

# EVALUATION OF COMPROMISE POST-NET METERING MODELS FOR DISTRIBUTED SOLAR ENERGY

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## List of Acronyms

APS: Arizona Public Service  
DER: distributed energy resource  
DG: distributed generation  
DOC: Department of Commerce  
DOER: Massachusetts Department of Energy Resources  
DPS: Department of Public Service  
DPV: distributed solar photovoltaic  
EEI: Edison Electric Institute  
EIA: U.S. Energy Information Administration  
GHG: greenhouse gas  
GIS: Geographic Information Systems  
GW: gigawatt  
GWh: gigawatt-hours  
kW: kilowatt  
kWh: kilowatt-hour  
LBNL: Lawrence Berkeley National Laboratory  
MIT: Massachusetts Institute of Technology  
MTC: market-transition credit  
MW: megawatt  
MWh: megawatt-hours  
PSC: Public Service Commission  
PUC: public utility commission  
PV: photovoltaic  
REC: renewable energy credit  
REV: Reforming the Energy Vision  
SCC: State Corporation Commission  
SEIA: Solar Energy Industries Association  
SMART: Solar Massachusetts Renewable Target  
SREC: solar renewable energy credit  
VDER: value of distributed energy resources  
VOS: value of solar

## Executive Summary

This report explores the opportunities and challenges that the recent rapid growth of distributed solar photovoltaic (DPV) systems and distributed energy resources (DER) present for electric utilities, regulators, and other stakeholders. It reviews recent trends related to distributed solar energy and discusses the strengths and weaknesses of net metering, the means by which DPV system owners in most states are compensated for the electricity that their systems export to the grid. It then evaluates three case studies in which electric utilities, the solar energy industry, and other affected stakeholders worked together to develop a compromise solution for a new compensation model that could replace net metering. It also considers some of the broader, long-term issues, such as energy storage and smart grid technologies, that shape the context in which future decisions about solar energy policy must be made. It concludes by evaluating the appropriateness of net metering in the short vs. long term, and by discussing the factors that state policymakers must consider when developing a post-net-metering policy to compensate DPV customer-generators.

### *Distributed Solar Energy and Net Metering*

Under net metering, the excess electricity generated by DPV systems is credited to the customer-generator at the applicable retail electricity rate. At the end of each billing period, system owners pay only for the “net” amount of electricity they consumed. Net metering is allowed in most states, including Virginia, although each state’s policy varies on factors such as system capacity limits, the extent of fees and/or connection charges, etc. For example, in Virginia the maximum DPV system size that can utilize net metering is 20 kilowatts (kW) for residential systems, 500 kW for agricultural systems, and 1,000 kW for non-residential systems. Virginia also has an aggregate capacity limit, applied to all net-metered renewable energy systems (solar, wind, etc.) equal to 1% of each electric utility’s adjusted peak-load forecast for the previous year.

The cost of DPV systems has dropped by over 60% since 2009, and total DPV capacity has grown dramatically in Virginia and across the nation. However, DPV still provides a tiny fraction of total electricity consumption, less than 0.05% in Virginia. For Virginia’s major, investor-owned utilities, DPV capacity represents only about a tenth of a percent of total peak demand. However, that percentage is close to or above 0.5% in a few electric co-op service areas.

Concerns with net metering are primarily based on the fact that electricity customers, regardless of whether they own a DPV system, require the same amount of generation, transmission, and distribution infrastructure to meet their electricity needs at night, and at other times when DPV systems are not operating at full capacity. This leads critics to argue that the lost revenue from the growth of DPV systems will leave electric utilities unable to pay for the costs of needed generation capacity and other assets. In addition, high concentrations of DPV systems could potentially cause technical problems to the distribution grid, creating additional costs. Critics contend that utilities will pass all of those costs on to consumers, leading to “cross-subsidization” of DPV customers by non-DPV customers.

Solar proponents contend, however, that DPV provides numerous benefits to electric utilities and their customers, including: the avoided energy costs that occur when DPV production reduces the need for centralized electricity generation; reduced need for capital investments in centralized generation systems, transmission lines, and distribution infrastructure; grid support services that increase stability and resiliency; avoided financial risks; environmental benefits including reduced greenhouse gas (GHG) emissions, and job creation and other economic development benefits.

In response to the concerns listed above, some states have placed various restrictions or fees on net metering. Others have gone as far as to discontinue net metering altogether. This debate has also inspired a number of “value of solar” studies, which seek to identify the true net cost or benefit that distributed solar electricity provides to the grid by quantifying the many component values identified above (avoided energy costs, grid support services, etc.).

### *Research Approach*

This report explores the potential for “post-net-metering” policies that accurately reflect both the costs and benefits of DPV and are thus palatable to electric utilities, the solar energy industry, utility customers (both DPV owners and non-owners), and other relevant stakeholders. Our work began with a comprehensive review of existing literature on net metering and other policies for distributed solar energy. Through this process we identified three case studies – from Maine, Minnesota, and New York – in which a coalition of stakeholders collaborated to develop a new mechanism for assessing the value of distributed solar energy and compensating customer-generators.

Our research involved telephone interviews with relevant stakeholders in the three case study states, including those representing electric utilities, the solar energy industry, other solar energy advocates (e.g., from environmental or consumer groups), and state government agencies. We also interviewed four national experts on distributed solar energy policy, each of whom represented a specific affiliation or point of view: a university faculty member; a staff member for an organization representing state public utility commissions; a policy analyst from a national research laboratory; and a staff member for an organization representing investor-owned electric utilities. The interview questions addressed the outcomes that the participants would like to see achieved through DPV regulations and ratemaking, their perceptions of the specific strengths and weaknesses of net metering and the various alternative models, and broader issues about electricity grid policy (see questions in Appendix A).

### *Strengths and Weaknesses of Net Metering*

All research participants were asked to identify the strengths and weaknesses of net metering, as well as the key outcomes that they feel should be achieved through the regulation of DPV systems and compensation of DPV customer-generators.

The primary themes to emerge through the discussion of key outcomes were fairness and cost-effectiveness. As would be expected, solar energy representatives discussed the need to fairly value the contributions of DPV, while electric utility representatives emphasized avoiding the cross-subsidization of customer-generators by non-participating customers. However, in many cases the electric utility representatives and solar energy advocates also acknowledged the validity of each other’s interests and concerns. Similarly, several of the state government representatives and national experts expressed the need for fair compensation and market access for existing and potential DPV customer-generators, as well as the need for fair outcomes for non-solar electricity customers.

When asked to discuss how their desired outcomes could be achieved, the majority of respondents identified the need for more transparent tariffs that send proper price signals to all customers and accurately reflect the true costs of generating and delivering electricity. This is consistent with the primary limitations and problems that they identified with net metering. Those limitations included a variety of ways in which it does not properly incentivize DPV and/or capture the value of DPV that solar energy, in combination with other DERs, can offer to the grid.

First and foremost, numerous interview participants argued that net metering discourages customers from investing in energy storage, participating in demand response programs, and/or taking other steps to shift their net loads away from peak-demand periods. They also noted that it discourages west-facing DPV systems, which would reach their peak production later in the afternoon, closer to high-value peak demand times. Also, it does not incentivize the installation of DPV systems in locations where their value to the grid could be maximized (which could include voltage regulation or other grid support services).

Interview participants identified two additional problems with the central logic of net metering. First, it essentially values electricity exported from DPV systems differently based on the type of electricity customer that owns that system (i.e., residential customers are compensated at residential retail rates, while commercial customers are compensated at commercial retail rates). Second, some argued that it does not provide long-term price assurances for either ratepayers or utilities.

While these comments suggest the need for drastic changes to DPV compensation schemes and broader electricity rate structures, several participants also stressed the need for practical, incremental changes that maintain some level of continuity. In addition, despite the aforementioned concerns, several participants noted that net metering retains some appeal. This is primarily due to the fact that it is relatively simple and easy for customers to understand. Some participants also argued that net metering provides a good approximation of the value that distributed solar provides to the grid, noting that many VOS studies have calculated total net values that are roughly equivalent to existing retail rates.

#### *Key Characteristics and Benefits of Proposed Post-Net-Metering Models*

The post-net-metering models from the three states were developed via collaborative stakeholder processes involving representatives of electric utilities, the solar energy industry, and other relevant interests. All drew from the results of a VOS study to identify distinct component values for the electricity produced by DPV systems (i.e. a value for avoided energy costs, a separate one for capacity costs, etc.), or in the case of Minnesota, a method for calculating those values within each utility service area. Each would replace net metering with a new compensation rate based on the sum of those component values, which would be offered to new customer-generators via a fixed long-term contract (existing DPV customers would be grandfathered in to net metering for many years). To varying degrees, these new rates would account for the unique “temporal and locational” values that solar can provide at different times and places (e.g., electricity is more valuable at times of peak electricity demand). As with net metering, these new compensation rates would be applied as a credit on customer-generators’ bills for every kWh exported to the grid, which avoids the tax implications and other problems that would arise from framing the arrangement as a “sale” of electricity.

The new tariff would apply to electricity exports in all states, but in Minnesota the rate would also apply to self-generation (i.e., the electricity consumed by DPV systems and consumed on site). In Maine, customers would have had the option to apply the new tariff to self-generation. The three models also varied in terms of how the new tariffs would be calculated in future years. Some additional differences can be found in the ways that the VOS values are calculated. For example, environmental benefits are not incorporated into the tariff that was proposed in Maine.

This report also briefly describes three additional post-net-metering agreements that emerged over the course of our research, in the spring and summer of 2017, in Arizona, Massachusetts, and New Hampshire. Each of those agreements bears some similarity to the case studies described herein.

Nearly all of the interview participants expressed support, albeit sometimes cautiously, for the post-net-metering models proposed in their respective states. In most cases, that support was based on the notion that the new model would place a fair value on distributed solar energy, thus eliminating cross-subsidization concerns. Utility representatives were sometimes more skeptical of how these benefits would be calculated, particularly with respect to environmental benefits.

A key theme to emerge from the Maine stakeholders was that a post-net-metering policy must find the right balance of complexity and simplicity. Some complexity is necessary to capture the nuanced values of DPV, but the model should also be relatively easy to understand and less risky to implement.

The responses from Minnesota indicated that while all DPV stakeholders can theoretically get behind the concept of a post-net-metering model, disagreements about the value of distributed solar energy can make it difficult to find consensus on the details. This is particularly true in the case of environmental values, on which utilities and solar energy advocates can still be quite far apart.

In New York, all stakeholders agreed that the proposed new model would be an improvement over net metering, but some of the same concerns were expressed regarding the complexity of the new model and whether or not it appropriately calculates all of the values of distributed solar energy.

Nearly all of the national experts agreed that a post-net-metering model based on a VOS calculation would have many advantages over net metering. The exception was the representative of electric utility interests, who expressed concerns about how the VOS benefits would be calculated, particularly with respect to environmental values. The utility expert also argued that the environmental benefits of DPV can sometimes be achieved more cheaply, such as through utility-scale solar.

#### *Broader Long-Term Opportunities and Challenges*

All interview participants were asked to comment on broader, long-term opportunities, challenges, and issues related to the role of DPV in an evolving electricity landscape. A few common themes emerged around reforming retail electric rates, incorporating smart grid, demand response, and energy storage technologies, and identifying a proper role for utilities and means of compensating them.

The most commonly cited long-term issue was the need to reform electricity rates for all utility customers, such as by introducing time-of-use rates and/or demand charges. Participants discussed how better rate structures can help encourage the adoption of other DER technologies, including energy efficiency and storage, and can provide incentives for customers to shift their loads to off-peak hours. The need for rate reform has also been cited by both the Edison Electric Institute and the Solar Energy Industries Association, and it has been addressed in several prominent national studies including ones authored by the Massachusetts Institute of Technology Energy Initiative and the U.S. Department of Energy. However, a couple of stakeholders expressed concerns about the efficacy of these proposed new rate structures, including how they could be designed in a way that is readily accepted and easily adoptable by customers.

Several interview participants identified energy storage as a highly-important long-term consideration for the future of the electricity grid. Better, more cost-efficient energy storage options would increase the value of DPV by allowing excess solar energy generated during daytime hours to be released during evening peak demand periods. Improvements in energy storage and inverter technology could also help DPV provide ancillary grid services and serve as a back-up power source during outages.

A couple of stakeholders also mentioned the importance of demand response and smart grid technologies for the integration of DPV into the electricity system. Demand response programs, which incentivize electricity customers to alter their consumption patterns, could help increase the value of DPV by shifting the peak demand curve towards daytime hours. Smart-grid technologies, such as increased automation and two-way communication between the utility and consumers, can also help electric utilities to better utilize DPV and other distributed generation sources.

The growth of solar energy and other distributed energy resources raises questions about the role of utilities in the evolving electricity landscape. Several interview participants suggested that utilities should evolve to a “distributed system platform” model, with less emphasis on providing centralized generation capacity and a greater responsibility for coordinating a vast network of distributed generation, demand response, energy storage, and other DERs. They noted that such a shift in utility responsibility would require new forms of regulation that allows utilities to take on those distributed platform responsibilities and generate revenue from them.

#### *Short and Long-Term Implications of Net Metering*

The relative benefits of net metering versus potential post-net-metering models must be considered in both the short and long term. This is particularly true when considering the question of cross-subsidization, which rests on the assumption that the value of electricity exported by DPV systems is worth less than the applicable retail rate. Recent reports by Environment America and the Lawrence Berkeley National Laboratory (LBNL) evaluated numerous VOS studies from across the country and found that, in the majority of cases, the value of solar was calculated as close to, if not well above, the retail rate. The LBNL report further demonstrated that, even in cases where the VOS is conservatively calculated at only 50%- 75% of the retail rate, the extent of potential cross-subsidization is minimal given the very small market penetration of DPV systems within most utility service areas. While no complete VOS analysis has been conducted for Virginia, a partial VOS study by the Virginia State Corporation Commission in 2011 similarly concluded that increasing DPV penetration to 1% of peak demand would increase residential electricity bills by less than half a percent.

However, if DPV market penetration reaches the high levels envisioned by many solar energy supporters, and if the true VOS is determined to be significantly less than the retail electric rate, then the extent of cross-subsidization could be much greater. More importantly, the debate about VOS values and potential cross-subsidization may be unnecessary, as the long-term utility of net metering can be questioned on numerous other grounds. As previously noted, virtually all of the interview participants for this study agreed that net metering has clear limitations in a future distributed electricity landscape. These limitations are due to the fact that net metering is rooted in a fundamentally flawed flat-volumetric retail pricing scheme, and therefore discourages energy storage and other load-shifting behaviors that are needed to maximize solar energy’s overall grid contributions.

