

Optimizing the Grid Integration of Distributed Solar Energy

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Executive Summary

Solar energy is the fastest-growing source of energy in the United States, and the cost of installing solar photovoltaic (PV) systems has dropped rapidly over the past 10 years. While solar energy only provides about 2% of our total national electricity supply currently, studies by the U.S. Department of Energy (DOE) and other sources indicate that it could provide much higher percentages over the coming decades. However, solar energy has come under scrutiny, from opponents who contend that it raises rates for electricity customers and disrupts electrical grid operations. Supporters counter that, in addition to the obvious environmental benefits, solar energy can help electric utilities save money on conventional generation fuels, avoid new generation capacity investments, and enhance the transmission and distribution grids.

Much of this controversy is focused on smaller-scale, “distributed” solar photovoltaic (DPV) energy systems, particularly when they are connected to the local electricity grid via “net-metering.” Under this arrangement, DPV owners can return any excess electricity that their systems generate to the distribution grid, in return for a credit from their utility provider equal to the retail electricity rate per kilowatt-hour (kWh). Concerns about the impacts of DPV on electricity operations have led some states to levy fees on system owners, or to pass laws that restrict or eliminate net-metering.

This research project addresses a number of DPV grid integration technology and policy issues, with a particular emphasis on Virginia. Our research involved the following tasks:

1. A comprehensive review of current research on two contentious aspects of the solar energy debate: “value of solar” (VOS) research, which calculates the costs and benefits of DPV and estimates its impacts on retail electricity rates; and “hosting capacity,” which quantifies solar energy potential vis-à-vis the electricity market, rooftop availability, and the technical limitations of the transmission and distribution grids.
2. A building-by-building estimate of rooftop DPV capacity within a suburban Manassas, Virginia, study area, utilizing geographic information systems (GIS) data on local building stock and light detection and ranging (LiDAR) data on sunlight, shading, etc.
3. A scenarios analysis of the impacts of DPV on the electrical distribution grid, assuming the optimal placement of DPV systems across the study area.

This project was funded by a Virginia Commonwealth University (VCU) Presidential Quest Research Fund (PeRQ) grant. The work was completed by VCU faculty and graduate student researchers from the Urban and Regional Studies and Planning program in the L. Douglas Wilder School of Government and Public Affairs (referred to here as the “planning team”), and the Electrical and Computer Engineering department in the School of Engineering (the “engineering team”).

The goal of this report is to **improve our understanding of distributed solar PV (DPV) grid integration by demonstrating an interdisciplinary method for estimating DPV capacity at a city or neighborhood scale and modeling the optimal allocation of DPV to improve grid performance.**

Current Solar PV Market Trends

Data from the U.S. Energy Information Administration (EIA) (2018b) shows that the nation's total **installed solar PV capacity has more than doubled over the past two years, to over 41 gigawatts (GW) by the end of 2017, including over 16 GW from distributed systems. However, solar energy still only provides 2% of our nation's electricity** (U.S. Energy Information Administration, 2018c).

The costs of solar PV materials and installation are falling rapidly. **The median installed price of residential solar PV systems has dropped from over \$8 per watt in 2009 to under \$3 per watt by late 2017.** The price of non-residential and utility-scale systems is now as low as \$1 to \$1.50 per watt (Barbose & Darghouth, 2016; Perea, *et al.*, 2017). The levelized cost of electricity produced by PV systems, without factoring in any subsidies, has dropped to \$0.13 to \$0.17 per kilowatt-hour (kWh) for residential systems, and around \$0.05 per kWh for utility-scale systems (Fu, *et al.*, 2017).

Virginia has seen rapid growth in utility-scale solar, which went from having zero such facilities at the beginning of 2016 to the 14th leading state, **with almost 370 MW, by the end of 2017.** Distributed PV has also been increasing, from just over 5 MW in 2011 to 46.5 MW by the end of 2017, but **the state still ranks only 31st in total DPV and 38th in DPV per capita. Only 11% of the state's PV capacity is from distributed systems**, compared to 39% nation-wide, **which puts Virginia 45th among all states** in that regard (U.S. Energy Information Administration, 2017b; 2018b).

A number of studies have found that solar PV levels could be much higher, as discussed below under "Hosting Capacity Analysis and DPV Grid Integration."

Value of Solar Analysis

Our review of existing VOS studies indicates that the total net benefits of distributed solar energy are generally found to be positive in studies conducted on behalf of solar energy supporters, whereas those conducted on behalf of electric utilities tend to be less favorable. These differences are typically a function of the costs and benefits included in those analyses, most notably whether or not the value of greenhouse gas (GHG) reductions or other environmental benefits are included.

