges customers for the amount by which their monthly electricity consumption exceeds their generation; or it pays customers for their net monthly surplus generation. In other words, the customer's meter runs forward when the customer takes electricity from the grid, and runs backwards when the customer puts surplus electricity from rooftop solar into the grid.[25] If the customer consumed more energy than it generated during a billing period, the customer pays for its net energy (kWh) usage at the usual retail tariff rate. If the customer produced more energy than it consumed during the billing period, the utility credits the consumer for the excess kWh either at the usual retail tariff rate or at a rate dependent upon the market value of electric energy.[26]

Paying the customer for solar generation at the retail tariff rate has the effect of substantially subsidizing customers with solar DG. This occurs because utility tariffs, designed during an era without DG, presumed that retail electrical energy charges were an appropriate vehicle for the recovery of utilities' T&D capacity costs. Because of the design of utility tariffs, net metering allows customers with solar DG to escape responsibility for paying for the distribution facilities that serve them. This is easily recognized for the customer whose solar generation happens to exactly equal its load: such a customer would pay a zero energy charge even though it would export power through the utility's distribution system during the daytime and import power through the utility's distribution system during the nighttime. Under the prevailing retail electricity tariffs, the customer's payment for its use of the distribution system would be limited to a paltry monthly customer charge. In general, the costs of DG customers' use of distribution system are shifted to non-DG customers, a shift that will become larger as more customers install DG systems.[27]

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[23] $54 = 100% * ($30+$10) + 20% * $70.

[24] Other research on the issue finds similar results. For example, see Innovation Electricity Efficiency, *Value of the Grid to DG Customers*, October 2013, available at http://www.edisonfoundation.net/iee/Documents/IEE_ValueofGridtoDGCustomers_Sept2013.pdf.

[25] Many utilities are moving to more complex metering technologies where the output of the solar array is metered separately from the customer's load. This move takes place as part of a general shift by utilities to Advanced Metering Infrastructure. Particularly with AMI, this configuration has the advantage of allowing the utility to disconnect the PV array during distribution maintenance or storm conditions to ensure lineworker and public safety. Separate metering also improves utility visibility and control of distribution system conditions to help manage power quality issues such as voltage fluctuations and power flicker that may affect customer load devices. While this configuration does support more sophisticated tariff designs described below, a utility could continue to net meter such customers.

[26] For a summary of net metering programs at the largest public power utilities, see American Public Power Association, *Public Power Utilities: Net Metering Programs*, (April 2014), available at: www.publicpower.org/files/PDFs/Public_Power_Net_Metering_Programs.pdf.

[27] For a more detailed discussion of cross-subsidies, see American Public Power Association, *Solar Photovoltaic Power: Assessing the Benefits & Costs* (2014), available at: http://publicpower.org/files/PDFs/74%20Solar-Photovotalic%20Power.pdf .

Net metering may also result in a significant cost shift associated with electric energy and generating capacity costs. As illustrated in PowerPoint slides used in Mr. Mosher's presentation during the FTC's solar workshop, distributed PV output may coincide with a utility's peak load on some days – or it may not, depending on when customer loads are highest on the utility's system. Many utility systems peak late in the afternoon or early evening, after solar PV output has fallen to a small percentage of the daytime peak. In the absence of widespread customer energy storage or new technologies that shift customer loads to mid-day periods, solar PV capacity does not avoid the need to construct and dispatch generating resources to meet the peak loads of utility customers. However, customer-side, distributed and utility-scale PV will all affect the mix of generating capacity that utilities procure to meet load. California in particular is already increasing its use of fast-ramp natural gas combustion turbines to follow the net variability of customer loads and renewable resources that are being dispatched to meet state renewable portfolio standards. The distinguishing fact here is that utility scale and even larger scale distributed resources are dispatched against prevailing wholesale market prices and the operational limits imposed by system operators. Customer-side distributed solar PV, when subject to net energy metering, is completely insulated from the day-ahead and real-time market price signals that all other generators see. And except during unusual electric spot market conditions, they are compensated at a retail NEM rate that substantially exceeds the market value of the energy.

California provides a leading example of the wealth transfer effects of net energy metering. A study conducted by the California Public Utilities Commission revealed that the median household income of residential customers installing rooftop solar over a thirteen-year period was nearly 35% higher than the median income of all utility-served households. With net energy metering paying the full retail rate in California, this income differential translates to a subsidy to upper income households installing rooftop solar from households with decidedly lower incomes.[28]

Estimates of total cross-class subsidies vary, but one study put the total cross subsidy for California ratepayers at $1.1 billion by 2020. As solar panels are typically more prevalent in more affluent neighborhoods, less affluent customers are subsidizing wealthier customers (and in many cases, solar leasing companies).[29]

[28] California Public Utilities Commission, California Net Energy Metering Ratepayer Impacts Evaluation, Appendix E (Oct. 28, 2013), available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/NEMReportwithAppendices.pdf.