#### *Recommendations for a Post-Net-Metering Model*

The findings of this report indicate that an ideal post-net-metering DPV compensation model should have the following key characteristics:

- Offer a tariff for DPV exports that is based on the sum of solar energy’s component values, as determined in an independent VOS analysis for the given state or utility service area.

- Include in the DPV export tariff a means of accounting for temporal values (i.e., the time of day at which exports occur, relative to peak demand), and if possible, locational values (i.e., the unique benefits or challenges that DPV systems provide due to their position on their respective distribution feeders).
- Develop the new DPV tariff as part of a larger overhaul of utility rate structures that more accurately reflects the costs of providing electricity, sends the proper price signals to both DPV and non-DPV customers, and encourages the proliferation of DPV and other DER's including demand response, energy storage, and smart grid technology.

In developing a new post-net-metering model, policymakers would have to weigh the relative benefits of reflecting the value of DPV exports as accurately as possible, versus creating a model that is relatively easy to understand and to implement. Additional questions to be addressed would include the extent to which existing DPV customers are grandfathered into net metering, the specific ways in which the new compensation rate would be calculated and applied, and how the new rate would change in the future.

One of the biggest challenges to developing a post-net-metering policy will likely be deciding how environmental benefits are incorporated. This continues to be a primary source of disagreement in the broader debate of the value of solar energy and the extent to which it should be supported through public policy, and the decision to pursue a post-net-metering model does not avoid that question.

In order to maximize the benefit of a new post-net-metering model, it is important to account for how the value of distributed solar energy varies according to the time and place in which it is generated. This is particularly important if the goal is to stimulate investments not only in DPV, but also in energy storage and other DERs, and to further the evolution of a distributed electricity landscape. However, these locational and temporal values will be difficult to capture, as they will require the use of advanced meters and methods of identifying the locations where DPV can provide the greatest value to the grid.

Finally, a key issue discussed throughout this report is that any new post-net-metering compensation model should be part of a broader process to build a more resilient and sustainable distributed electricity system. This includes reforming electricity rates for all customers, developing additional policies to support demand response, energy storage, and smart grid technologies, and establishing mechanisms to compensate utilities for their investments in distributed grid infrastructure and providing distributed system platform services.

# 1. Introduction

The recent growth of distributed solar photovoltaic (DPV) electricity generation systems and other distributed energy resources (DER's) presents new opportunities and challenges for electric utilities, regulators, and other stakeholders. This research intends to provide solar energy stakeholders in Virginia with an understanding of some of the short and long-term issues that arise with the growth of DPV and DER resources, particularly questions of how to compensate DPV system owners (i.e., "customer-generators") for the energy and other services that these systems provide to the electrical distribution grid. It also describes steps taken in other states to address these issues, focusing on three examples (Maine, Minnesota, and New York) where electric utilities and solar energy supporters have collaborated to develop new "post-net-metering" models for compensating customer-generators.

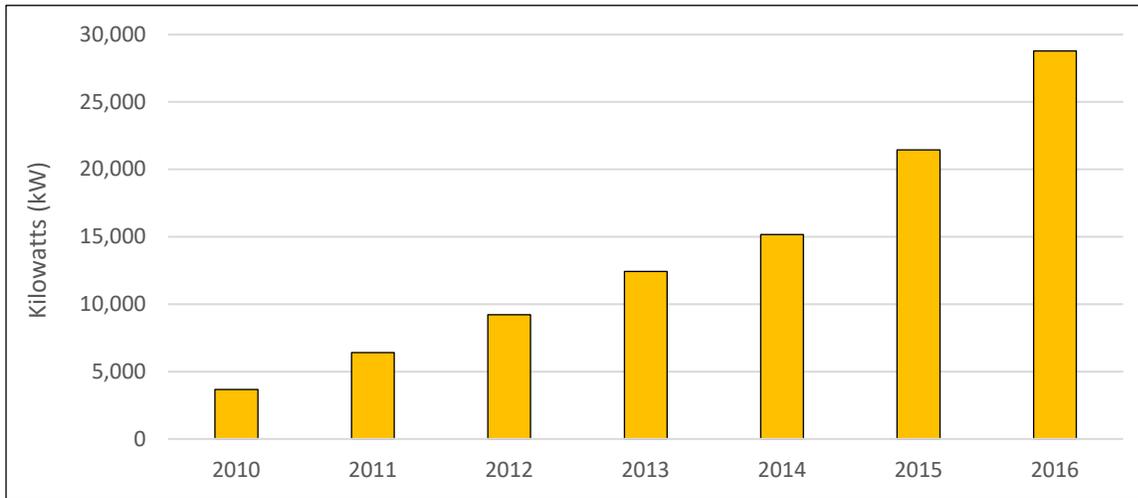
In most U.S. states, including Virginia, customer-generators participate in "net metering" (Columbia Center for Climate and Energy Solutions, 2016). Under net metering, the excess electricity generated by DPV systems is credited to the customer-generator at the retail electricity rate (the residential rate for residential customers, or the commercial rate for commercial customers, etc.). Under this arrangement, system owners pay only for the "net" amount of electricity they consume each month, and in most states they can roll-over their excess generation to the following month. However, net-metering programs can vary considerably based on limits to system capacity (i.e. the maximum size system that can be net-metered), aggregate capacity (i.e., the total amount of net-metered PV allowed), the extent of fees and/or connection charges, or the types of energy systems that are eligible (Menz, 2005).

In Virginia, net metering is allowed for residential DPV systems up to 20 kilowatts (kW) in size, agricultural systems up to 500 kW, and non-residential systems up to 1,000 kW. However, state law limits the size of net-metered systems such that their expected energy generation would not exceed the customer's anticipated annual energy consumption. Residential customers with systems 10 kW or larger pay a monthly stand-by charge, which in the Dominion service territory is \$4.19 per kW of system capacity. In addition, state law includes an aggregate capacity cap, which limits the total operating capacity of all net-metered renewable energy systems (solar, wind, etc.) to "one percent of each electric distribution company's adjusted Virginia peak-load forecast for the previous year." This aggregate capacity limit applies only to "jurisdictional" utilities, regulated by the State Corporation Commission (SCC), which includes investor-owned and cooperative utilities but not municipal utilities (Database of State Incentives for Renewables and Efficiency, 2017b; Virginia Legislative Information System, 2017).

The cost of DPV systems has dropped dramatically in recent years, from over \$8 per watt in 2009 (Barbose & Darghouth, 2016) to \$3 per watt or less in 2016 (National Renewable Energy Laboratory, 2016). Consequently total net-metered DPV capacity has increased dramatically, from just under 1500 Megawatts (MW) nationally in 2010 to almost 10,000 MW by the end of 2015 (US Energy Information Administration, 2017a). In Virginia, net-metered DPV growth has been equally dramatic. According to Virginia State Corporation Commission (2017) data, shown in Figure 1, the state's net-metered DPV capacity has increased from a little over 5 MW in 2011 to just under 29 MW by the end of 2016. Data from the U.S. Energy Information Administration (2017b) places the statewide total at 33.3 MW.

However, DPV still provides a very small percentage of the state's electricity demand. According to data from the U.S. Energy Information Administration (EIA), from 2016, the estimated total generation of from small-scale solar PV was 44,000 megawatt-hours (MWh), as compared to 112 million MWh of total retail electricity sales (US Energy Information Administration, 2017a), indicating that DPV production accounts for less than 0.05% of total electricity consumption in the state.

**Figure 1. Total Net-Metered Solar PV Capacity in Virginia, 2010 – 2016**



Source: Virginia State Corporation Commission, 2017

Table 1 shows that net-metered renewable energy capacity, as a percentage of peak load, varies greatly among Virginia’s jurisdictional utilities. As of 2016, per EIA data, this percentage was as low as 0.07% for the Mecklenburg Electric Co-op, and as high as 0.75% for the BARC electric co-operative.

**Table 1. Peak Load and Net-Metered Renewable Energy Capacity in VA Jurisdictional Utilities (2016)**

Utility Name	Net-Metered PV (MW)	Total Net-Metered (MW)	Percent of NM Capacity from PV	2016 Peak Load (MW)	Percent of Peak from NM Capacity
Appalachian Power*	6.68	8.00	84%	7,363	0.11%
Dominion Virginia Power*	17.46	17.62	99%	16,914	0.10%
A & N Electric Coop	0.22	0.24	94%	161	0.15%
BARC Electric Coop	0.35	0.36	99%	47	0.75%
Central Virginia Electric Coop	0.81	0.82	99%	222	0.37%
Community Electric Coop	0.05	0.05	100%	58	0.08%
Craig-Botetourt Electric Coop	0.14	0.14	100%	25	0.58%
Mecklenburg Electric Coop	0.10	0.10	100%	145	0.07%
Northern Neck Elec Coop	0.18	0.18	98%	91	0.20%
Northern Virginia Elec Coop	2.12	2.12	100%	1,028	0.21%
Prince George Electric Coop	0.06	0.06	96%	80	0.07%
Rappahannock Electric Coop	3.28	2.41	74%	943	0.35%
Shenandoah Valley Elec Coop	1.76	1.79	98%	517	0.35%
Southside Electric Coop	1.27	1.27	100%	267	0.48%

\* The totals shown for Appalachian Power and Dominion Virginia Power include those utilities’ service areas in West Virginia and North Carolina, respectively. See discussion below.

Source: U.S. Energy Information Administration, 2017b

The data in Table 1 for Appalachian Power and Dominion includes the portions of those utilities' service areas that are in other states (North Carolina and West Virginia, respectively). This is because the EIA provides state-by-state breakdowns of those utilities' net-metered capacity, but not of their peak demand. The utilities' respective 2017 Integrated Resource Plans also do not divide their peak demand figures according to state boundaries, but they do provide breakdowns of total electricity sales by state. For Dominion, the 75,969 gigawatt-hours (GWh) of total sales in Virginia in 2016 represented 94.6% of the utility's total sales across the two states (Dominion Energy, 2017, Exhibits 2A and 2C). For Appalachian Power, Virginia accounted for 52.2% (17,847 GWh) of the utility's total internal energy requirements (Appalachian Power, 2017, Exhibits A-1 and A-2). Using these sales percentages as an approximation of how the utilities' peak loads are distributed across their service areas, the estimated Virginia portions of their peak loads would be 3,845 MW for Appalachian Power and 15,999 MW for Dominion. The EIA data lists their net-metered capacities in Virginia as 8.0 MW total (6.7 MW from PV) for Appalachian Power, and 17.6 MW total (17.5 MW from PV) for Dominion. These numbers indicate that, in 2016, net-metered capacity represented about 0.19% of the estimated Virginia peak demand for Appalachian Power, and 0.11% of the estimated Virginia peak demand for Dominion.

### 1.1. The Net Metering Debate

Net metering has become controversial in recent years as electric utilities have raised concerns with the rapid growth of DPV (Tabuchi, 2017). As a result, some states have modified their net-metering laws to include limits on system capacity, various fees, or restrictions on program eligibility (Menz, 2005). For example, in late 2015, the Public Utility Commission (PUC) in Nevada voted to raise fixed fees on DPV customers and dramatically reduce the payments they receive for excess production. This led several leading solar energy to firms shut down operations in the state (ClimateNexus, 2016). Regulators later agreed to grandfather in existing net-metering customers, and restore it for customers in parts of the state, while solar advocates appealed to the state courts (Ola, 2016; Shallenberger, 2017c). Then, a bill adopted in June, 2017 restored net metering at 95% the retail rate, with future step-downs as capacity targets are met, with a future floor equal to 75% of the retail rate (Brooks *et al.*, 2017; Walton, 2017d).

Other states have taken steps to remove net metering altogether, most notably Hawaii, where the market penetration of DPV is much higher than that of other states and the net metering program has been closed to new participants since 2015 (Pyper, 2015). Arizona discontinued net metering in December, 2016, (Shallenberger, 2016a), only to replace it a few months later with a much more complicated program (see description in Section 5.1), developed in a compromise between the solar industry and utilities (Shallenberger, 2017e). Most recently, the state of Indiana also adopted legislation to phase out net metering (Walton, 2017b).

These policy disputes around net metering are the outcome of larger debates about the value that solar energy, particularly DPV, provides to utilities, ratepayers, and society as a whole. Over the past decade, this question has been addressed through numerous "value of solar" (VOS) studies produced by academics, technical consulting firms, non-profit organizations, and state and federal agencies. Their methodologies, assumptions, and findings tends to vary based on whether they are conducted on behalf of an electric utility, the solar energy industry, or a state public utility commission. Over time the different arguments within the VOS debate have begun to crystallize.

Concerns with net metering are primarily based on the fact that electricity customers, regardless of whether they own a DPV system, require the same amount of generation, transmission, and distribution infrastructure to meet their electricity needs at night, and at other times when DPV systems are not

operating at full capacity (e.g., on cloudy days). However, the growth of DPV systems decreases utilities' revenue, which could lead to a situation in which the utilities cannot pay for existing generation infrastructure, turning those facilities into "stranded assets." If the utilities pass those costs on to consumers, then DPV customer-generators will effectively be subsidized by non-DPV customers. On top of these financial concerns, high concentrations of DPV systems could potentially cause technical problems to the distribution grid, such as reverse power flows and substation voltage variations.

On the other hand, solar proponents contend that distributed solar provides numerous benefits to electric utilities, and their customers, beyond simply the avoided energy costs that occur when DPV production reduces the need for centralized electricity generation. First, solar proponents argue that DPV can help offset peak electricity demand, potentially reducing the need for centralized generation capacity (Solar Energy Industries Association, 2015). Second, like other distributed generation technologies – small wind turbines, natural gas micro-turbines, etc. – DPV systems can help reduce the transmission line losses associated with centralized generation (Stanford University, 2010), ease congestion on transmission lines and avoid the need for transmission upgrades (Keyes & Rábago, 2013). Additionally, when much of the electricity produced by DPV systems is consumed on-site, DPV can help stabilize the local distribution grid and reduce the cost of building and maintaining new distribution infrastructure (Rocky Mountain Institute, 2013; Solar Energy Industries Association, 2015). In some situations, DPV may also provide benefits related to grid stability and resiliency, sometimes referred to as grid support services. Other potential benefits include avoided financial risks (e.g., from the volatility of natural gas prices) and the avoided cost of environmental compliance. Finally, many proponents point to the broader environmental and/or economic development benefits that solar energy provides for society, including avoided greenhouse gas (GHG) emissions and new economic development and job-creation opportunities (Rocky Mountain Institute, 2013).