However, a number of VOS studies have also been conducted on behalf of independent state Public Utility Commissions (PUCs). Previously conducted meta-analyses by Environment America (Hallock & Sargent, 2015) and the Lawrence Berkeley National Laboratory (LBNL) (Barbose, 2017) both show that these **independent PUC studies tend to calculate a positive net value of solar, often in the same range as found in the studies funded by solar energy advocates.**

The LBNL report took the further step of stripping out all environmental and economic development-related values from the existing VOS studies, and recalculating their totals based strictly on values related to electricity generation and grid operations. Even without factoring in those societal benefits, nearly all of the independent PUC studies calculated a net-positive VOS.

The LBNL report also used the results of prior VOS studies to investigate the question of "cross-subsidization," i.e., the notion that increased solar energy capacity will provide savings to DPV customers at the expense of non-DPV customers. The author devised a formula to estimate retail rate impacts based on the VOS analysis results, existing electricity rates, and the market

penetration of solar PDV within a given electric utility's service area. Assuming that the value of energy produced by DPV systems is roughly in the neighborhood of the retail rate (give or take 25% for example), which is the case in the majority of VOS studies, **the LBNL study indicates that DPV market penetrations up to 5% would have no discernable impact on electricity rates.**

We used the LBNL formula to investigate the potential for cross-subsidization in Virginia, based on data from a 2011 State Corporation Commission (SCC) study. The SCC study estimated the costs and benefits that would result if net-metered DPV capacity were to reach the limits set forth in state law – 1% of the annual peak electrical power demand within each electric utility service area. **Using a relatively narrow range of VOS variables, the SCC study found that the net cost of reaching the 1% threshold for Virginia's utilities would translate to a retail rate increase of less than 0.5%, or \$6.73 per year for the average residential customer.**

Plugging the data from the SCC study into the LBNL formula, we calculated a similar retail rate increase of 0.33% at 1% DPV market penetration. We then extrapolated those results to higher DPV penetration rates, again using the LBNL formula. This analysis indicates that, **even under the very conservative VOS calculations from the SCC study, impacts on retail electricity rates would be minimal up to at least a 5% DPV market penetration.** For example, a 2% penetration rate, equal to a roughly 20-fold increase of current DPV capacity in Virginia, would increase retail rates by well under 1%, equal to a little over \$1 per month for the average retail electricity customer. A 5% penetration, well above current levels in any state other than Hawaii, would still only increase electricity rates by 1.67% and average residential bills by less than \$3 per month. (See further discussion of VOS studies and rate impacts in Section 2.1, pages 17-24).

Hosting Capacity Analysis and DPV Grid Integration

The question of “hosting capacity,” or how much solar energy can be integrated into the U.S. power supply, is one of intense research and speculation. Most studies address this issue from one of three perspectives: *market potential*, or projected customer demand for DPV systems under various economic and policy scenarios; *rooftop potential*, or the capacity of buildings to host DPV systems given their roof space, orientation, shading, etc.; and *grid-potential*, or the extent to which DPV that can be increased without damaging the grid infrastructure or causing significant technical problems.

A number of recent federal government studies have identified the potential to dramatically increase DPV capacity in the U.S. First, in 2012, the U.S. Department of Energy (DOE) *SunShot Vision Study* estimated that **solar PV market potential could reach 329 Gigawatts (GW) by 2030, including 121 GW from rooftop DPV**, and that those totals could exceed 700 GW and 300 GW respectively by 2050. The energy produced by those PV systems could provide 10.8% of total U.S. electricity demand by 2030 and 19.3% by 2050, with rooftop PV accounting for 3.5% and 5.9% respectively.

More recently, a DOE grid potential study (Palmitier *et al.*, 2016) found that **up to 170 GW of DPV capacity could be supported with existing grid distribution systems, and that advanced inverters could double the potential to 350 GW**, enough to provide 25% of the nation's electricity by 2050.

In addition, three studies from the National Renewable Energy Laboratory (NREL) show that rooftop potential is even greater, as **the current U.S. building stock is capable of supporting up to nearly 1,200 GW of DPV** (Paidipati *et al.*, 2008; Denholm & Margolis, 2008; Gagnon, *et al.*, 2016).