[29] R. Borlick and L. Wood, *Net Energy Metering: Subsidy Issues and Regulatory Solutions* (Washington, DC: Edison Foundation: Institute for Electric Innovation, 2014), p. 3, available at: http://www.edisonfoundation.net/iei/Documents/IEI_NEM_Subsidy_Issues_EXECSUMMARY.pdf. The report further notes that when customers lease solar systems, the leasing company gets the lion's share of the subsidy rather than the customer.

A very recent study of the cost shifts of residential rooftop solar for Nevada estimates the cost to non-solar customers at roughly $36 million per year.[30] Furthermore, the study concludes that rooftop solar increases total energy costs in Nevada. So while some customers who install rooftop solar may be made better off, Nevada as a whole is made worse off by this action.

Harvard University's Ashley Brown explains that net metering did not develop "as part of a fully and deliberatively reasoned pricing policy."[31] Net metering became the *de facto* pricing mechanism out of convenience and lack of careful study. When net metering rates were first instituted in the 1980s, most meters lacked the ability to do anything more than go backwards and forwards, so utilities could only measure net consumption. With the initial slow penetration of DG, few utilities felt any significant revenue impacts due to net metering. But, as Brown points out, these reasons do not apply to present-day realities. Advanced meters can track power inflows and outflows for small time periods, enabling more complex rate mechanisms. With an increasing number of DG installations and customers, utilities are starting to experience significant revenue losses and non-DG customers are feeling the rate impacts.

A numerical example provided by the Southern California Public Power Authority (SCPPA) Rate Design Working Group helps explain why net metering creates a revenue shortfall.[32]

- Suppose that:
  - Utility rate = 12 cents/kWh (5 cents/kWh energy + 7 cents/kWh fixed)
  - Consumption falls by 1 million kWh
- Then:
  - Revenue falls by $120,000 (= 1 million kWh x 12 cents/kWh)
  - Avoided cost falls by $50,000 (= 1 million kWh x 5 cents/kWh)
  - Fixed costs unrecovered due to reduced consumption is $70,000 (= 1 million kWh x 7 cents/kWh)
  - *$70,000 of fixed costs are borne by the remaining, non-DG customers, which is a cross-subsidy.*

When fixed costs are recovered through a variable charge, "the utility can be exposed to a revenue loss that exceeds the fuel and O&M expenses that were avoided — because customers reduced their energy consumption."[33] This leads to further rate increases, upsetting remaining customers. SCPPA states that, "Without structural changes to traditional rates, utilities will be required to increase their rates more frequently in order to maintain existing reliability standards and meet financial responsibilities contained in their bond covenants."[34]

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[30] Energy+Environmental Economics, *Nevada Net Energy Metering Impact Evaluation 2016 Update*, p. 7 (Aug. 17, 2016), available at http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf.

[31] A. Brown, "Net Metering: The Dark Cloud in a Sunny Sky," May 27, 2015, p. 2, available at http://blog.publicpower.org/sme/?p=576.

[32] Southern California Public Power Authority Rate Design Working Group. *Updating Traditional Rate Design in the Electric Utility Industry*, p. 7 (Nov. 2014).

[33] *Id*. at 6.

[34] *Id.*

7. State Policymakers Are Addressing Issues Surrounding Solar DG

State policymakers — including legislatures, regulators, state energy agencies — are addressing a range of solar DG issues that include rate design, renewable benefits, clean energy portfolios, renewable energy credits (RECs), consumer options to buy or produce green energy, interconnection policies, micro-grids, energy storage, advanced metering, consumer protection, and more. These issues are policy issues best left to elected officials and state regulatory bodies who can make decisions about the appropriate level of subsidy for new technologies and balance the interest between consumer groups, technology and reliability. This section summarizes state inquiries into two of these issues, namely rates for rooftop solar (including the value of solar) and technology options.

Rooftop Solar Rates and Value of Solar

The NC Clean Energy Technology Center (NC CETC) found that, "[i]n 2015, regulators, lawmakers, or utilities in at least 46 states studied, proposed, or enacted policy changes pertaining to net metering, valuation of distributed solar, [and] fixed or solar charges…"[35] The only states not taking significant actions related to solar policy in 2015 were Alabama, North Dakota, and Wyoming. The key issues addressed in 2015 include:

- **Net Metering vs. Net Billing**: Forty-one states have mandatory net metering policies that allow solar and other self-generating customers to sell excess power to the utility. States are beginning to consider a change in policy from net metering to net billing, in which the customer is compensated for power production at the utility's avoided cost rate rather than at the full retail rate. Hawaii, Nevada, and Mississippi enacted net billing policies in 2015, with Maine and Louisiana expected to do something similar this year.[36]
- **Fixed Charges**: Sixty-one utilities in thirty states proposed increases in fixed charges in 2015, with thirty-seven regulatory approvals and sixteen regulatory denials reached in 2015.[37]
- **Solar Charges**: In 2015, there were twenty-one pending or decided utility proposals in thirteen states to add or increase charges on solar DG customers, mostly for new or

[35] N.C. Clean Energy Technology Center, *50 States of Solar, 2015 Policy Review* (Feb. 2016) at 11, available at https://nccleantech.ncsu.edu/wp-content/uploads/50sosQ4-FINAL.pdf.