Electric utilities often counter some of these more technical points, for example, by arguing that the intermittent nature of DPV prevents it from displacing future generation capacity costs (Pacific Northwest National Laboratory, 2014). They sometimes point to additional administrative costs, such as establishing new billing systems for net-metered DPV customers (Hallock & Sargent, 2015).

## 1.2 Study Purpose and Outline

The purpose of this report is not to enter into the VOS debate, but rather to explore post-net-metering policies that accurately reflect both the costs and benefits of DPV and are thus palatable to electric utilities, the solar energy industry, utility customers (both DPV owners and non-owners), and other relevant stakeholders. Preliminary research identified three examples from other states – Maine, Minnesota, and New York – in which a coalition of these stakeholders collaborated to develop a compromise solution to replace net metering with another means of assessing the value of distributed solar energy and compensating customer-generators accordingly.

The following section of this report describes the methodology used to identify these three case studies and to assess stakeholder perspectives of their merits with respect to net metering and other potential approaches. Section 3 provides a detailed description of each case study, while Section 4 summarizes our research participants' perspectives on those models. Section 5 reviews examples of other post-net-metering models that have recently been adopted in other states. Section 6 then discusses broader, long-term issues related to DPV grid integration, including electricity rate reform, energy storage and smart grid technology, and proposed "distributed system platform" models for electric utilities. Finally, Section 7 presents some broad conclusions and observations based on the research findings.

## 2. Methodology

Our work began with a comprehensive review of existing literature on net metering and other models for DPV grid interconnection, drawing from the following sources: academic journal articles, professional reports from the National Renewable Energy Laboratory, Interstate Renewable Energy Council, and other governmental and non-governmental organizations, newspaper or magazine articles, posts on relevant websites, etc. Through this process we will identified the three distinct alternative models, further described in Section 3 below.

After identifying these models, we conducted telephone interviews with relevant stakeholders in the three states (Maine, Minnesota, and New York). For each state we sought to interview a total of individuals representing four key stakeholder groups, as follows: a representative of an electric utility, a solar energy industry professional, a relevant state government official, and a solar energy advocate (e.g., from a local environmental organization or consumer group). We also conducted four interviews with national solar energy policy experts. However, we were unable to secure the participation of any individuals representing electric utilities in Maine or a state government agency in New York. Instead, we sought out quotes from existing sources (e.g., newspaper interviews with utility officials, public report from state agencies) that represented the viewpoints of those stakeholder groups on the issues addressed in the interview questions.

The interviews followed a “semi-structured” format, meaning that they addressed a defined list of questions but were open-ended discussions. The researcher asked unique follow-up questions to each participant, as needed, to draw out additional relevant detail or context. Overall, the interview questions addressed the outcomes that the participants would like to see achieved through DPV regulations and ratemaking, their perceptions of the specific strengths and weaknesses of net metering and the various alternative models, and broader issues about electricity grid policy (see the lists of research questions in Appendix A).

Each interview was recorded, and then transcribed by the researchers. The transcriptions were coded to identify major themes and sub-themes for each of the primary research questions. Every comment relevant to an identified theme or sub-theme was entered into a database, allowing the responses to be sorted and analyzed in a variety of ways (e.g., identifying all responses related to the weaknesses of net-metering, sorted by stakeholder type).

This project’s research privacy protocol assured interview participants that they would not be identified by their name, employer, or organizational affiliation, just by their respective states and stakeholder affiliations. The codes used in this report to cite the individual participants’ responses are based on those states and stakeholder affiliations, i.e., a representative of the solar industry in New York is identified as “NY Solar,” etc.

The four national experts each represent a specific affiliation or point of view, as follows: a university faculty member who is a nationally recognized expert on solar energy policy (identified as Expert 1 in the interview results); a staff member for an organization representing state public utility commissions (Expert 2); a policy analyst from a national research laboratory (Expert 3); and a staff member for an organization representing investor-owned electric utilities (Expert 4).

### 3. Case Studies in Post-Net-Metering Policy Development

#### 3.1. Maine's Solar Standard Buyer Program

Policymakers in Maine have been wrestling with solar energy for the past several years. In 2014, the Maine Legislature passed the “Act to Support Solar Energy Development in Maine,” which required the Maine Public Utilities Commission (PUC) to complete a VOS study and evaluate options for increasing DPV capacity in the state (Maine Public Utilities Commission, 2017). Subsequently, the State of Maine Office of the Public Advocate initiated a stakeholder process involving representatives of electric utilities, the solar industry, and other relevant interests. These stakeholders collaborated via multiple work sessions, over a period of six months, and together developed a “market-based” proposal designed to promote solar energy development while avoiding many of the concerns associated with net metering (Maine Public Utilities Commission, 2016; Pyper, 2016).

This process led to a bill, passed in the 2016 legislative session, called “An Act To Modernize Maine's Solar Power Policy and Encourage Economic Development” (H.P. 1120). This bill included the following key provisions:

- Established a solar procurement target of 248 MW to be achieved by the year 2022, divided as follows: 118 MW of “residential and small business” DPV; 25 MW of “commercial and industrial” DPV; 45 MW of large-scale community solar; and 60 MW of “grid-scale” distributed solar
- Established a new means of compensating DPV customer-generators for the electricity that they export to the distribution grid (Maine Legislature, 2016).

Gov. Paul LePage expressed opposition to the bill, leading supporters to offer concessions, including reducing the procurement target to a total of 196 MW and enacting a price cap on DPV exports. This price cap would start at \$0.10 per kilowatt-hour (kWh) and decline to around \$0.06 / kWh, about half the retail electric rate, within 18 months. Despite these concessions, the Governor still vetoed the bill, and a bid to override the veto failed by two votes (Turkel, 2016b). Interestingly, while the bill had the support of the solar industry and its supporters in Maine, it was opposed by a group of national solar energy companies, including Sunrun and SolarCity, that sought to retain existing net-metering rules (Pyper, 2016; Turkel, 2016a).

After the failure of H.P. 1120, the PUC devised a plan to phase out net metering over the course of 15 years, which solar energy supporters roundly opposed (Turkel, 2016c). Most recently, in the 2017 session, the Legislature passed a bill (L.D. 1504) that would override the PUC decision, without restoring the procurement targets or new compensation mechanism that had been included in H.P. 1120. While the state's electric utilities had supported H.P. 1120, they opposed L.D. 1504, thus supporting the planned roll-back of net metering. The governor vetoed L.D. 1504 (Walton, 2017c) and an attempt to override that veto failed in August, 2017, leaving in place the PUC's phase-out plan (Turkel, 2017).

This research focuses on the original compromise proposal put forth under H.P. 1120, which was developed by the Maine Office of the Public Advocate, with input from electric utilities, the solar industry, and other stakeholders. This proposed new mechanism for compensating DPV customer-generators for their electricity exports was based on the following key features:

- The customer-generator would sign a 20-year fixed-price “Customer-sited Solar Contract” to sell its exported solar energy to a “Solar Standard Buyer” most likely an electric distribution utility.

- The Solar Standard Buyer “would aggregate the energy, [renewable energy credits (RECs)], capacity value, and ancillary services potential and monetize these in the applicable markets.” These same buyers would also purchase solar power from larger “wholesale” systems, ensuring that their portfolios would reach “sufficient scale to efficiently monetize the benefits described above” (Maine Office of the Public Advocate, 2015, p. 7).
- The compensation rates for these customer-sited solar contracts would not exceed \$0.20 / kWh, which is the “sum of the direct market-derived values” for distributed solar as found in the state’s 2015 VOS report: avoided energy cost (\$0.078); avoided generation capacity cost (\$0.039); avoided residential generation capacity cost (\$0.005); avoided transmission capacity cost (\$0.016); market price response (\$0.069); and solar integration cost (negative \$0.004). Two additional societal values calculated in the 2015 VOS report – the social cost of carbon / SO<sub>2</sub> / NO<sub>x</sub>, and avoided fuel price uncertainty – were not included when calculating the maximum rate for customer-sited solar contracts.
- The maximum customer-sited solar contract rate would decrease over time as additional thresholds of cumulative installed DPV capacity are reached. For example, the cap would decrease to \$0.19 / kWh when the cumulative capacity reaches 12 MW, \$0.18 / kWh when capacity reaches 19 MW, etc., reaching a floor of \$0.11 or the fixed wholesale rate (whichever is higher) when cumulative installed capacity reaches 100 MW. This is known as a “capacity-based step-down.” These lower rates would apply only to new customers installing DPV at that time, not customers under existing contracts.
- Both the cost of the payments to customer-generators and the revenue from the Solar Standard Buyer’s sale of the aggregated distributed solar energy products would be credited to all customers via the distribution utilities’ existing mechanisms (Maine Office of the Public Advocate, 2015, p. 7-8).
- Existing customer-generators would be grandfathered into net metering for 12 years. Customers participating in the new contract rate would have the option of applying that rate to either their system’s entire electricity production, or just the portion that is exported to the grid after self-consumption (Maine Legislature, 2016).

Similar to net metering, the compensation for the customer-generator’s exported energy would appear as a credit, based on this per-kWh rate, on the customer’s monthly electricity bill. In the near-term at least, compensation to customer-generators would likely have been greater than that which they would have received under net metering (i.e., the contract rate would have been higher than the retail rate).

However, proponents of the proposal argued that it would have avoided cost-shifts and potentially been an economic net-positive for all electricity customers, as the system was designed to more properly monetize the various attributes that DPV provides. The contract rate cap was based on the actual amount of revenue that the Solar Standard Buyer could receive on the market for the aggregated distributed solar energy product, per the estimates in the 2015 VOS study, meaning that in the short term the “customers will not pay more than the best available estimate of the likely benefits to them, even if all of these benefits are not directly monetized by the Solar Buyer.” If the total market value of the aggregated solar energy product were to exceed the contract rate, then non-participating customers would receive a net-benefit. The sale of solar energy purchased from wholesale distributed generators was anticipated to provide even better returns to non-participating customers (Maine Office of the Public Advocate, 2015, p. 8-9).

### 3.2. Minnesota's Value-of-Solar Tariff

In 2013, the Minnesota Legislature passed a comprehensive solar energy bill (H.F. 729) that added a 1.5% solar “carve-out” to its existing Renewable Energy Standard, required investor-owned utilities to enact a community solar program, and established a variety of financial incentives for solar energy. In addition, it set forth a process to establish a new “VOS tariff” option for customer-generators, which utilities could choose to implement as an alternative to net metering. The legislation directed the Minnesota Department of Commerce (DOC) to develop a standardized method for utilities to use in calculating the VOS rate, to then be approved by the Minnesota PUC. Each utility that wished to enact a VOS tariff would then have to produce a VOS calculation that applied the DOC methodology using values specific to that utility’s service area, which would then have to be approved by the PUC before being implemented (Eleff, 2016; Norris, Putnam, & Hoff, 2014; Taylor, 2016).

The legislation included two highly important stipulations. First, the VOS rate could not be below the utility’s average retail rate for a minimum of three years (Taylor, 2016). Second, under an approved VOS tariff, solar customers would be billed for all of the electricity they consume, and would be credited at the VOS rate for all electricity produced by their DPV systems. In other words, at least for billing purposes, customers under a VOS tariff would not self-consume any of the energy produced by their systems. The perceived benefit of this approach was that applying the applicable retail rate to all electricity consumption would allow utilities to still recover infrastructure costs, and those applicable rates could still be adjusted in the future as needed (Norris, Putnam, & Hoff, 2014).

The DOC developed the methodology via a public process that included consultation with electric utilities, the solar industry, and other affected stakeholders. The final methodology report was completed in early 2014, and approved by the PUC shortly thereafter. The original legislation mandated that the VOS methodology include the following components:

- Avoided energy delivery costs
- Avoided generation and transmission capacity costs
- Transmission and distribution line losses
- Environmental benefits

The DOC’s methodology also included an optional location-specific distribution capacity value that utilities could include to encourage DPV systems at high-value locations on the distribution grid. It also included “placeholders” for avoided voltage control values and solar integration costs, which were considered potentially relevant VOS components that could not be accurately calculated at the time. Other key aspects of the VOS methodology are as follows:

- All calculations were based on an economic analysis period of 25 years.
- A near-term level of DPV penetration is assumed when calculating generation capacity and other relevant value components. Future annual adjustments to the VOS calculations would be based on the DPV penetration levels at those times.
- To ensure transparency, each utility’s VOS calculation must include two standardized tables that identify the key input assumptions and value components of their respective analyses.

The DOC study concluded with an example calculation, using standardized assumptions not specific to any particular utility in Minnesota. This example calculation resulted in a total VOS of \$0.127 / kWh, of

which the primary components were avoided fuel costs (\$0.061), avoided generation capacity costs (\$0.021), and avoided environmental costs (\$0.029). Together, these components comprised 87% of the total value, with the environmental costs themselves representing 23% (Norris, Putnam, & Hoff, 2014).

If a given utility were to adopt the VOS tariff, the 25-year levelized value calculated for that utility would be converted to a credit, which would be applied on a per-kWh basis to all generation produced by new solar customer-generators who interconnect subsequent to the implementation date. This credit would then be adjusted for inflation on an annual basis, per Consumer Price Index (CPI) data (Norris, Putnam, & Hoff, 2014).

A new VOS tariff would be calculated each year, based on the latest available data on fuel prices, utility load profiles, DPV penetration, etc. The updated VOS rate would apply to all new customers installing DPV systems that year. Existing customers under the VOS tariff would not be affected by the annual recalculations of the VOS rate, but would see their credit adjusted for inflation as described above (Norris, Putnam, & Hoff, 2014).

The DOC argued that, if set correctly, the VOS tariff would reflect the true value of electricity generated by DPV systems. The cross-subsidization concerns associated with net metering would thus be eliminated. Furthermore, the VOS tariff could support the adoption of technologies, such as advanced inverters, that increase the value of DPV electricity (Norris, Putnam, & Hoff, 2016; Taylor, 2016). However, thus far no utilities in Minnesota have chosen to adopt a VOS tariff for DPV. Media coverage indicates that the utilities have concerns about how the VOS tariff was calculated, particularly with respect to environmental values, as well as the long-term viability of a VOS approach if DPV penetration increases rapidly (Taylor, 2016). These and other concerns are outlined in Section 4 of this report.

### 3.3. New York “Value Stack” for Distributed Energy Resources

In New York, an alternative to net metering is being developed as part of a broader “Reforming the Energy Vision” (REV) process. The REV process was launched by Governor Andrew Cuomo in 2014, and is being led by the State of New York Department of Public Service (DPS). Its stated goals include increasing energy efficiency, renewable energy capacity, and the deployment of other DERs and “advanced energy management products,” including micro-grids and energy storage. The REV process encompasses at least 10 separate proceedings, addressing a wide range of issues such as energy efficiency, low-income affordability, large-scale renewables, etc. The process includes separate proceedings to simultaneously tweak existing net-metering rules and develop a comprehensive replacement “Value of Distributed Energy Resources” (VDER) scheme (Bade, 2016a; New York Department of Public Service, 2015a, 2017a, 2017b).