Table ES-1. Summary of Federal Government PV Hosting Capacity Studies

Study Authors / Date	Study Type	Estimate Year	Estimated PV Capacity (GW)		PV % of Electricity	
			Total	DPV	Total	DPV
EIA (2017, 2018a, 2018c)	<i>Current totals</i>	2017	41	16	2.0%	0.6%
DOE (2012)	Market potential	2030	329	121	10.8%	3.5%
DOE (2012)	Market potential	2050	714	318	19.3%	5.9%
Denholm & Margolis (2008)	Rooftop potential	2008		661		
Paidipati <i>et al.</i> , 2008	Rooftop potential	2008		712		
Gagnon, <i>et al.</i> , 2016	Rooftop potential	2016		1,168		39.0%
Palmintier <i>et al.</i> , 2016	Grid potential	2016		170		12.5%
Palmintier <i>et al.</i> , 2016	Grid potential	2050		350		25.0%

Virginia has tremendous potential to expand both its DPV and utility-scale solar energy capacity.

The 2007 and 2010 versions of the Virginia Energy Plan both estimated the state’s solar energy potential to be between 11,000 and 13,000 MW (Schlissel, Loiter & Sommer, 2013), and the aforementioned federal research studies found Virginia’s solar PV hosting capacity to be far beyond the current levels of 370 MW utility-scale and 46.5 MW of DPV.

For instance, the DOE SunShot Vision Study estimated **a combined utility-scale and DPV market potential for Virginia of 8,700 MW by 2030, and 21,200 MW by 2050** (U.S. Department of Energy, 2012). The two NREL rooftop potential studies found that **Virginia’s buildings could support from 21,800 MW** (Paidipati *et al.*, 2008) **to 28,500 MW of DPV** (Gagnon, *et al.*, 2016), the latter of which would be enough to provide nearly a third of the state’s annual electricity consumption. Finally, two other NREL studies estimated that **Virginia’s electrical grid infrastructure could support 19 GW of DPV**, more than 400 times the state’s current total (Denholm & Margolis, 2008; Lopez, *et al.*, 2012). (See further discussion of prior hosting capacity studies in Section 2.2.1, pages 25-28).

Technical challenges for DPV grid potential and hosting capacity

The technical concerns around DPV grid integration are ultimately rooted in the fact that DPV systems introduce bi-directional power flow to a distribution grid that was built to handle one-way flows only (St. John, 2013). While the installation of new DPV capacity can have grid benefits (Cohen, Kauzmann & Callaway, 2015; Perez, Norris & Hoff, 2012), under certain conditions an excess of DPV on a given segment of the distribution grid could cause technical problem such as reverse power flows, voltage variations, and current overloads (Bank, *et al.*, 2013; Denholm, *et al.*, 2014; Energy Storage Association, 2016; Liu & Bebic, 2008; Smith, 2012; Zhang, *et al.*, 2012).

Distribution system impacts vary greatly depending on the characteristics of individual circuit feeders and the loads that they serve. For example, **DPV systems near the end of a feeder line segment are more likely to cause problems than those installed closer to a substation. Problems are also more likely on long feeder lines with relatively low power demand, such as in rural areas.**

The typical rule of thumb has been the “15% rule,” which says that technical concerns should not arise as long as the aggregate DPV capacity on a distribution line or “feeder” remains below 15% of its annual peak demand. However, many distribution lines feeders can support far higher capacity penetrations, while in others technical problems could occur at levels below 15% (Hering, 2015).

A number of technical hosting capacity studies have been conducted at the state or regional level. While their methodologies, assumptions, and findings vary greatly, they collectively demonstrate that most distribution service areas can easily host at least 5% DPV penetration, if not much higher.

The most relevant of these studies to Virginia is a GE Energy report for the PJM Interconnection region. It found that, **with sufficient grid investments, the PJM region could get up to 30% of its electricity from wind and solar sources, including around 5% - 9% from DPV. This level of renewable energy integration would result in reduced fuel costs, operations and maintenance costs, and Locational Marginal Prices, without any significant operating issues** (GE Energy, 2014b).

Transmission and distribution grid hosting capacity studies for Dominion Energy

In 2016, Navigant Research completed two comprehensive solar energy grid integration studies on behalf of Dominion Energy, as part of the DOE-funded “Virginia Solar Pathways” project.

The first of these modeled DPV hosting capacity on Dominion’s 1800 distribution feeders, which Navigant divided into 11 “clusters” of feeders with similar voltage, load, customer distribution, and other characteristics. They then selected representative feeders within each cluster, to evaluate the level of DPV penetration at which distribution system upgrades would be required. This evaluation was done in a manner consistent with Dominion’s own “planning and operating standards and evaluation criteria” (Navigant Consulting, 2016a, p. 23).