[36] Maine's Governor Paul LePage recently proposed to do away with net metering for solar DG. LePage's proposal includes a three-year grandfather period that would allow residents who have installed solar panels to recover some of their investment and proposes to replace the state's net metering program with a market-based approach. In December 2015, the Louisiana Public Service Commission opened a proceeding to explore changes to net metering policies (Docket No. R-33929); this proceeding is ongoing.

[37] In the first quarter of 2016, 26 utilities in 18 states had proposals for increased fixed charges on residential customers pending or decided, and of the seven decisions made in the quarter, three proposal were denied, two were granted, and two were granted at a lower increase. *See* N.C. Clean Energy Technology Center, *50 States of Solar: Q1 2016 Quarterly Report* at 32.

increased demand charges on solar customers. Thirteen utilities proposed such demand charges, although NV Energy was the only investor-owned utility to obtain approval of its solar charges. We Energies solar charge was approved by regulators in December 2014, but was later struck down by the Dane County Circuit Court.

- **Solar Valuation Analysis**: Nine states launched formal examinations of the value and costs and benefits of solar or DG, net metering policies, and potential cost-shifts between solar and non-solar customers.

Regulatory Research of Issues Surrounding Solar DG

In addition to the state-level proceedings, numerous regulatory and research organizations have produced manuals and papers discussing new rate design options meant to address net metering and related subsidy concerns. The National Association of Regulatory Utility Commissioners (NARUC) is currently developing a manual on DG resource compensation that explores various options open to utilities.[38] Lawrence Berkeley National Laboratory has initiated a series of papers entitled the "Future of Electric Utility Regulation" (FEUR)[39] that address rate design and other emerging issues.

Other papers explore specific rate design options. Some of the broad categories of options include:

Residential demand charges: Demand charges have not traditionally been included in residential rate tariffs, though they have long been a feature of most commercial and industrial tariffs. A demand charge assigns a cost to the customer for the relative strain the individual customer places on system resources. Demand charges that are based on customer usage during times of system peak demand can help shave usage during these times, thus alleviating the strain on system resources. While demand charges can help assure better cost recovery, they can also lead to increased bills to customers who cannot shift usage or who do not understand these new charges.[40]

Increased fixed charges: Most of a typical customer's bill is based on a volumetric, per kWh charge, even though a significant portion of a utility's costs are fixed. Some utilities have increased their monthly customer charge in an attempt to recover those fixed costs. Though this

[38] National Association of Regulatory Utility Commissioners, Staff Subcommittee on Rate Design, *NARUC Manual on Distributed Resources Compensation*, July 21, 2016, available at: http://pubs.naruc.org/pub/88954963-0F01-F4D9-FBA3-AC9346B18FB2.

[39] Access to all the LBNL reports in the series can be obtained at: https://emp.lbl.gov/future-electric-utility-regulation-series.

[40] For research on customer experiences with demand charges, see James Sherwood et al., *A Review of Alternative Rate Designs: Industry experience with time-based and demand charge rates for mass market customers* (Rocky Mountain Institute, May 2016, 50. Paper available at http://www.rmi.org/alternative_rate_designs. As part of the FEUR series, Ryan Hledik and Jim lazar debate the pros and cons of demand charges. Ryan Hledik and Jim Lazar. *Distribution System Pricing with Distributed Energy Resources* (Lawrence Berkeley National Laboratory, May 2016).

better aligns costs and revenues, increased fixed charges may have disparate impacts on low-use and low-income customers.[41]

Buy-all, sell-all: Under a buy-all, sell-all approach, solar customers are metered for the energy they consume from the utility at the retail rate, and are separately metered for the electricity they supply to the grid. The price for electricity sold back is set at a different rate (avoided cost, value of solar, etc.).[42]

Value of Solar: Austin Energy, the municipal utility of Austin, Texas became, in October 2012, the first U.S. utility to offer a Value of Solar Tariff (VOST) for residential customers with solar PV systems. VOST is intended to reflect the true value of distributed solar energy to the utility. Its calculation reflects the projected costs that are avoided by the utility, including line losses, fuel, fuel price hedges, new generation capacity, transmission, distribution, and environmental externalities. The credit, developed by the utility and Clean Power Research, is adjusted annually, and had values of $0.128, $0.107, and $0.113 per kWh in years 2013 through 2015, respectively, which were far above the prices of electrical energy set in Texas' wholesale power markets. The VOST replaces net metering for residential solar PV systems that are sized no larger than 20 kW. Under the VOST, residential customers are billed for all electricity consumed in a billing period and are credited for electrical energy generated by their PV systems.[43]

Time-of-use rates: The increased penetration of AMI enables utilities to establish more granular rates based on the time of day. Time-of-use (TOU) or time-varying pricing (TVP) sets rates higher at certain peak times of the day or season. There are several variations, including critical peak pricing (CPP), where rates are set very high for a narrow band of hours when the system is particularly strained – for example during August heat waves. TOU/TVP send price signals that encourage conservation and even potentially help customers lower bills by reducing usage at high-cost times. These rates also better reflect marginal cost. But as with demand charges, not all customers are able to shift usage. Generally, they also require AMI, and system-wide implementation may be cost prohibitive, depending on the utility's circumstances.[44]

Depending on the size, technological capabilities (AMI vs. non-AMI), statutory and regulatory directives, regional market conditions, and other considerations, these rate design options will not be equally applicable to all utilities. Discussions about rate design will thus be somewhat localized, and a one-size-fits all approach should thus be avoided.