The VDER compensation mechanism being developed for DPV customer-generators in New York shares many similarities with the VOS tariff option in Minnesota. A key difference, however, is that New York’s new post-net-metering approach is being developed in the context of this larger REV process, which seeks to remedy various structural challenges that limit the market penetration of DPV and other DERs. For example, a DPS staff white paper from early in the REV process notes:

*“Utilities’ earnings are heavily dependent on their capital expenditures, and the long-term security of their earnings is based on the assumption of a growing or stable sales base. Further, utilities cannot earn a return on operating expenses, except by cutting them. Optimally integrating DERs may, though, require increases in utility operating expenses and decreases in capital spending.*

*Consequently there is a financial misalignment between the utilities' economic interest, the interests of third-party DER providers and other service providers, and customers" (New York Department of Public Service, 2015b, p. 3).*

The REV seeks to address these structural challenges and financial misalignments through a thorough overhaul of utility rate structures and practices. The intent is to encourage optimal use of DERs, while ensuring that utilities can still raise the capital needed to build and maintain grid infrastructure and continue to receive a fair return on investment. Other "foundational principles" include maintaining flexibility, establishing appropriate market signals and incentives, and achieving public policy objectives, including the New York State Energy Plan's goals to reduce GHG emissions by 40% and acquire 50% of electricity from renewable sources by 2030 (New York Department of Public Service, 2015b).

The REV envisions a future in which utilities will provide "Distributed System Platform" services, which has been likened to "an air traffic controller that coordinates and facilitates the deployment of various distributed energy resources (DERs) on the grid." In this model, utilities would be able to earn revenue through "traditional cost-of-service investments, earnings tied to the deferral of capital investments, earnings from market-based platform activities and market-based performance measures" (Bade, 2016a). In short, utilities would be able to earn returns on the investments they make in the technology and services needed to facilitate increased use of solar energy and other distributed energy resources.

The REV approach to overhauling utility rates is outlined in the aforementioned DPS staff white paper, which states that "rate design for mass-market customers should begin to place a greater weight on the peak demand of the customer, which is closely related to the cost of the system and which can be managed by the customer to control their electricity costs." The white paper also suggests that a "smart home rate" should be offered "for those customers who want to begin participating as active consumers," and that "usage block" rate structures should be used "to maximize opportunities for low-income customers to participate in DER." In addition, it argues that "demand-based rates of larger commercial and industrial (C/I) customers can also be improved to more closely align rates with system costs" (New York Department of Public Service, 2015b, p. 11-12).

New York's proposed post-net-metering tariff has arisen through the REV Distributed Energy Resources proceeding. This proceeding inspired a collaborative effort on the part of six major electric utilities and three national solar energy companies, known as the "Solar Progress Partnership," to develop a compromise proposal to replace net metering. Their proposal, filed with the Public Service Commission (PSC) in 2016, would grandfather in all existing net-metering customers, as well as any new customers who install DPV systems through 2020. After 2020, new DPV customer-generators would be assigned a new, more accurate tariff, the details of which were yet to be determined (Shallenberger, 2016b).

The PSC subsequently initiated a stakeholder process to develop a process for transitioning from net metering to the proposed more accurate tariff, later dubbed the Value of Distributed Energy Resources (VDER) tariff. In March, 2017, the PSC issued an official order for Phase One of the VDER, which applies only to Community Distributed Generation and "demand-market" commercial sector DPV customer generators (i.e., medium to large commercial electricity customers that pay a demand charge). Residential and small commercial "mass-market" customer-generators will remain on net metering through at least the end of 2019, and any DPV projects that they install by the deadline will be allowed to remain on net metering for 20 years (New York Department of Public Services, 2017c).

The PSC is now in the process of developing a Phase Two VDER mechanism, which will, with few exceptions, transition customer-generators from those “mass-market” customer classes off of net metering. While the details of the Phase Two VDER tariff are yet to be determined, all New York-based stakeholders interviewed for this project believe that it will be similar to the Phase One approach, so the details of that approach are instructive for this research.

The VDER Phase One tariff is based on a “value-stack” approach, in which customer-generators are credited for their exported electricity at a rate determined by a calculation of the various component values of that energy. Unlike the VOS tariff in Minnesota, however, the VDER tariff would only apply to the energy exported to the grid after the customer-generator’s own self-consumption. Additional pertinent details of the VDER tariff include (New York Department of Public Services, 2017c):

- In instances where the VDER tariff is lower than the customer’s base retail rate, customers would be provided a market-transition credit (MTC) to make up all or part of the difference
- Excess credits would be carried over to the subsequent billing month and/or year as applicable.
- The methodology for calculating VDER credits would require the use of advanced inverter and metering technology.
- The PSC order includes provisions intended to limit impacts to non-participants (via a 2% upper bound on the net annual revenue impact for each utility), avoid cross-subsidization among customer classes, and enable the participation of low-income customers.

The value-stack tariff is comprised of four components (New York Department of Public Services, 2017c, p. 15-16, 94-119), each of which must be calculated separately by each electric utility:

- An energy value, based on the day-ahead hourly zonal locational-based marginal price.
- A capacity value, based on “retail capacity rates for intermittent technologies... based on performance during the peak hour of the previous year.”
- An environmental value, based on New York’s latest Tier 1 procurement price of renewable energy credits, as published by the New York State Energy Research & Development Authority (NYSERDA). The current rate is roughly \$0.024 cents / kWh.
- Demand reduction and “locational system relief” values, preliminarily based on each utility’s latest marginal cost study, with better methodologies to be developed as part of Phase Two. The locational system relief value would provide higher compensation to systems located in parts of the distribution grid where DPV production would be most beneficial.

It is important to emphasize the locational and temporal aspects of the value-stack methodology. They demonstrate that the VDER component of New York’s REV process is intended not only to accurately compensate DPV customer-generators for the value of the energy they provide to the grid, but also to send market price signals that encourage those systems to be developed in locations where their value will be maximized.

### 3.4. Comparison of Case Study Models

Each of the three models described here would replace net metering with a more comprehensive tariff structure, in which customer-generators would be compensated according to the sum total of the component values of the energy that they provide to the grid. Each of the methodologies is far more complicated than net metering, with New York’s VDER approach arguably the most complex. Some of the key characteristics of these approaches are compared in Table 2.

**Table 2. Comparison of Post-Net-Metering Models**

Key Model Components	Maine	Minnesota	New York
Compensation based on calculation of component values	√	√	√
Utility participation optional or required	Required	Optional	Required
Existing net-metering customers grandfathered in	√	√	√
Tariff applies to all DPV production, or only exports	Customer Option	All	Exports
Environmental value included in tariff calculation		√	√
Market price response included in tariff calculation	√		
Location-specific values included in tariff calculation	No	Optional	Yes
Future compensation rate for customers once enrolled	Fixed	Increases	Variable
Future compensation rate for new customers	Auto step-down	Re-calculated	Re-calculated
State has mandatory RPS or other solar PV target	√	√	√
State has de-regulated electricity market	√		√

One of the most important differences is that Minnesota’s VOS tariff is optional for utilities to implement, and would apply to all electricity produced by customer-generator’s DPV systems. Participation would be required for all utilities in Maine and New York, and the tariffs in those states would apply only to the electricity that customer-generators export to the grid after their own self-consumption. Customers in Maine would have the option to apply the tariff to their full production.

The tariffs themselves are calculated similarly in all three states, with the key difference that Maine does not include an environmental value in its calculation, but does include a market-price response measure. Also, unlike the other states, New York goes to great lengths to include locational and temporal elements in its tariff calculation.

Finally, future compensation rates are handled differently in each state. The Maine proposal would have provided a long-term fixed-rate compensation for participating customer-generators, with that rate stepping down automatically as certain DPV capacity targets are met. In Minnesota, participating customers would receive a VOS tariff that is automatically adjusted for inflation each year, while the starting tariff for new customers would be re-calculated each year. In New York, rates for both participating and new customers would be re-calculated on a regular basis.

## 4. Interview Findings on Net Metering and Post-Net-Metering Models

This section discusses the broad themes and patterns on net metering and post-net-metering models that emerged from the research interviews. It also includes some secondary source references that identify the positions of stakeholder groups that we were not able to interview (i.e., electric utility representatives in Maine, and government agency representatives in New York).

The primary goal of this analysis is to identify points of common agreement among all stakeholder types, as well as any patterns of disagreement among certain stakeholder types. Where applicable, we also identify unique counter-arguments or alternative perspectives described by one or more interview participants. Direct quotes, shown in italics, are used as representative examples of the themes, patterns, and alternative perspectives that have been identified. These quotes are largely verbatim, but in some cases minor edits are made for clarity and/or consistency of grammar, tense, etc.

The research interviews addressed three primary themes with respect to the regulation of DPV systems and ratemaking for customer-generators: the key outcomes that should be achieved; the strengths and weaknesses of net metering; and the strengths and weaknesses of the various post-net-metering models. Additional research questions addressed other, broader issues related to DPV and/or the electricity system as a whole, and the responses to those questions are summarized in Section 6.

### 4.1. Key Outcomes to be achieved through DPV Regulation and Ratemaking

The primary themes to emerge through the discussion of key outcomes were fairness and cost-effectiveness. Participants also identified a variety of other desired outcomes related to supporting DPV integration and achieving the environmental and grid-related benefits that it provides.

As would be expected, the solar energy representatives discussed the need to fairly value the contributions of DPV, while electric utility representatives emphasized avoiding the cross-subsidization of customer-generators by non-participating customers. Several of the state government representatives and national experts expressed the need for fair compensation and market access for existing and potential DPV customer-generators, as well as the need for fair outcomes for non-solar electricity customers (i.e., avoiding cost-shifts). A clean energy advocate in New York captured both sides of the fairness question, describing the need to:

*“Create a policy that is good for those with distributed resources... and not have it adversely affect other rate payers who do not have the resource to buy the solar panels”* (personal interview, NY Advocate).

Two of the national experts put a slightly different spin on the “fairness” theme, citing the need for open market access and a level playing field between customer-owned generation resources and generation resources that the utilities build themselves. Both of the state government representatives (Maine and Minnesota) emphasized the need to protect non-participating customers, with the Maine representative noting that a fairly small percentage of the state’s residents own homes with un-shaded, properly-oriented roofs that could support DPV systems.

To some degree, electric utility representatives and solar energy advocates also acknowledged the validity of each other’s interests and needs. For example, one of the solar energy representatives indicated the importance of balancing benefits to DPV customers with “the needs of the utility

companies and the grid itself” (personal interview, NY Solar), and another stressed the need to “lower the cost of the grid for everybody” (personal interview, ME Solar). The utility representative from New York said that electricity policy should maintain a viable solar energy industry, and the national expert representing utility interests said that regulatory and rate structures should “allow distributed energy resources to flourish on the system,” while also allowing for “the recovery of those necessary costs to invest in the energy grid” (personal interview, Expert 4).

Several of the solar industry representatives, clean energy advocates, and national experts said that DPV regulation and ratemaking should seek to stimulate DPV markets and/or scale-up DPV capacity. Most of those same stakeholders also pointed to de-carbonization and other environmental benefits as desired outcomes. The state government representatives identified those same objectives, in the context that achieving them would address existing policy goals in their respective states.

Participants were also asked to discuss, in broad terms, how those outcomes could be achieved. A healthy majority of respondents described, in one way or another, the need for more transparent tariffs that send proper price signals to customers and accurately reflect the true costs of generating and delivering electricity. Several stakeholders made points to this effect when discussing the need for better methods of compensating DPV customer-generators:

*“[We should] come up with a set of incentives that are not necessarily geographically consistent, but reflect either different locational values or different temporal values that different solar [and other DER resources] could provide”* (personal interview, NY Utility).

*“[DPV] has moving value and it has locational value, and that’s something that changes considerably over time, and something that needs to be taken into account as you’re looking at these things. Locking in one value for that location over an extended period of time is not really reflective of the cost of providing service to that area”* (personal interview, Expert 4).

*“We need to get more granular, more bidirectional in our appreciation of how these resources operate”* (personal interview, Expert 1)

*“There needs to be a more granular approach to valuing distributed resources”* (personal interview, NY Advocate).

*“We ought to be working towards a smarter, more granular compensation regime”* (personal interview, ME Solar).

The need for more accurate, comprehensive rate structures extends to all customers, including customer-generators, as best described by the national expert from a federal research laboratory:

*“I think the first and most obvious thing is just to have more temporally differentiated rates. At the most basic level, maybe this is just time of use rates with critical peak pricing. Obviously there are more elaborate kinds of dynamic pricing structures that could also be used, but to cash in that temporal variation is important. For distributed resources, it’s also really important, and more difficult, to try to start incorporating locational or geographic factors accurately or to provide some sort of price signals to distributed energy customers about the value at a particular point on the grid in either producing or consuming electricity”* (personal interview, Expert 3).

While these comments suggest the need for drastic changes to electricity rate structures, several participants also stressed the need for practical approaches that employ incremental changes and maintain some level of continuity. This includes using existing regulatory tools, integrated resource planning processes, and traditional cost-effectiveness metrics.

#### 4.2. Strengths and Weaknesses of Net Metering

According to the interview participants, the primary appeal of net metering as a means of compensating DPV customer generators is its simplicity. This point was made by a number of different stakeholders, and is best captured as follows:

*“The biggest benefit is likely to be its simplicity. From a customer perspective, as well as generally from a utility, regulatory, or accounting perspective it’s relatively simple. At least when you’re talking about retail rate and net metering. You put a kilowatt-hour on the grid, you get a kilowatt-hour credit. It’s easy for customers to understand. It’s easy for companies selling solar to communicate”* (personal interview, ME Advocate).

*“The benefit is that it’s relatively simple to understand, and I think that is actually particularly important in the case of nascent markets where you’re dealing with consumers that are really just beginning to understand the technology, or there’s maybe some risk either real or perceived in technology adoption”* (personal interview, Expert 3).

Along these same lines, some stakeholders noted that net-metering policies an appropriate and effective mechanism for supporting early growth of the solar industry, as they “reflect the capabilities and needs of the electric system at the time they were designed” (ME Government, via New York Department of Public Services, 2017c, p. 3).

Another benefit, identified by solar energy representatives, clean energy advocates, and national experts, is that it provides “rough justice” to the value of distributed solar to the electrical grid. In other words, net metering is “not an inaccurate assessment of the value” of distributed solar energy (personal interview, Expert 1), in that “the retail rate is in the order of magnitude of what you might pay if you have a value of solar tariff, which is vastly more complicated” (personal interview, ME Advocate).

To support this argument, a solar industry stakeholder pointed to prior VOS studies, many of which have found that the true value of solar is “pretty close to the average volumetric retail price” (personal interview, ME Solar). However, the rough justice argument does not necessarily indicate that net metering is an appropriate mechanism. As one national expert put it,

*“I don’t think anybody would claim that net metering provides the perfect price signal, but to the extent utility rates as a whole are pretty imperfect, I’m not sure that net metering is any more so”* (personal interview, Expert 3).

The most common criticism of net metering, which was identified by all stakeholder groups and multiple national experts, is that it is an imprecise, inaccurate, and/or antiquated approach to measuring the value of distributed solar energy and compensating DPV customer-generators. Even supporters of the rough justice argument point out that “even if the number is right,” “it’s not based on a transparent accounting of the value of the resource” (personal interview, ME Advocate). Several participants argued that this simplicity can lead to misconceptions. For example, each national expert, aside from the one

representing utility interests, suggested that net metering's simplicity allows for criticisms about cross-subsidization that are, in their opinion, unproven or exaggerated.

Beyond criticizing its simplicity, interview participants of all types identified numerous other limitations or problems with net metering. All utility-affiliated participants raised the previously-discussed arguments about cross-subsidization. For example:

*"[As a net-metered customer] you have the ability, depending on how much you're self-generating, to either zero out your bill or get a bill credit. Yet you're still connected to the system, you still enjoy the backup power system... and that's where the cross-subsidization conversation starts"* (personal interview, MN Utility).

*"[Net metering is] an outdated and expensive subsidy for the businesses that install private solar systems. It also unfairly shifts costs to everyone who pays an electric bill and delays opportunities for solar energy to make a more meaningful difference for Maine's environment and economy"* (ME Utility, via Burns, 2017).

One of those utility representative suggested that net metering was intended to incentivize distributed generation all along, and that this incentive was no longer necessary or appropriate:

*"At that time... it was seen as a policy mechanism to help people who wanted to self-generate. The issues of penetration and cross-subsidization really were not in the conversation at that point in time. I think as the technology changes and the adoption rates change, then it's appropriate to go back and revisit some of these policies"* (personal interview, MN Utility).

In addition, the interview participants pointed out a variety of ways in which net metering does not properly incentivize DPV and other distributed resources, and thus misses out on opportunities to add value to the electric grid:

*"[Net-metering policies] operate as blunt instruments to obscure value and are incapable of taking into account locational, environmental, and temporal values of projects. By failing to accurately reflect the values provided by and to the DER they compensate, these mechanisms will neither encourage the high level of DER development necessary for developing a clean, distributed grid nor incentivize the location, design, and operation of DER in a way that maximizes overall value to all utility customers"* (NY Government, via New York Department of Public Services, 2017c, p. 3)

For example, a utility representative pointed out that net metering provides no incentive for customer-generators to install west-facing DPV systems, which produce electricity late in the afternoon when demand is high and power is most valuable. Likewise, it does not encourage the installation of DPV systems in locations "where the distribution system could benefit from those net injections" (personal interview, NY Utility). A solar industry representative made a similar argument, that net metering provides customers no incentive to use DPV to off-set their loads during periods of high demand.

Extending this argument further, net metering discourages customer-generators from investing in energy storage systems that would allow them to better manage their own loads and/or export power to the grid when it is needed most:

*"[Under net metering], you are allowed to use the energy grid like a battery, even though it doesn't function that way, but to an end user that's sort of the end result. They don't care when they*

*produce or use energy because at the end of the month it's just netted out. That actually inhibits the development of things like actual energy storage, where they could be providing other grid services by bringing that online"* (personal interview, Expert 4)

*"[Net-metering customers] are not responsive to price signals from grid operators, and it doesn't work for storage. If you think distributed storage is a thing you want on the grid, there's absolutely no need for it in a net metering regime"* (personal interview, ME Government).

Solar industry and state agency representatives noted two additional problems with the central logic of net metering. First, it essentially values the electricity that DPV systems export differently based on the type of electricity customer that owns that system, as "you're reimbursed based on the rate of the meter that you're offsetting" (personal interview, NY Solar). If a residential customer-generator receives net-metering credits at the residential retail rate, and a nearby commercial customer-generator receives net-metering credits at a lower commercial retail rate, then the former customer's exported energy is being valued higher. This is true even if the two systems are exporting electricity at the same time and in the same location, thus providing the exact same benefit to the grid.

Customers that pay a demand charge (i.e., industrial and larger commercial customers) present an interesting scenario with respect to the price signals sent under net metering. Per the above argument, such customers are not incentivized to use net metering because the per-kWh rate that they pay is typically lower than that of a residential or small commercial customer. However, depending on their daily usage patterns, they may be able to use a DPV system to reduce their demand charges. In this case the above argument would no longer apply. Furthermore, such customers would be incentivized to invest in on-site "solar plus storage" systems, which could be calibrated to maximize demand charge savings. Nevertheless, the prior point remains that net metering discourages energy storage overall, as the vast majority of individual utility customers do not pay demand charges.

In addition, net metering involves some level of ambiguity over the long-term, for both utilities and customer-generators, as described below:

*"You don't know how much you're going to pay, you don't know how much you're buying, and the price increases over time even though the cost of [solar energy] resources is decreasing"* (personal interview, ME Government).

*"There can be an inherent uncertainty in the long term value stream under net metering, since at any point during a particular system's life cycle the rate structures might totally change and the bill savings a customer receives would totally change"* (personal interview, Expert 3).

Finally, several stakeholders noted that the technology exists to move past net metering, as it is a "relic of a time when meters could only track inflow and outflow of power" (personal interview, Expert 4). Put simply, "it is an analog system, in a digital world" (personal interview, Expert 1).

#### 4.3. Strengths and Weaknesses of Post-Net-Metering Models

All stakeholder participants were asked to comment on the strengths and weaknesses of the post-net-metering models that had been proposed in their respective states. Specific responses from stakeholders within the individual states are discussed in the sections below. As we were unable to secure interviews with any electric utility representatives in Maine or state government officials in New

York, their perspectives are represented where applicable using quotes from existing secondary sources. This section concludes with a discussion of the national experts' takes on the three case study models.

Nearly all of the interview participants expressed support, albeit sometimes cautious support, for the post-net-metering models proposed in their respective states. In most cases, that support seemed to hinge on the notion that the model had achieved a fair valuation for the electricity generated by DPV systems, and thus eliminated cross-subsidization concerns. Utility representatives were generally more skeptical, either expressing concern about how the benefits of DPV would be calculated in the future, or, in the case of Minnesota, objecting to how they had been quantified in the proposed model.

#### 4.3.1. Maine

All interview participants from Maine expressed support for the proposed "Solar Standard Buyer" program. The solar industry representative noted that this captures values from DPV systems that would otherwise be left on the table under net metering. The government representative specifically endorsed two unique elements of that system, the "capacity-based step-down" for future DPV export tariffs, and the fact that the buyer (presumably an electric utility) would retain all components of the exported electricity and sell them on open markets:

*"It got the curves for the cost of solar and the price of paying pointed in the same direction. Particularly over the long term. We should be paying less and less for those resources as costs fall. So that was a big plus from our perspective"* (personal interview, ME Government).

*"We own the RECs, we own the capacity value, and we own the energy value. To the extent that there is any future ancillary services value associated with [advanced] smart inverters, we own that too. And we're going to sell that into the market... You want to make sure you capture that value for all rate payers... And that aggregation was a really important piece, because it pointed the way to where we wanted to go, to where small scale resources can actively participate in the market"* (personal interview, ME Government).

The clean energy advocate indicated tentative support, but identified a number of concerns, particularly the risk that the new approach would represent for small solar energy companies:

*"The more innovative you are, the more risky it is, because it's untested. So how do you make that leap and how do you build in enough confidence that you're not going to collapse solar markets through experimental policy? When you're talking about real small businesses with employees and jobs on the line, to say nothing of the climate crisis, where we can't afford a lot of failure, how do you deal with that?"* (personal interview, ME Advocate).

*"That was what a lot of national solar companies found objectionable, that it didn't give customers a choice of whether to do net metering of something else"* (personal interview, ME Advocate).

Another concern was the complexity of the proposed approach, which was described as an outcome of the contentious atmosphere around solar energy policy in Maine at the time:

*"The problem that we had in Maine was that people perceived that the [Public Utilities Commission] was actively hostile to building solar. I think that's been subsequently borne out. There was a lot of distrust, and so the legislation is long and complicated... In an environment where you trusted your*

*regulators to implement this in a fair and balanced way, it would have been a much simpler bill. The complexity ultimately was a liability” (personal interview, ME Government).*

While no Maine utility representatives participated in an interview for this study, the following quote from a Central Maine Power spokesperson identifies some reasons behind their support:

*“[The proposal] moves the debate into the next generation of clean energy production... and will benefit consumers more equally... I’m glad we have a chance to get beyond a backwards looking debate about a 1990’s era net metering mechanism... A lot has changed in the past 25 years in the structure of the utility industry and de-regulation, interest in renewables, and the technology itself. Net metering is a narrow mechanism that was developed in response to a minor issue. This bill moves the state, and the whole topic of solar energy and [distributed energy resources] forward for Maine” (ME Utility, via Pyper, 2016).*

Overall, the feedback from Maine suggests that a key challenge in developing a post-net-metering policy is to find the right balance, between a compensation model that is complex enough to accurately reflect the value of DPV versus one that is relatively simple to understand and less risky to implement.

#### *4.3.2. Minnesota*

The Value of Solar tariff approach is generally supported by the government and solar industry representatives who participated in this study. The government representative stated that the VOS tariff “does a more empirical job of quantifying the costs and benefits associated with delivering [solar energy],” and “eliminates the issues of cross-subsidization” (personal interview, MN Government). The solar industry representative said that the industry was generally in favor of it, arguing that “the right price signals were sent” (personal interview, MN Solar), and that such an approach will become increasingly necessary in order to mitigate utilities’ concerns about the impacts of high levels of DPV market penetration:

*“So at a high enough penetration rate, I think not only do I support value of solar, I think you have to do it. Otherwise the utility will fall into the death spiral of customers going off grid which will increase the utility’s energy rates because they have to service their same infrastructure with fewer people, which then encourages other people to go off grid if their rates went up” (personal interview, MN Solar).*

The solar industry representative also discussed how adjusting the tariff annually, according to the Consumer Price Index, was a positive feature that gave customers greater price certainty over the long term. Without that adjustment, customer-generators would see less return for their exported electricity over time, relative to retail electric rates.

The utility representative largely expressed open-mindedness with the concept of a VOS tariff, as witnessed by the utilities’ participation in the stakeholder process to develop that approach, while also expressing critiques of how some of the tariff components were calculated. This included a critique of the methodologies for avoided transmission capacity and distribution capacity costs, but the primary concerns were with the environmental value calculation:

*“The department’s methodology required us to use the social cost of carbon, which we disagreed with, as it wasn’t the same cost of carbon we use in resource planning and other regulatory filings when we’re making decisions on what resources to add to our system. [Furthermore, the cost of]*

*that component is pretty high, particularly when we could get the same environmental benefits at a lower cost through utility scale solar or wind energy” (personal interview, MN Utility).*

Both the solar industry and government stakeholders also identified the utilities’ objection to the environmental value calculation, suggesting that it is a major reason why none of the utilities in the state have adopted the VOS tariff for DPV customer-generators thus far. These results in Minnesota indicate that while all DPV stakeholders can theoretically get behind the concept of a post-net-metering model based on the different component values of DPV electricity, the concept itself is still limited by stakeholders’ disagreements about the extent of those values. This is particularly true in the case of environmental values, on which utilities and solar energy advocates can still be quite far apart.

#### 4.3.3. New York

The interview participants in New York all expressed some level of support for the new, “value-stack” Value of Distributed Energy Resources (VDER) model. They were primarily speaking with respect to the recently-released Phase One version of the VDER model, which only applies to community solar projects and larger commercial and industrial “demand-market” customer-generators. However, all of the interview participants expressed a belief that Phase Two of the VDER model would result in a similar value-stack approach for “mass-market” residential and small commercial customer-generators.

The clean energy advocate stated that the VDER would be “a more granular approach that would allow these technologies to get to scale, while still fairly valuing the energy... but without putting strain on the grid to the point that it becomes a reliability issue” (personal interview, NY Advocate). The solar industry representative characterized it as a more transparent approach that will “reimburse everybody at the same level” (personal interview, NY Solar). This participant also lauded the temporal component of the value-stack methodology:

*“One of the components... is based on the time that the power is delivered to the grid. So during peak times it’s valued a little bit higher than off-peak times, and solar is generally producing during the peak times, which is great. But that means that the meters and the billing system have to keep track of the time that each kilowatt-hour was generated and pushed out, and value it differently than one that was pushed out an hour later” (personal interview, NY Solar).*

The utility representative stated that the value-stack calculation “has some initial assumptions that might be a little bit generous, and are going to result in some revenue shifts, but overall seems to be directionally the right way to go” (personal interview, NY Utility). The utility representative also expressed support for how the VDER would differentiate electricity exports from self-consumption, which from the utility perspective “seems like a cleaner approach, which still only requires a single meter, albeit now a two channel meter to capture the ins and outs” (personal interview, NY Utility).

The utility representative also expressed some concerns, anticipating future debates with pro-solar interests about which benefits should be calculated, how cross-subsidization issues will be avoided, etc. This includes a concern about the growth of DPV while the Phase Two approach is being developed:

*“The concern with the rooftop mass-market customers is that some of the utilities that have a lot of mass market activity could still see that market get away from them before we get to January 1, 2020, and wind up with a lot of cost shifts” (personal interview, NY Utility).*

The solar energy representative expressed some concerns about how the value-stack does not account for differences in wholesale electricity prices in different parts of the state, and how it is much more complicated overall than net metering and may therefore be more difficult for utilities to implement.

No state agency representatives from New York agreed to participate in an interview for this project. However, officials from the Department of Public Service provided a staff white paper that summarized the agency's arguments that the proposed tariffs "represent the first steps in the necessary evolution of compensation for [DERs] from the mechanisms of the past to the accurate models needed to develop the modern electric system" (NY Government, via New York Department of Public Services, 2017c, p. 1). The white paper went on to argue that:

*"The VDER Phase One tariffs will provide immediate improvements in granularity in understanding and compensating for the value of DER to the electric system while setting the foundation for continual improvement. This transition will encourage the location, design, and operation of DER in a manner that maximizes benefits to the customer, the electric system, and society while also ensuring the development of clean generation... This transition will also ensure that the values and costs created by DER will be identified, monitored, and managed to ensure that all customers continue to receive safe and adequate service at just and reasonable rates, and that participation in DER markets is open to all customers, including low-income customers"* (NY Government, via New York Department of Public Services, 2017c, p. 2-3).