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[41] American Public Power Association, *Residential Consumers and the Electric Utility of the Future* (June 2016) (prepared for the American Public Power Association by Janee Briesemeister with the assistance of Barbara R. Alexander), available at http://publicpower.org/files/Residential%20%20Utility%20of%20the%20Future_final.pdf.

[42] Hledik and Lazar, *Distribution System Pricing*, *supra* n.40, discuss this option.

[43] For an explanation of how Austin Energy established its VoS rate, see Karl R. Rabago, et al. *Designing Austin Energy's Solar Tariff Using a Distributive PV Calculation* (Austin, TX: Austin Energy, 2013).

[44] For a general overview of TOU/TVP, see Mina Badtke-Berkow, et al. *A Primer on Time-Variant Electricity Pricing*. (Environmental Defense Fund, 2015); Sherwood et al, *A Review of Alternative Rate Designs;* Jim Lazar and Wilson Gonzalez. *Smart Rate Design for a Smart Future* (Montpelier, VT: Regulatory Assistance Project, 2015), available at http://www.raponline.org/document/download/id/7680.

8. Public Power Utilities Balance the Interests of Solar DG and Non-DG Customers — Community Solar

A large number of innovative programs demonstrate that the public power business model can find ways to accommodate solar DG that balance the interests of both DG and non-DG customers and continue to fulfill the utility's obligations to provide reliable, low-cost energy and distribution services. APPA would highlight one particularly promising set of options: community scale and community shared solar.

At the end of the first quarter of 2016, fourteen states and the District of Columbia had enacted community solar legislation.[45]

Public power utilities have been in the vanguard of the development of community solar. The community solar model has the utility building a relatively large distributed solar facility at a utility-chosen site and then selling its customers shares of solar panels or of solar output. Customers may buy in by making an up-front payment or by making monthly installment payments. In return for its "ownership" shares, the customer receives a monthly billing credit for the value of the solar energy produced.[46]

Community solar has four advantages over rooftop solar. First, customers who cannot install rooftop solar can participate. According to the National Renewable Energy Laboratory, that's about half of all U.S. households.[47] Second, community solar is often cheaper than rooftop solar.[48] Third, community solar shifts responsibility from the customer to the utility for installing and maintaining the solar panels, and financing them. Fourth, community solar may reduce conflicts between the interests of solar DG customers and non-solar customers.[49]

Public power systems (and rural electric cooperatives) are leaders in developing community solar projects. The projects have elicited strong participation from residential customers who also have input into the investment decisions made by public power utilities. Customers with the

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[45] N.C. Clean Energy Technology Center, *50 States of Solar: Q1 2016 Quarterly Report*, at 28.

[46] U.S. Department of Energy, *A Guide to Community Solar: Utility, Private, and Nonprofit Project Development* (rev. May 2012), available at http://www.nrel.gov/docs/fy12osti/54570.pdf. Updated information on community and shared solar is on the DOE website at http://energy.gov/eere/sunshot/community-and-shared-solar.

[47] National Renewable Energy Laboratory, *Estimating Rooftop Suitability for PV: A Review of Methods, Patents, and Validation Techniques* (Dec. 2013), available at http://www.nrel.gov/docs/fy14osti/60593.pdf. See also National Renewable Energy Laboratory, *Shared Solar: Current Landscape, Market Potential, and the Impact of Federal Security Laws* (Apr. 2015) (reporting that 49% of households and 48% of businesses are unable to host PV solar systems because they rent their spaces or have a lack of suitable owned roof space), available at http://www.nrel.gov/docs/fy15osti/63892.pdf.

[48] Rebecca Kern, "State Policy, Utilities Ignite Community Solar Growth," *Bloomberg BNA Energy & Climate Report*, (Sept. 21, 2015), at 5, available at http://www.bna.com/state-policy-utilities-n57982058595/#!; MIT Energy Initiative, *Report on the Future of Solar Energy*, Section III (May 2015), available at http://energy.mit.edu/publications/reports-studies.

[49] American Public Power Association, *Distributed Generation: An Overview of Recent Policy and Market Developments* (Nov. 2013), available at http://www.publicpower.org/files/PDFs/Distributed%20Generation-Nov2013.pdf.

greatest environmental interests naturally evince strong participation rates. However, community solar projects are being structured to enable a wider segment of customers to participate.

The following sample of solar programs illustrates public power's leadership in this arena.

California

In California, which has nearly half of all solar installed capacity in the United States and over half of all PV solar capacity installed, public power has been a leader in innovative approaches to both community and individual PV solar installations.