These results demonstrate a consensus, among the stakeholders we interviewed, that the new VDER methodology would be a fair and transparent means of compensating DPV customer-generators, and a long-term improvement over net metering. However, some of the same concerns expressed in the other states still remain, i.e., that the complexity of the new model could make it difficult to implement, and it may not fully resolve differences among stakeholders about the appropriate calculation of solar energy's component values.

#### 4.3.4. National Experts

All of the national experts identified multiple advantages of a value-of-solar type alternative to net metering, except for the one representing electric utility interests. One expert said that:

*"[This method] potentially aligns the interests of customers and utilities and society in general, and eliminates any credible argument about cost subsidies, because we've measured what it's worth and we've measured what it costs, and the value is the net of those two and that's what we should do"* (personal interview, Expert 1).

This same expert also discussed the benefit of including the Market Transition Credit (MTC) in the New York value-stack approach:

*"The MTC is supposed to act as an ease in transition. This will allow the solar market to not get shocked, as we've seen happen in Arizona, Hawaii, and other places, where they dramatically reduced a slice of the compensation overnight and watched the market collapse"* (personal interview, Expert 1).

A second national expert characterized these approaches as offering symmetry and fairness between the opportunities available to customer-generators and centralized generators:

*“If other investors are going to invest in a power plant, then [customer-generators] also should have a right to something like a long term fixed price. That’s only fair”* (personal interview, Expert 2).

The third expert offered a similar argument about the benefits of a more specific long-term contract:

*“When a customer enrolls there’s sort of a contract term, and so the customer will know from day one what they’re going to get paid for each kilowatt hour produced by their system, and that provides a long-term certainty over the revenue stream”* (personal interview, Expert 3).

The third expert went on to argue that offering long-term fixed contracts for customer generators could have the additional benefit of saving money for utilities and non-participating customers:

*“I believe that by providing a more certain revenue stream you can actually provide a lower subsidy. With net metering often times there’s an implicit risk factor that enters into the customer’s calculus. I think you could probably get away with providing a smaller incentive, and because you’re providing a firm incentive level with the value of solar tariff you might be able to generate the same level of adoption”* (personal interview, Expert 3).

The national experts who were supportive of value-of-solar approaches still identified some challenges and concerns, primarily related to the complexity of these approaches and their potential tax implications. One expert discussed how the complexity of value-of-solar approaches makes them difficult to understand, but noted that simplifying the methodology too much would make it difficult to capture the complex locational and temporal benefits of DPV. Another discussed the regulatory risk associated with the value of solar tariff, from the perspective of the solar industry or solar customers:

*“In some jurisdictions the value of solar tariff is basically administratively determined on an annual basis, and that can impose a significant administrative burden and risk on those that are dependent on that tariff for either their business, enterprise, or for their own system that they’ve installed”* (personal interview, Expert 3).

Two of the experts identified the concern that payments to customer-generators participating in VOS tariffs could be considered taxable income. One went to great length to explain that participating customer-generators receive bill credits, not “payments,” for the value of the electricity they export, and that the characterization of programs such as Minnesota’s as “buy-all, sell-all” arrangements is particularly problematic when it comes to these tax implications:

*“It’s vitally important that getting credited for production is not the same as going into the business of being a wholesale generator. The IRS and the FERC have long maintained that the only real distinction between types of generators is between generators for use and generators for sale. And merely changing the compensation rate does not turn a transaction into generation for sale. So, the value of solar tariff is not buy-all sell-all”* (personal interview, Expert 1).

The fourth national expert expressed a variety of potential concerns with value-of-solar approaches, from the perspective of electric utilities. The overarching concern was to ensure that any benefits included in VOS calculations are “identifiable and quantifiable,” not “pie in the sky” (personal interview, Expert 4). With respect to environmental values, this expert argued that those same benefits can sometimes be achieved more cheaply through other means, including utility-scale solar. Additionally, this expert expressed concerns about potential double-counting of environmental benefits, which could occur when certain environmental values are already incorporated into wholesale market prices.

## 5. Post-Net-Metering Agreements in Other States

All interview participants were also asked to discuss the pro's and con's of other alternative solar compensation models, aside from those in the three case study states. However, most of the stakeholders confessed to having little knowledge of other approaches outside their own states. The national experts were asked to comment on "value-of-solar" alternatives, writ large, and other net-metering alternatives with which they were familiar. The other states most often mentioned were Arizona, Hawaii, New Hampshire, and Massachusetts. This section provides brief summaries of the recent developments in those states with respect to net metering and DPV. Hawaii is excluded from this discussion, as its decision to replace net metering with new "self-supply" and "grid-supply" tariffs was made in a context where DPV market penetration is far higher than in any other state (Pyper, 2015).

### 5.1. Arizona

Electric utilities and solar energy supporters in Arizona have been engaged in protracted back-and-forth debates over the future of net metering since 2013. The state completed a VOS study in late 2016, after which the Arizona Corporation Commission, the state's public utility commission, issued an order to replace net metering with an avoided cost compensation rate. Solar energy supporters argued that this new approach would reduce the compensation for DPV customer-generators by about 30% (Shallenberger, 2017a). However, in March 2017, solar advocates reached a settlement with Arizona Public Service (APS), the state's largest electric utility, on a new compromise rate design. Some key details of the compromise included:

- New DPV customers would be paid \$0.129 / kWh for the electricity exported by their systems, locked-in for a period of 10 years. In subsequent years this rate for new customers would decline by no more than 10% per year. Existing customers would be grandfathered into full net metering for 20 years.
- All existing customers would remain on basic residential rates, but all new customers (including those who switch addresses within the APS service territory) would have to choose either a demand charge rate or a time-of-use rate.
- The offset rate, or the value credited to DPV customers for the energy from their systems that is consumed on site, would be \$0.105 / kWh for customers on basic residential rates, and lower for those on time-of-use or residential demand charge rates.
- Basic service charges for all residential customers would be raised from \$8 / month to a sliding scale of between \$10 / month for very small homes and \$20 / month for large homes, while those on a time-of-use or demand charge rate would pay \$13 / month.

The settlement also addressed broader issues related to solar energy in Arizona. It extended an existing program in which APS installs solar panels on the homes of low-income customers (the utility owns the panels and their generation, with the customers receiving bill credits of between \$10 and \$50 / month). The settlement also limits the ability of APS to build any new generation capacity through 2021, and new combined-cycle natural gas facilities through 2027, but with exemptions for renewable energy, distributed generation, and microgrid facilities (Randazzo, 2017a, 2017b; Shallenberger, 2017b).

Previous compromise negotiations had taken place in 2016, but did not result in an agreement. The settlement in 2017 satisfied the solar industry and APS, both of which signaled their intent to stand by it through at least the end of 2018, but was not supported by energy efficiency advocates and some of the

other parties that had intervened in the rate case. Interestingly, a representative from national solar company Sunrun offered only limited praise for the settlement, saying that it would allow solar installers to remain in the Arizona market, but was not ideal and should not be used as a model for other states (Shallenberger 2017a, 2017e)

## 5.2. Massachusetts

In August, 2017, the Massachusetts Department of Energy Resources (DOER) filed its proposed final version of the Solar Massachusetts Renewable Target (SMART) Program. This program is the result of a rule-making process initiated by a compromise solar energy bill, signed in April, 2016. That bill also raised the state's net-metering cap from 4% to 7% of a distribution company's peak load for private-sector projects, with systems below 10 kW exempt from the capacity limit (Schoenberg, 2016; Database of State Incentives for Renewables and Efficiency, 2017a). The DOER developed the program details via a comprehensive stakeholder process that included nearly 40 working group meetings, plus additional outreach to affected stakeholders, with over 100 different stakeholder representatives participating and over 600 pages of comments received (Massachusetts Department of Energy Resources, 2017).

The SMART program would replace the current arrangement – in which distributed customer-generators participate in net metering and can also sell solar renewable energy credits (SRECs) at variable market rates – with a system that combines both forms of compensation into a single long-term fixed-price contract. This fixed-contract price would vary based on a number of factors, including project capacity (with higher rates for smaller projects, up to a 5 MW maximum). Additional rate “adders” would be applied to projects that met certain criteria, such as being constructed on a brownfield (an extra \$0.03/kWh) or for a low-income property owner (also \$0.03/kWh). The rates would decline as each “block” of program capacity (approximately 200 MW) is filled, and 20% of the capacity within each block would be reserved for projects smaller than 25 kW (Farrel, 2017).

## 5.3. New Hampshire

In June, 2017, the New Hampshire PUC issued order No. 26.029, which put in place temporary new DPV tariffs that will be replaced upon the completion of a new DER valuation study. The new temporary tariffs represent a compromise between the solar industry and utilities, forged through a process that began in 2016 when the state legislature directed the PUC to develop an alternative to net metering. Utilities and the solar industry filed separate settlement proposals in March, 2017, and the ensuing PUC order blended the two proposals, drawing from common elements of each (Walton, 2017e; Shallenberger, 2017d). The new temporary tariff will apply to all renewable energy systems with a capacity of 100 kW or less, and is structured as follows:

*“Customer generators will receive monthly excess export credits equal to the value of kWh charges for energy service and transmission service at 100 percent and distribution service at 25 percent, while paying non-bypassable charges, such as the system benefits charge, stranded cost recovery charge, other similar surcharges, and the state electricity consumption tax, on the full amount of their electricity imports” (New Hampshire Public Utilities Commission, 2017, p. 2).*

Existing systems, including those submitted for utility interconnection over the course of the forthcoming DER study, will be grandfathered into the existing net-metering rate structure through the end of 2040. The PUC order declined to set any limits on the amount of generating capacity that could

be installed under the tariff, as neither the solar industry nor the utilities had identified a need for such a limit in their proposals (New Hampshire Public Utilities Commission, 2017).

The PUC order also included some insight into the benefits of having both sides involved in the DPV rate-making process, and the need for continued collaboration to address remaining issues:

*“Those who assumed large cross-subsidies in favor of DG customers and those who assumed large quantifiable benefits of DG were challenged by each other and, in the end, almost all of the participants joined compromise settlement proposals that are more alike than they are different. They also agreed on the need to develop more extensive and detailed data, and to engage in a number of pilot or test programs”* (New Hampshire Public Utilities Commission, 2017, p. 73).

Several of the interview participants for this study mentioned the New Hampshire process as an interesting example of collaborative rate-making for DPV. One solar industry representative described it as a moderately successful process, as it “is basically making incremental changes to net metering, but recognizes that net metering is not forever, and moves to a net metering successor in a thoughtful, deliberate, incremental way” (personal interview, ME Solar).

#### 5.4. Other Recent Developments

A few other examples of recent solar energy compromise efforts bear mentioning. In Utah, the state’s largest electric utility, Rocky Mountain Power, has settled with the solar energy industry and other stakeholders on a compromise approach to DPV compensation. Under this agreement, existing net-metering customers will be grandfathered in at the full retail rate through the end of 2035. New customers will be compensated at \$0.092/kWh, about one cent below the average residential rate. This rate will be in place over the course of a three-year transition period, during which time a new rate will be developed via a VOS study process by the state’s Public Service Commission (Walton, 2017f).

In Nevada, Assembly Bill 405 was adopted in June, 2017 with input from a variety of groups, including electric utilities and major solar energy companies (Gonzalez, 2017a; Gonzalez, 2017b). As noted in Section 1 of this report, the bill restored net metering at 95% the retail rate, with future step-downs once certain capacity targets are met. It also established a “Renewable Energy Bill of Rights” that affirms residents’ rights to generate, consume, export, and store renewable energy, be interconnected with the grid, receive “fair credit for any energy exported to the grid,” and have that energy “given priority in planning and acquisition of energy resource” by electric utilities. This Bill of Rights also includes various consumer protections and requires that net-metering customers remain within the rate class to which they would belong if they did not participate in net metering, without any fees or charges that are different from those assessed to other customers in their rate class. Finally, the legislation also allows electric utilities to file requests to establish time variant rate schedules intended to “expand and accelerate the development and use of energy storage systems” (Brooks, *et al.*, 2017, p. 17-18).

In North Carolina, a major solar energy compromise bill was adopted in the summer of 2017, but it primarily addressed larger-scale solar energy systems rather than DPV. The legislation did not change the state’s net-metering policy, other than to say that utilities must complete a cost-benefit study before issuing any filings to alter net metering (Trabish, 2017a, 2017b).

Finally, a recent effort to find consensus on net-metering policy in Arkansas has failed, as a working group set up by the state’s Public Service Commission was not able to establish a compromise approach that satisfied both utilities and solar energy advocates (Walton, 2017a).

## 6. Broader Opportunities, Challenges, and Long-Term Issues

All interview participants were asked to comment on broader, long-term opportunities, challenges, and issues related to the role of DPV in an evolving electricity landscape. While the responses were wide-ranging, a few common themes emerged around reforming retail electric rates, incorporating smart grid, demand response, and energy storage technologies, and identifying a proper role for utilities within the changing electricity landscape.

### 6.1. Rate Reform for all Customers

The need to reform electricity rates for all utility customers was the most commonly cited long-term issue, identified by representatives of all stakeholder groups and two of the four national experts. These responses largely reinforced and expanded upon previous statements, discussed in Section 4.1 of this report, about the need for smarter, more granular mechanisms of compensating DPV owners that accurately reflect the costs associated with providing electricity. They are also consistent with some of the criticisms that stakeholders made of net metering, i.e., that is rooted in a flat retail rate structure that does not take into account locational and temporal values of electricity and does not properly incentivize energy storage or other new technologies (see Section 4.2).

The need for rate reform has been addressed in several prominent national studies, such as the “Utility of the Future” report by the Massachusetts Institute of Technology (MIT) Energy Initiative, which argues that the only way to “achieve efficient operation and planning in the power system is to dramatically improve prices and regulated charges (i.e., tariffs or rates) for electricity services” (Pérez-Arriaga & Knittel, 2016, p. IX). Specific rate reform suggestions from the MIT study include:

*“Flat, volumetric tariffs are no longer adequate for today’s power systems and are already responsible for inefficient investment, consumption, and operational decisions... Peak-coincident capacity charges that reflect users’ contributions to incremental network costs incurred to meet peak demand and injection, as well as scarcity-coincident generating capacity charges, can unlock flexible demand and distributed resources and enable significant cost savings” (Pérez-Arriaga & Knittel, 2016, p. X).*

A 2016 study by the U.S. Department of Energy also noted the need for better rate structures to ease the integration of DPV into electrical distribution systems:

*“[S]torage and other complementary technologies that can ease integration of very high penetration [DPV] may only see widespread adoption if economic signals compensate customers based on time- and location-varying grid conditions and market prices. Hence, advanced tariff designs that provide appropriate price signals to customers would provide an economic foundation for effective integration of very high penetrations of [DPV]” (Palmintier, et al., 2016, p. 42).*

Both the Edison Electric Institute (EEI) and the Solar Energy Industries Association (SEIA) have identified the need to update utility rate structures. The SEIA (2017) suggests that retail rates can be redesigned in a way that rewards utilities for encouraging conservation and distributed generation, while sending price signals – such as through time-of-use rates and commercial-sector demand charges – that more accurately reflect the supply and demand costs of electricity. Likewise, EEI (2012) has argued that there is “an urgent need to update retail rates” in order to “integrate DER into the electric system while

ensuring reliability, safety, and fairness for all customers” (Ackerman & De Martini, 2012, p. 9). A couple of interview participants representing electric utility interests expressed similar sentiments:

*“I think we want to look at really holistic rate reform to ensure that we’ve got a level playing field for all those resources and are not picking one technology over another as they can provide various grid services or grid resources. So I think getting that rate reform and getting that rate structure both fair and correct is probably going to be the most important issue moving forward”* (personal interview, Expert 4).

*“Long term, utilities probably need to rethink the use of volumetric rates for mass market customers, because net metering in and of itself is not a problem if you have demand charges or a larger customer charge to collect some of your revenue requirement”* (personal interview, MN Utility).

A couple of solar energy supporting stakeholders discussed how better electric rate structures can help encourage the adoption of other DER technologies, including energy efficiency and storage:

*“We have to have much more sophisticated pricing mechanisms that recognize the attributes of different resources, the time of day that they are producing, and how they match load, and that have two way directionality. So we’ve got to figure out how to pay people for not doing stuff”* (personal interview, ME Advocate).

*“I think it is impossible to deal with distributed solar as a standalone question. My feeling is not even over the long term, but over the medium term, we need to move to a more sophisticated rate design for all customers, including for DER customers, that provides actionable price signals that help people modify their behavior in a way that benefits all customers. Right now I have absolutely no incentive to not charge my car on a hot summer afternoon, even though it’s very expensive for rate payers as a whole to do that, and I frankly could care less whether I charge in the afternoon or if I charge at night. Right now I have zero incentive to wait an hour to plug in my car when I get home on a summer afternoon, and that’s a market failure”* (personal interview, ME Solar).

However, a couple of stakeholders expressed concerns about the efficacy of these proposed new rate structures, including one who indicated skepticism about how they would be designed:

*“Most people I talk to think that the future looks like time of use rates of one sort or another... I’m sort of wary of this because I think these are artificial price signals, and they will be negotiated time of use rates rather than anything that’s even close to being market-based. Whether they make sense for customers at all will depend on whether solar advocates or utility advocates have the upper hand at the PUC. So it’s tough to get a time of use rate where someone doesn’t have their thumb on the scale one way or another”* (personal interview, ME Government).

Finally, a couple of interview participants described the challenges of implementing new rate structures in a way that is readily accepted and easily adoptable by customers:

*“You know energy pricing is changing basically every five minutes, and yet from a consumer standpoint you’re insulated from that. That raises a lot of other questions in terms of customer acceptance and behavioral change”* (personal interview, ME Utility).

*“Perceptions or risk are probably the biggest challenge. Especially when it comes to more dynamic forms of electricity pricing... It’s just asking a lot more of customers than what they’re used to in terms of understanding the patterns of their own electricity consumption. Ultimately what will help surmount those challenges is just the introduction of technology and service providers that basically do that for customers, but it’s sort of a chicken and egg issue where those technologies and services aren’t going to really develop unless there’s a demand. So it’s just a little bit hard for regulators to figure out how to stage the introduction of more complex rate structures. You want to commit to doing it so that you’re providing a signal to the industry that there’s going to be a need to help customers manage their electricity usage, but do it at a pace that allows those technologies and services to evolve and enter the market in time to help customers transition”* (personal interview, Expert 3).

These questions about implementation and customer transition would likely be even more pressing for utilities that consider some of the latest rate structure innovations, such as dynamic pricing, real-time pricing, critical peak pricing, and peak-time rebates (Faruqui, Hledik & Sergici, 2009).

## 6.2. Incorporating Energy Storage, Demand Response, and Smart Grid Technology

Numerous studies have shown that improved energy storage technologies could dramatically improve the value of DPV and help to address many of the concerns about integrating large amounts of solar energy into the grid, such as by allowing excess solar energy generated during daytime hours to be released during evening peak demand periods (e.g., GTM Research, 2014; National Renewable Energy Laboratory, 2014; Palmintier, *et al.*, 2016). For example, a study by Navigant Consulting (2016) for Dominion found that “emerging technologies can enable greater amounts of solar capacity (i.e., hosting capacity) on many [Dominion] feeders,” and that energy storage can be “very effective in mitigating solar impacts, when installed in capacities equal to about 10% of installed solar capacity” (p. 42).

Improvements in energy storage and inverter technology could also strengthen grid reliability, as they would allow DPV to play a greater role as a back-up power source during outages (National Renewable Energy Laboratory, 2014). Energy storage can also provide ancillary grid services such as frequency regulation and response, voltage support, load ramping support, black-start capability, and spinning reserves (Akhil, *et al.*, 2017).

Several interview participants identified energy storage as a highly-important long-term consideration for the future of the electricity grid, with one national expert in particular emphasizing its long-term potential to disrupt utility markets:

*“I think the availability of storage that is cost effective is going to be of the utmost importance, and will make massive changes... I think that this industry is about to be overwhelmed by all of the possibilities for moving individual loads or groups of loads off of regular tariffs and on to some combination of solar and batteries instead of AC electric power delivered by a centralized utility”* (personal interview, Expert 2).

Other interview participants emphasized the implications of energy storage for net-metering and post-net-metering policies:

*“Definitely storage is a big issue. Net metering is essentially just an accounting proxy for storage. So once low cost storage becomes widely available, it kind of makes net metering moot, and reforms to net metering moot”* (personal interview, Expert 3).

*“If you’re going to build a platform for distributed generation going forward, it needs to work both for distributed solar and for storage, or at least have a pathway to work for storage”* (personal interview, ME Government).

*“Storage also allows you to enhance the values of solar... If you move to a value of solar model, [with higher payments for peak generation], then it becomes a more lucrative thing”* (personal interview, MN Solar).

A couple of stakeholders also mentioned the importance of demand response and smart grid technologies for the integration of DPV into the electricity system. Demand response can be defined as “changes in the electric load – such as reductions, increases, or shifts – by end-use customers from their normal consumption patterns in response to specific market or system conditions” (Smart Electric Power Alliance, 2017, p. 5). This can include existing technologies such as allowing utilities to remotely cycle off customer water heaters during high demand periods, as well as emerging concepts such as vehicle-to-grid energy storage. Such approaches can have the advantage of shifting customer loads to times when solar resources are more abundant, thus allowing solar PV generation to more effectively reduce peak demand (Wu, Tazvinga, & Xia, 2015). One interview participant discussed the potential scale of demand response, and the level of complexity that would add to grid management decisions:

*“We may potentially have millions and millions of people in demand response. So they’re using electricity when we want them to and not when we don’t. And then you add in the fact that they could be storing it and generating it, and you have a really complicated new system that’s needed, and that’s big project”* (personal interview, ME advocate).

In addition, emerging smart-grid technologies can allow electric utilities to better utilize DPV and other distributed generation sources, while increasing efficiency, reducing peak demand, and enhancing grid security. Some examples of smart-grid advancements include enhanced two-way communication between the utility and consumers, and increased computerization, automation, controls, and sensors to help respond to changing electricity demand (U.S. Department of Energy, 2016). The importance of smart grid technologies to DPV is captured in the following quote from the interviews:

*“One of the key aspects as we look at moving towards this distributed energy future is developing and building a smarter energy infrastructure... that will allow both utilities and third party providers to better assess the value of distributed energy resources”* (personal interview, Expert 4).

Smart grids can also allow consumers to have greater control over their energy usage, such as by monitoring and controlling their real-time energy consumption via smartphone- or computer-based energy management tools. These technology advances will have important implications for electric utilities, as discussed, in the following section.

### 6.3. Moving Electric Utilities to the “Distributed System Platform” Model

The growth of solar energy and other distributed energy resources, along with advances in smart grid technology and energy storage, naturally raises questions about the role of utilities in the evolving electricity landscape. One emerging concept is that utilities should evolve to a “distributed system platform” model. In this model, utilities’ role as the provider of centralized generation capacity would be diminished, and replaced with a new set of responsibilities for coordinating multiple streams of distributed generation, demand response, energy storage and release, etc. This would of course require a new form of utility regulation that allows utilities to take on those responsibilities and generate

revenue from them. As described by one of our national expert interview participants, such a model would be a dramatic change from the current utility business model:

*"I really can't see any viable path except for moving toward platform utility models where we try to get the distribution utility to act as an impartial platform and provider of hosting services... I think there's a way to do it even in the monopoly state, but we have to remove the utility's incentive for throughput and capital investment and give them a different way to make money" (personal interview, Expert 1).*

A group called "America's Power Plan" has released a series of reports that explore possible utility roles and regulatory approaches in a new distributed electricity paradigm. One study modeled how utilities could respond to different types of distributed energy challenges under three regulatory models: the existing "cost of service" model, a "performance incentive mechanisms" approach in which "regulators offer a financial upside or downside to utilities for performance against targeted outcomes via cash payments or incentive rates of return," and a "revenue cap" model in which "regulators establish a benchmark for what an efficient level of utility expenditures would be and tie utility revenue to the achievement of that benchmark" (Aas & O'Boyle, 2016, p. 3). In every scenario, they found that the cost-of-service approach "creates utility incentives that are misaligned with societal value" while the other approaches would properly incentivize utilities to achieve better societal outcomes (p. 5).

Another America's Power Plan report described three potential roles that utilities could play in a distributed energy system. In one extreme they would play a minimal "wires only" role, while at the other extreme they would maintain a vertically integrated monopoly role as "energy services utilities." In between, they could play a "smart integrator" or "orchestrator" role, in which utilities would "[form] partnerships with innovative firms to coordinate and integrate energy services" (Lehr, 2013, p. 2). The report further describes this integrator role as follows:

*"In this model, the utility role is one of facilitating technology and service changes but not necessarily providing all of them... Utilities would maintain their strong engineering and reliability standards, but adapt and apply them to new technologies and service offerings. New standards and changes to existing standards would be needed to incorporate new equipment, simplify and rationalize interconnections between new equipment and utility distribution and transmission grids and integrate new generation into utility operations and markets" (Lehr, 2013, p. 16).*

The America's Power Plan reports recognize the need for regulators to provide utilities with "the right incentives to move towards a renewable energy future" and to "structure public interest goals into regulation" in a way that allows new utility business models to succeed (Lehr, 2013, p. 31).

The MIT Utility of the Future study provides additional detail on how utility regulation could allow these new distribution utility business models to develop. This includes creating financial incentives for operational expenditures that are equal to those related to capital investment, which would allow utilities to "pursue cost-effective combinations of conventional investments and novel operational expenditures (including payments to distributed resources)." In addition, they recommend outcome-based performance incentives related to the quality of service in areas "such as enhanced resiliency, reduced distribution losses, and improved interconnection times." Finally, they cite the need for long-term innovation incentives that will support research and demonstration projects, so that utilities can "[learn] about the capabilities of novel technologies and practices that may have higher risk or longer-term payback periods" (Pérez-Arriaga & Knittel, 2016, p. X).

Such transitions would not be easy, of course. The national expert interview participant who represents public utility commissions spoke at length about the challenges that the new electricity landscape poses for utilities, how those broader issues could be informing their resistance to DPV, and the need for utilities to adapt to these changing circumstances:

*“The utilities are being pushed by a lot of factors, and a lot of them are very threatening to the previous utility business model. But the only one that they seem to think they have an opportunity to do something about in the very short run is changing the way that we compensate distributed generation, which by and large now means distributed solar. So they are going against the one thing that they think they know how to attack, when really it’s just a little side issue compared to the totality of change that’s going to come into that industry in the coming years”* (personal interview, Expert 2).

*“Utilities are either going to have to come to grips with the idea that they’re going to be shrunken one end use at a time, one load at a time until they’re just a shadow of what they are today. Or they’re going to have to reinvent themselves so they have a role in those changes”* (personal interview, Expert 2).

Conversely, one of the stakeholder participants from Maine argued that fundamental changes to the utility system will not be needed, given that there are limits on the maximum feasible market penetration of DPV:

*“I don’t think that ultimately more than 20% of residential customers [will ever] install rooftop solar... Even in Massachusetts where they have a ridiculous subsidy system, where the payback period is like 3 years or something like that, there’s a limit to how far [DPV market penetration] will go. So I don’t think that distributed generation – rooftop solar in particular – presents a fundamental challenge that will require a reevaluation of the whole utility business model. I think that’s just a lot of bunk. I don’t think it requires fundamental changes even at [a 20% penetration] level. You start to have policy concerns about who’s paying for what and who is not at that point, but I don’t think you need to redesign the utilities on the basis of that”* (personal interview, ME Government).

This stakeholder was also skeptical of the extent to which electricity customers would want to actively engage in the types of load management activities envisioned in many future distribution utility concepts:

*“I think that most customers just want to turn the lights on, and they want a predictable power bill month to month. So the story that we’re telling about ‘prosumers’ and redesigning the grid and all sorts of very costly investments to help enable these prosumers is a problematic one... because you’re basically going to charge the bulk of customers a lot of money for services that are only going to be used by a subset of customers”* (personal interview, ME Government).

This discussion of the potential need for broader changes to the electricity landscape reinforces the overall point of this section of our report, which is that decisions about post-net-metering compensation models for DPV cannot be made in a vacuum. Rather, these decisions must recognize that the flaws in net metering are outcomes of the overarching flaws in our retail electricity rate structures. Furthermore, while debates may continue to rage about the true market value of the electricity produced by DPV systems, all stakeholders should recognize the need for DPV policies that are compatible with the broader deployment of smart grids, demand response, and energy storage.