The Los Angeles Department of Water and Power (LADWP) has a pilot community solar program that it is expected to generate up to 40 MW. The pilot has two options: an on-site option under which LADWP installs solar systems on customer-owned buildings, owns the solar arrays, and pays customers for the power; and an off-site "roofless solar" option that enables renters or homeowners to subscribe to the energy produced by solar arrays at locations other than the customer's home. Neither of these programs exposes customers to the financial and maintenance risks associated with owning solar DG or with obtaining solar from DG firms under lease or a PPA.[50]

With regard to distributed solar, LADWP has also received City Council approval for a fixed charge that is a hybrid of a customer charge and a demand charge called the Power Access Charge (PAC). The PAC is a monthly fixed charge based on the customer's highest level of energy use in the previous year, and is also based on the residential zone the customer lives in (the zone is based on climate). For example, a zone 1 customer whose highest monthly usage between April 2015 and April 2016 was 700 kWh would be placed in tier 2. Each zone has three tiers based on usage, with the PAC being higher as the tiers increase. Each October LADWP will re-examine a residential customer's profile, and customers may be placed in different tiers based on their highest usage over the previous year.[51]

The Sacramento Municipal Utility District (SMUD) has a SolarShares program that allows customers to purchase output from a solar project on a monthly basis. A solar developer, enXco, builds, owns, and maintains a 1 MW system, from which it sells power to SMUD under a twenty-year PPA. Customers pay a fixed monthly fee that reflects both their power consumption and the quantity of PV (from 0.5 to 4.0 kW) to which they subscribe: the fee rises with the amounts of consumption and subscription, but is fixed for each customer for the life of the program. Customers receive monthly kWh credits for the estimated output of their solar subscription. Although customers pay a premium for solar energy, the effective rate for solar is locked in when they enroll, which acts as a hedge against future price increases. Because of the SolarShares program's limited generating capacity, enrollment has been capped at about 700

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[50] http://www.publicpower.org/media/daily/ArticleDetail.cfm?ItemNumber=45217

[51] LADWP's residential tariff and explanation of the PAC can be accessed at https://www.ladwp.com/ladwp/faces/ladwp/residential/r-customerservices/r-cs-understandingyourrates/r-cs-ur-electricrates?_adf.ctrl-state=wy8isb9vg_4&_afrLoop=428364220010586.

residential customers, which has been fully subscribed and for which there is a waiting list. SMUD has begun development of a new 1.5 MW solar installation project at Sutter's Landing Park, and plans to expand the SolarShares' generating capacity by around 25 MW over the next few years.[52]

Florida

The Orlando Utilities Commission (OUC) has given its customers an opportunity to subscribe to its 400 kW Community Solar Farm solar array and thereby receive solar power without the hassle and costs of installation and ownership. The subscribing customers pay a one-time $50 deposit (refundable after the customer has been in the program for two years), and pay a fixed subscription rate of 13 cents per kWh for the energy produced. This rate is locked in for as long as the customer remains in the program, up to 25 years. This subscription opportunity gives residential renters, who are the majority of OUC's residential customers, the ability to purchase solar energy without having to own a home. The Community Solar Farm's output is sold in 1 kW blocks, equivalent to 112 kWh per month, with a limit of 15 blocks per customer.[53]

Texas

In addition to the VOST program described above, Austin Energy in December 2015 issued a Request for Proposals to contract with a solar company to develop a local community solar project to allow residents the ability to purchase clean, renewable energy from the sun without installing panels on their homes.[54]

Washington State

Seattle City Light has a community solar program under which it has built and maintains two large solar arrays (75 KW and 26 kW) in locations situated for solar exposure and community appeal. All Seattle City Light customers are eligible to buy project shares as small as 28 watts or as large as 3,500 watts. Seattle City Light credits participating customers for their portion of the power produced by the Community Solar array. In addition, such customers also receive a Washington State Production Incentive that is double the production incentive paid to customers who have rooftop solar. The credits and incentives may or may not be sufficient to allow customers to recover their participation investments during the term of the program.[55]

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[52] https://www.smud.org/en/residential/environment/solar-for-your-home/solarshares/solarshares-FAQ.htm

[53] http://www.ouc.com/environment-community/solar/community-solar

[54] http://austinenergy.com/wps/portal/ae/about/news/press-releases/austin-energy-issues-request-for-proposals-for-community-solar-project/!ut/p/a0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOINjCyMPJwNjDzdzY0sDBzdnZ28TcP8DC19jfSDU4v1C7IdFQH5wDpn/

[55] http://www.seattle.gov/light/solarenergy/commsolar.asp

9. New Technologies

State policymakers are also focused on the technology developments that are enabling utilities to offer economic alternatives to rooftop solar and that can be deployed to help consumers better manage their load and energy costs.

Community solar and information management systems on the utility side of the meter have and will continue to increase the value of solar for all customers.