## 7. Discussion and Conclusions

The goal of this study was to explore the issues that arise with the growth of DPV and DER resources, particularly the question of how DPV customer-generators should be compensated for the electricity that they provide to the grid, and to identify models from other states that could be more appropriate over the long term than current net-metering approaches. We evaluated three case studies in which electric utilities, the solar energy industry, and other affected stakeholders had worked together to develop a compromise solution for a new compensation model that could replace net metering. This section summarizes some of the key findings from our research and discusses the implications of those findings for Virginia and other states that are grappling with questions about the future role of DPV for utilities, ratepayers, and the grid as a whole.

We begin by exploring the notion of cross-subsidization, or the question of whether or not DPV customers impose costs upon the grid that lead to electricity rate increases borne by all customers. We demonstrate that any actual cross-subsidization is likely very minimal in the short term, but such concerns could arise in the future if DPV capacity reaches the levels that many solar energy supporters desire. We then argue that, while net metering remains a useful tool for supporting DPV growth in the short to medium-term, it is not a viable long-term solution for the future distributed energy landscape. This illustrates the need for post-net-metering models that are appropriate for a distributed energy future while still fairly compensating DPV customer-generators and satisfying utility concerns. We then identify some of the key characteristics of an ideal post-net-metering model, and discuss some of the important questions that would have to be addressed in the development of such a model.

### 7.1. The Value of Solar and the Potential for Cross-Subsidization

Questions about the efficacy of net metering and the potential need for replacement compensation models must be considered with respect to both short-term and long-term conditions. This is particularly true when we consider the question of cross-subsidization, or the extent to which DPV customer-generators may or may not be subsidized by other electric utility customers who do not own DPV systems. These claims rest on the assumption that the value of electricity that DPV systems export to the grid is worth less than the retail rate. It is outside the scope of this study to thoroughly research the value-of-solar (VOS) issue, but looking at the results of some recent VOS meta-studies can be helpful in framing the broader net-metering debate.

A report by Environment America compared eleven VOS studies completed between 2013 and 2015, including studies completed on behalf of electric utilities, the solar energy industry, and PUC's. The two studies completed on behalf of investor-owned utilities produced VOS totals that were substantially below the applicable retail rate, while the one study completed for a municipal electric utility produced a VOS slightly above the retail rate. The six studies commissioned by non-utility organizations (mostly the solar industry or pro-solar non-profits) produced VOS values above retail rates, as did both of the studies commissioned for PUC's. In three cases – two non-utility studies and one PUC study – the VOS was found to be more than double the retail electric rate (Hallock & Sargent, 2015).

Another recent report, by Lawrence Berkeley National Laboratory (LBNL), evaluated 19 VOS studies completed from 2012-2016. The LBNL report broke each study's VOS total into its component pieces, which allowed it to isolate and compare the studies' results for "core" VOS values such as avoided energy costs and generation / transmission / distribution investments, versus "core+" values such as reduced fuel price risk and the cost of environmental compliance. Importantly, the LBNL report removed

values for broader societal benefits, where applicable, from those studies that had included them (Barbose, 2017).

The LBNL analysis identified similar patterns of results to those from the Environment America report. While the LBNL did not identify the sponsors of the individual studies included in its analysis, this information is easily obtained by cross-referencing with the Environment America report and reviewing the original versions of the remaining studies. All of the utility-sponsored studies had VOS scores that were less than the applicable retail rates, with the exception of the same municipal utility study. The studies sponsored by PUCs or pro-solar groups mostly found the VOS to be either close to or above the retail rate, with several showing results well above 150% of the retail rate.

Unlike any other VOS report or study, the LBNL developed a formula to estimate the effect of DPV use on retail electricity rates, based on the ratio of the value of solar to the retail rate and the market penetration of DPV in that area (i.e., the percentage of a utility's customers that have DPV systems). According to this formula, a state with full net metering and a VOS equal to 75% the retail rate would see a rate increase of 0.25% for every one percent of DPV market penetration. Conversely, if the VOS were 125% of the retail rate, then rates would decrease by 0.25% for every one percent of customers who install DPV. Under this rather wide range of possible VOS values, increasing DPV market penetration to 5% would still impact rates by little more than 1% in either direction. To put that in perspective, only a handful of utilities in the country, mostly in Hawaii, have DPV market penetrations of 5% or more, and the nation-wide average is about 0.4% (Barbose, 2017).

The purpose of reviewing these VOS meta-analysis here is to illustrate that any potential cross-subsidization is likely very minimal in any utility service area that has a low DPV market penetration. While no complete VOS analysis has been conducted for Virginia, this conclusion is supported by a partial VOS study completed in 2011 by the Virginia State Corporation Commission. That study concluded that increasing DPV penetration to the full 1% aggregate net-metering cap would cost the equivalent of \$6.73 per residential customer per year, or a bill increase of "less than one-half of one percent" (Virginia State Corporation Commission, 2011, 2012, p. 10-11).

That being said, many solar energy supporters envision a future in which DPV market penetration is well above 5%. In that scenario, if the true VOS is determined to be less than the retail electric rate, cross-subsidization could be much greater. For example, the LBNL formula suggests that the VOS is equal to 75% of the retail rate, then a 20% DPV market penetration would result in a 5% rate increase. If the VOS is equal to only half of the retail rate, as is found in some of the utility-sponsored studies, then a 20% market penetration would raise rates by 10% per the LBNL formula.

However, the debate about VOS values and the hypothetical extent of cross-subsidization may be unnecessary, as there are plenty of other reasons to question the long-term utility of net metering as the means of compensating customer-generators for their contributions to the grid.

## 7.2. Long-Term Limitations of Net Metering in a Distributed Electrical Grid

Many of the stakeholders who participated in our research interviews agreed that net metering is a simple and effective means of stimulating and supporting a nascent DPV market. However, virtually all also agreed that it has clear limitations as a long-term solution, particularly in the context of a changing electricity landscape in which solar energy and other DERs become both prevalent and essential. These criticisms boil down to two essential, related points: net metering is rooted in a fundamentally flawed

flat-volumetric retail pricing scheme, and it actively discourages energy storage and other load-shifting behaviors that are needed to maximize solar energy's overall contributions to the grid.

Multiple interview participants commented on how net metering is an inaccurate representation of the value of electricity from DPV systems, and how it should be replaced with a more granular system that takes into account the locational and temporal dimensions of that value. Comments to this effect were made by individuals from each of the four stakeholder groups (utilities, solar industry, solar advocates, and government officials), and all four national experts.

Furthermore, one stakeholder pointed out that while net-metering rates do not vary according to any measure of the value of solar, they do vary based on the rather arbitrary factor of the type of customer occupying the building on which DPV systems are placed – the energy produced by residential-sector customer-generators is valued at the residential retail rate, while that produced by commercial-sector customer-generators is valued at the commercial retail rate. As commercial retail rates are often lower on a per-kWh basis (not accounting for demand charges), this is arguably an inversion of the actual value of solar produced by commercial vs. residential-based DPV systems. Daily energy demand curves in many commercial-sector businesses (e.g. office buildings) peak in the mid-day, roughly concurrent with the peak of solar energy production, whereas residential demand tends to peak in the early evenings (OpenEI.org, 2013). This means that a greater percentage of the production from commercial-based DPV systems can be consumed on-site, mitigating concerns about reverse power flows and other potential technical impacts from DPV over-generation (Keyes & Rábago, 2013). Therefore, a net-metering scheme that values solar energy produced in the residential sector over that produced in the commercial sector presents a perverse disincentive to the placement of DPV systems in locations where they would provide greater value.

Interview participants also discussed how net metering discourages behaviors that would increase the value of DPV and enhance the integration of DPV and other DER's into a more advanced and sustainable distributed electricity network. Multiple stakeholders, including solar energy supporters, noted how net metering discourages customers from investing in energy storage and/or taking other steps to shift their net loads away from peak-demand periods. This is particularly true in the residential sector, where the prevalence of flat volumetric rates, without time-of-use adjustments or demand-charges, discourages all customers from adjusting their loads in a way that reflects the actual price of producing electricity at different times.

Net metering also discourages the installation of west-facing DPV systems that would reach their peak production later in the afternoon, closer to high-value peak demand times. Finally, DPV systems can have greater value if they are placed at specific locations on distribution feeders where the potential for negative distribution grid impacts is lower and/or ancillary services benefits are higher. Again, the flat volumetric nature of net metering does not capture those benefits or incentivize the placement of DPV systems in locations where those benefits are greater.

### 7.3. Factors to Consider in Developing Post-Net-Metering Models

The research findings presented in this report indicate that an ideal post-net-metering DPV compensation model should have the following key characteristics:

- Offer a tariff for DPV exports that is based on the sum of solar energy's component values, as determined in an independent VOS analysis for the given state or utility service area.

- Include in the DPV export tariff a means of accounting for temporal values (i.e., the time of day at which exports occur, relative to peak demand), and if possible, locational values (i.e., the unique benefits or challenges that DPV systems provide due to their position on their respective distribution feeders).
- Develop the new DPV tariff as part of a larger overhaul of utility rate structures that more accurately reflects the costs of providing electricity, sends the proper price signals to both DPV and non-DPV customers, and encourages the proliferation of DPV and other DER's including demand response, energy storage, and smart grid technology.

A number of questions would arise in the process of developing a new post-net-metering model. In addressing these questions, policymakers would have to consider the relative benefits of a model that reflects the value of DPV electricity exports as accurately as possible versus one that is, relatively speaking, easier for customers to understand and for utilities to implement.

- For how long will existing DPV customers be grandfathered in to net metering? At what point will new customers be enrolled in the post-net-metering model, and how will that transition take place?
- Would the new post-net-metering tariff apply to DPV exports only, or also to self-consumption (i.e., the electricity from DPV systems that is consumed on site)? Would it apply equally across a state or utility service area, or would it calculate the unique locational value of each system?
- What happens if the initial valuation of DPV exports produces a number that is substantially lower or higher than current retail rates? Will the post-net-metering policy ensure that new customer-generators are compensated at no less than the retail rate for a period of time, as has been the case in Minnesota and New York?
- How would the new compensation rate change in the future? Would the rate for new customers be reduced as certain capacity thresholds are met, as was proposed in Maine, or would it be re-calculated annually, as is proposed in New York and Minnesota? Once a customer is enrolled in the post-net-metering program, would that customer's compensation increase over time with inflation, as proposed in Minnesota, be re-calculated on a regular basis, or remain the same for a fixed contract length?

The most critical aspect of any post-net-metering compensation model is the recognition that the true value of electricity exported from DPV systems is not simply a function of the retail rate that the applicable customer-generator pays for electricity. Rather, it is the sum of many component VOS values, which can vary considerably based on broader electricity market conditions, state-level policy considerations, and the time and place in which the electricity in question is delivered to the grid.

In calculating a post-net-metering DPV tariff, much of the debate is likely to center on the valuation of environmental benefits, such as whether to include the cost of complying with existing environmental regulations and/or using a "social cost of carbon" metric for the value of avoided greenhouse gas emissions. Much of the debate around the value of solar energy, and the extent to which it should be supported through public policy, boils down to the fundamental question of whether or not we attach an economic value to the mitigation of climate change and other environmental impacts. This has been a major point of disagreement in past solar energy debates, including the development of the Minnesota value-of-solar tariff. Perhaps the greatest weakness of post-net-metering models is that they do not present a ready solution to this problem.

Recognition of locational and temporal values is particularly important if a post-net-metering tariff is to stimulate the investments in DPV and other DERs that will be most beneficial and effective in the evolving distributed electricity landscape. However, those will also be the most difficult aspects to implement, as they will require the use of advanced meters that can measure two-way electricity flows and mechanisms for identifying the locations on distribution feeders where DPV can provide the greatest value. Utilities can address this latter challenge by working with urban planners to create Geographic Information Systems (GIS) models that map the location of distribution feeders in a given area, estimate energy demand curves and DPV production potential for every building on each feeder, and identify the potential of those feeders to absorb additional DPV capacity (Pitt, *et al.*, 2017).

A key issue, as has been discussed throughout this report, is that any new post-net-metering compensation model should be developed as part of a broader process to build a more resilient and sustainable distributed electricity system. This includes reforming electricity rates for all customers in order to more accurately reflect the cost of electricity service and encourage load-shifting behavior. It also includes developing policies that support demand response and the expansion of smart grid and energy storage technologies. Finally, it also includes establishing mechanisms to compensate utilities for investing in distributed grid infrastructure and providing distributed system platform services.

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## Appendix A: Research Interview Questions

### Questions for Solar Energy Stakeholders in Case Study States

1. What are the key outcomes that you feel should be accomplished through the regulation of distributed solar PV, and what are the most important factors that must be taken into account to ensure that those outcomes are achieved?
2. What do you consider to be the primary benefits of Net Metering to regulating distributed solar PV systems and compensating system owners for the energy they provide to the grid?
3. What do you consider to be the primary weaknesses or challenges of Net Metering to regulating distributed solar PV systems and compensating system owners for the energy provided to the grid?
4. Please briefly describe your state's proposed major change to regulating distributed solar PV and compensating system owners, and explain why you do or do not support that change.
5. Do you consider your state's proposed new approach to regulating distributed solar PV systems to be viable in the short to medium term? Why or why not?
6. Are you aware of any new or proposed new approaches from other states that are notably different from how your state regulates distributed solar PV systems? If so, please briefly describe those other approaches and discuss your perceptions of their strengths and weaknesses.
7. In the long-term, what changes do you believe should happen to the regulation of distributed solar PV systems, and/or to the electricity generation and distribution system as a whole?
8. Do you have any final thoughts to share related to any of the topics we have discussed today?

### Questions for National Solar Energy Policy Experts

1. What are the key outcomes that you feel should be accomplished through the regulation of distributed solar PV, and what are the most important factors that must be taken into account to ensure that those outcomes are achieved?
2. What do you consider to be the primary benefits and weaknesses of net metering as a means of compensating distributed solar PV system owners for the energy they provide to the grid?
3. What do you consider to be the primary benefits and weaknesses of "value of solar" tariffs as a means of compensating distributed solar PV system owners for the energy they provide to the grid?
4. Are you aware of any other approaches, existing or proposed, to compensating distributed solar PV system owners for the energy they provide to the grid? If so, please briefly describe those other approaches and discuss your perceptions of their strengths and weaknesses.
5. What are the most important emerging trends or factors that will influence how states regulate distributed solar PV and compensate system owners?
6. In the long-term, what changes do you believe should happen to the regulation of distributed solar PV systems, and/or to the electricity generation and distribution system as a whole?
7. What do you consider to be the major challenges to implementing the changes you described?
8. Do you have any final thoughts to share related to any of the topics we have discussed today?