Storage: Storage has often been described as the "silver bullet" that changes everything for the electric utility industry. The state of California has an ambitious program to advance the deployment of energy storage at the utility and customer levels, to both address the load management issues created by renewables, balance the system, provide ancillary services to the grid and increase energy infrastructure resilience.[56] The failure of the Aliso Canyon natural gas storage facility outside of Los Angeles has added new urgency to this initiative.[57] However, in current forms, electric battery storage and other alternatives such as compressed air energy storage and flywheels, are much more effective at providing essential reliability services such as voltage management, frequency response, and instantaneous emergency power at critical nodes, than they are at providing economical sources of electric energy to consumers. Nonetheless, a coordinated package of DERs (including but not limited to solar PV) and energy storage could provide significant benefits to individual consumers and to the grid as a whole. APPA believes that integration into utility operations and planning are key pre-requisites for this outcome.[58]

Information Management Systems: New infrastructure and technologies, such as Advanced Distribution Management System (ADMS) and Distribution Energy Management System (DERMS), may enable utilities to maintain reliability and enhance distribution system resilience.[59] ADMS enhances a distribution utility's understanding of real-time conditions across its distribution system through functions such as automated fault location, isolation, and service restoration (FLISR), conservation voltage reduction, and volt/VAR optimization. With increases in the penetration of DG solar, ADMS can enable a utility to maintain reliability, resilience, and flexibility as it satisfies evolving customer needs. As DG solar reaches even higher levels of

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[56] See http://www.cpuc.ca.gov/General.aspx?id=3462

[57] See: "California Utilities Are Fast-Tracking Battery Projects to Manage Aliso Canyon Shortfall," Green Tech Media, August 18, 2016. http://www.greentechmedia.com/articles/read/california-utilities-are-fast-tracking-battery-projects-to-manage-aliso-can

[58] See: "Utility participation key to driving residential storage growth," Utility Dive, July 19, 2016, available at:http://www.utilitydive.com/news/utility-participation-key-to-driving-residential-storage-growth/422637/

For a general discussion of energy storage, see "Energy Storage: Changing the Game, Changing the Grid," Public Power, September-October 2015 (Vol. 73, No. 5), available at: http://www.publicpower.org/Media/magazine/ArticleDetail.cfm?ItemNumber=44477

[59] For additional information about ADMS and DERMs refer to National Renewable Energy Laboratory, *Voices of Experience: Insights into Advanced Distribution Management Systems*, prepared for U.S. Department of Energy. Available at: http://energy.gov/sites/prod/files/2015/02/f19/Voices%20of%20Experience%20-%20Advanced%20Distribution%20Management%20Systems%20February%202015.pdf

penetration, as it is expected to do in California, DERMS can allow the utility to dispatch resources on both sides of the meter, forecast supply and demand conditions up to 48 hours in advance, better integrate AMI data with other utility systems, with outage management, and weather systems, and communicate with third party and aggregator systems.[60] Technological advancements on the customer side of the meter will also increase the value of solar to both the customer and the utility's non-solar customers.

Advanced Meter Infrastructure: More than 52 million advanced infrastructure meters (AMI) have been installed in residences in the United States. These meters measure consumption in increments as short as 15 minutes and transmit consumption information back to the utility, thus enabling relatively low-cost implementation of time-differentiated rate. The advanced meters facilitate two-way flow of information that provides customers with usage, price, and cost information on a more frequent basis than the typical monthly bill. Installation of a second communication device[61] on advanced meters enables the meters to communicate with a Home Area Network (HAN), which in turn can transmit usage, voltage, and generation data to an in-home display about every eight seconds. The information communicated through the in-home display can be connected to a customer's Wi-Fi network and Wi-Fi connected programmable energy-consuming devices that can respond to price signals and other information. The meters can also send and receive information about DG solar units that can be beneficial to both the utility and the residential dg solar user.

Smart Inverters: Policymakers are also considering technology enhancements for the DG solar customer, in particular the smart inverter. All solar PV arrays require an inverter system to convert Direct Current (DC) electricity from the array to the Alternating Current (AC) flowing on the distribution system and through the wiring systems within homes and businesses. Smart inverters can be installed with software that will regulate voltage to prevent sudden voltage drops on DG solar units triggered by passing cloud cover, thus avoiding or reducing the need for costly distribution infrastructure upgrades. The smart inverter is increasingly made a regular component of solar PV installations. The California PUC adopted a recommendation of the California PUC Smart Inverter Working Group to require smart inverters for all new solar PV installations interconnecting with the distribution system.[62]

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[60] J. St. John, *Inside SDG&E's Plan to Optimize the Distributed Grid of the Future*, Greentech Media, May 16, 2014, available at: http://www.greentechmedia.com/articles/read/sdge-and-spirae-break-new-ground-on-the-grid-edge

[61] Such devices work through commonly available communication networks such as broadband over powerlines, power line communications, fixed radio frequency networks, and public networks (landline and cellular).

[62] Smart Inverter Working Group, California Public Utilities Commission, *Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources: Smart Inverter Working Group Recommendations*, January 14, 2014, available at: http://www.energy.ca.gov/electricity_analysis/rule21/documents/recommendations_and_test_plan_documents/Recommendations_for_updating_Technical_Requirements_for_Inverters_in_DER_2014-02-07-CPUC.pdf and *Recommendations for Utility Communications with Distributed Energy Resources Systems with Smart Inverters: Smart Inverter Working Group Phase 2 Recommendations*, February 28, 2015, available at:

The combination of emerging technology on both sides of the meter should eventually enable a customer to benefit from the utility's ability to seamlessly integrate rooftop solar and other significant changes in the customer's energy and load profile.[63]

10. Solar DG Raises Significant Consumer Protection Challenges

The FTC has an important educational role, working with the states, utilities and solar DG providers, to ensure that potential solar DG customers are informed about the options available to them and are protected from providers who use deceptive marketing practices or otherwise take advantage of information asymmetries, which have lead some customers to make uninformed and ill-advised decisions about solar DG.

Solar DG sellers and lessors are typically not regulated by the state public utility commissions as are investor-owned electric utilities.[64] State regulation of DG providers may face legal challenges due to the difficulty in defining the DG provider as something similar to a utility company.

Some states have established expedited, consumer-friendly procedures for the installation of PV arrays and interconnection with the host distribution utility. However, expediting the installation and interconnection process does not ensure that potential solar DG customers will make informed, prudent decisions or protect them from unscrupulous sellers. This leaves residential solar as an important consumer protection challenge with inconsistent attention across the U.S. by consumer-protection and law-enforcement authorities.

This section attempts to outline some of the problems that public power and other utilities have seen as consumers consider solar DG.

Consider first a homeowner who is considering to purchase a solar DG system. This transaction may involve a large cash outlay or a long-term financing arrangement. The return on this investment comes from predicted savings on the utility bill over a long period (for example, 20 years). A solar DG seller can promote the sale based on erroneous or exaggerated projected increases in the customer's utility bills over this period. Homeowners may lack information to check the seller's projections and are usually unable to make such long-term forecasts

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http://www.energy.ca.gov/electricity_analysis/rule21/documents/SIWG_Phase_2_Communications_Recommendations_for_CPUC.pdf.

[63] See for example this story on utility deployment of smart inverters and rooftop PV undertaken by Arizona Public Service Corp. and the Electric Power Research Institute:

http://www.greentechmedia.com/articles/read/Smart-Inverters-in-Action-Initial-Findings-From-APS-Utility-Owned?utm_source=Solar&utm_medium=Newsletter&utm_campaign=GTMSolar

[64] For example, the Arizona Corporation Commission held that Solar City Corporation was not a public service corporation when it provided services through a PPA to schools, governmental entities, or non- profits and when it only provided energy to a single customer, upon whose property the energy system was located. *In the Matter of the Application of SolarCity Corp.*, Decision No. 71795, Docket No. E-20690A-09-0346 (Ariz. Corp. Comm. July 12, 2010), available at http://images.edocket.azcc.gov/docketpdf/0000114068.pdf.

themselves. This is hardly surprising, since the decision to install solar DG is similar in its complexity to a utility's decision to build its own generation or sign a long-term contract to buy power in the wholesale market to serve its customers. Moreover, projected utility bills depend not just on the utility's projected costs of service, but also on regulatory decisions (such a continuation of net metering policies) and other public policies.

If the solar DG system does not perform as promised — for example, it does not produce the expected energy output — the customer's savings will be lower than predicted. The solar DG seller may have exaggerated the system's potential energy output or its expected energy output as installed in the particular location. The homeowner, once again, may not be in a position to question these technical details. Moreover, the homeowner may not appreciate that the performance of solar PV panels typically degrades over time and will degrade if the panels are not kept clean.

Finally, the homeowner's solar DG equipment (panels, inverters, control systems) may simply fail. The homeowner may not appreciate these risks of failure and whether warranties or insurance will pay for equipment repair or replacement.

Two-thirds of solar DG systems are provided to homeowners under long-term leases or power purchase agreements.[65] If the homeowner does not own the solar DG system but leases it from a third party in exchange for monthly payments, many of the above issues remain — the predicted savings may not arise or the solar DG system may not work as advertised. But a long-term lease also creates additional consumer-protection issues.

Solar lease agreements are complex, long-term financial arrangements that can create problems for the homeowner over the agreement's term (typically 20 years). They require sound financial analysis to determine whether the lease is beneficial compared to solar DG ownership or no installation. Such analysis is complicated by the many factors that may influence the relative value of the lease arrangement and the alternatives, including the terms of the lease, the utility's projected costs of service, regulatory decisions, tax and renewable energy credits, and other public policies.

A long-term lease has both financial and operational consequences. The owner/lessor of the solar DG system may fail to meet its maintenance obligations under the lease, and the system's performance may degrade or the system may fail. This may occur due to the lessor's failure to find reliable local service vendors, or the lessor selling its ownership interest and lease obligations to another party who does not meet these obligations. Or the lessor may simply go out of business.

[65] Liam Denning, *The Not-So-Simple Life for Solar* (June 8, 2016), available at https://www.bloomberg.com/gadfly/articles/2016-06-08/solarcity-loan-program-no-simple-fix. This article also describes a new solar loan product announced by Solar City in 14 states as a vehicle for selling solar DG systems. It is too early to determine whether this model will be better for consumers.

Homeowners may not appreciate how a solar lease can complicate matters if they want to sell or refinance their home. Prospective homebuyers must meet the credit criteria of the solar lessor, which adds a new wrinkle to a home sale transaction.

Solar leases also can affect the home's resale value. Although the resale values of homes may increase when they include owned solar DG, that may not be the case when the solar DG is owned by a third party.[66] A homeowner who purchases and owns solar DG receives the 30% federal tax credit (and any similar state tax credit); however, when the homeowner leases the solar DG, the tax credits go to the third-party owner/lessor, and the terms of the lease may or may not return any of the tax savings to the homeowner.

Thousands of homeowners in Massachusetts have found that their solar lease companies have attached Uniform Commercial Code financing statements to the home's records at the registry of deeds. These statements are an alert that the owner of the house has a leasing contract, and though the homeowner owns the house, the solar company owns the panels. Federal Housing Administration (FHA) rules prohibit FHA loans in such situations, but this condition is typically not revealed to homeowners when they enter a solar lease or PPA agreement.[67]

For its part, APPA is just starting to build a toolkit of consumer education resources to help its member utilities educate their customers on the pros and cons of solar DG, including the resources APPA members can provide to customers to make sure they make informed decisions. The best consumer resource guide we've seen to date was developed by Claudette Hanks Reichel of the Louisiana State University Agricultural Center.[68] Reichel identifies seven basic steps for consumers that want to go solar:

1. Get a home energy checkup.
2. Complete cost-effective energy-efficient home improvements.
3. Understand your utility bills, local incentives (tax credits, rebates, etc.) and rules.
4. Explore solar system types and your available solar access.
5. Weigh buying versus leasing considerations.
6. Get proposals from several reputable, established solar system providers.
7. Analyze costs, projected savings and contracts to make the best choice for you and your home.

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[66] See Hoen et al, *supra* n.13.

[67] H.P. Ryan, "Hank Investigates: Leased Solar Panels", *7 News Boston*, Mar. 10, 2016, available at http://whdh.com/news/hank-investigates-leased-solar-panels/.

[68] "Solar Power for Your Home: A Consumer's Guide," Claudette Hanks Reichel, LSU AgCenter (2015), available at http://www.publicpower.org/files/PDFs/pub3366SolarPowerForYourHome.pdf.

See also: "Solar Power on the Roof and in the Neighborhood: Recommendations for Consumer Protection Policies," Barbara R. Alexander, Consumer Affairs Consultant with the assistance of Janee Briesemeister, Consultant, March 2016, available at:

http://www.opc.state.md.us/Portals/0/Publications/BAlexander.FINAL%20Solar%20Power%20Consumer%20Protection%20Report.March2016.pdf

Public power utilities, as community-owned and operated enterprises, would like to be an effective consumer-education resource for their customers who want to install their own solar arrays, participate in community solar projects, or deploy other new technologies that can help meet environmental goals, conserve energy, improve service quality, and save money. However, these efforts by public power utilities cannot substitute for effective enforcement of consumer-protection laws.

APPA has not undertaken a legal analysis of the FTC's authority to exercise its consumer-protection powers to address these issues. But, unlike the mix of competition and regulation issues described earlier, these consumer-protection issues present a good case for further FTC investigation. APPA respectfully suggests that these consumer protection issues are becoming more important every day and should be an important focus of the FTC.

11. Conclusions

Consumer protections are needed and the FTC can play an important role in providing those protections. The decision to purchase or lease a DG solar system is a complex and potentially confusing transaction for residential customers who have little experience with investments in long-lived assets of this type. With system costs in the tens of thousands of dollars and lease or PPA terms of 20 years or more, residential customers, and perhaps some commercial customers as well, need to be educated and provided with accurate information so that they can make fully informed decisions.

Utilities should be compensated for the services that they provide to DG customers, notably including distribution services, load following, and backup. A fundamental problem with the introduction of distributed solar lies with the legacy rate design applied by utilities throughout the U.S., compounded by the introduction of inefficient net metering tariffs. Residential and small commercial tariffs continue to recover the vast majority of the fixed costs of the wires business through volumetric charges. Although utility rate reform needs are outside the scope of the competition analysis that is of central interest to the FTC, it should nonetheless be noted that the failure of traditional rate structures to anticipate the costs of serving DG, along with the widespread introduction of new rate designs that subsidize DG at the expense of non-DG customers, compromises the financial ability of utilities to support DG and ultimately to deliver reliable full-requirements service. Recent utility ratemaking reforms affecting rates and conditions of sale to customers using solar DG, such as in Arizona, Maine, and Nevada, do not represent a barrier to entry for solar DG retailers but an attempt to unwind existing and growing subsidies to solar DG customers from other customers, and to compensate solar DG customers for the electrical energy they produce at prices that accurately reflect the economic value of that energy.

Modifying utility rate designs consistent with economic costs is not anti-competitive, but is instead needed to ensure efficient outcomes, including the adoption of new services. Residential PV providers' business models are predicated on their being free riders on services provided by utilities that heretofore have not been unbundled and priced separately.

The FTC should be cautious about intervening in the electric industry where regulatory policy remains in flux and actions to protect solar customers may result in raising the costs of and rates for distribution services for the majority of consumers that currently do not have realistic options to install DG solar. Furthermore, the industry is embracing innovative, advanced technologies that will help to enable wider adoption of DG solar and reduce the costs of its increasing penetration. State policymakers are addressing and dealing with the many issues that arise in connection with DG solar growth, including consumer protection.