Navigant’s analysis found that most of the representative feeders incurred no upgrade costs at DPV penetration levels up to 50% of their feeder thermal rating (i.e., the maximum amount of current that the line itself can sustain before sustaining damage). **The feeders that would incur costs at lower penetration levels were those with “significant lengths of low-voltage sections” and with lighter, more dispersed loads** (Navigant Consulting, 2016a, p. 29). One such feeder (identified as #11 in the study) still required no upgrade costs at up to 7.5 MW of DPV penetration, or 25% of its feeder thermal rating (p. 28). **To put this in perspective, Navigant found that this single feeder, with known structural challenges and zero upgrades, could still support enough DPV to increase Virginia’s total statewide capacity by more than 15%.**

Furthermore, **the 11 representative feeders evaluated by Navigant could host over 200 MW of DPV just by themselves, or more than four times Virginia’s current state-wide capacity.**

Extrapolating the results from the representative feeders to the rest of Dominion’s 1800 such feeders produces a rough estimate of around 23 GW, on a similar magnitude to the 19 GW of technical potential estimated for Virginia by NREL (Denholm & Margolis, 2008; Lopez, et al., 2012).

However, it is important to note that two of the representative feeders had a hosting capacity of 0 MW, which reinforces the notion that technical problems can still arise in certain situations.

The second Navigant study focused on larger-scale impacts of utility-scale solar and DPV on Dominion’s generation and transmission networks. It found that, **at a minimum, Dominion could integrate at least 1,600 MW of solar PV capacity, with few upgrades to its transmission and generation systems** (Navigant Consulting, 2016a, p. 46-47). Beyond that, **the point at which transmission upgrades are necessary can “be assumed to range between 2,000 and 4,000 MW”** (p. 35), **while the “point of criticality” for the generation system would not occur until “solar capacity exceeds 8,000 MW”** or about 40 to 50% of Dominion’s peak demand (p. 44).

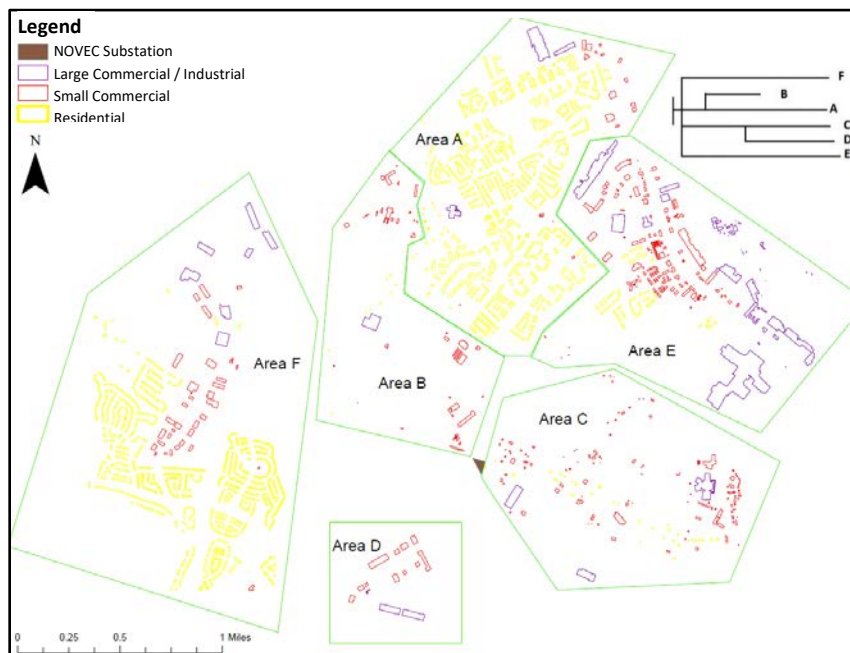
(See further discussion of the Virginia Solar Pathways studies in Section 2.2.2, pages 28-31).

Estimating DPV Capacity and Energy Production Potential at the Distribution Grid Scale

The first phase of our research was to build a study area map for an individual sub-station-level distribution grid in Virginia, and to estimate the potential rooftop DPV capacity and resulting solar energy electricity generation potential for individual buildings in the study area.

We began by obtaining real data on hourly load demand in 2015 for a specific sub-station in the Northern Virginia Electric Cooperative (NOVEC) electric utility service territory outside Manassas, Virginia. The utility also provided data on the total number of customers served by that sub-station, divided by customer class: residential, small commercial, and large commercial / industrial. However, for security reasons the utility could not provide the exact location of the customers served by that sub-station, or the lay-out of distribution feeders that connect those customers.

Figure ES-1. Study Area Base Map



The planning team then used geographic information systems (GIS) data from Prince William County to map **a study area that represents a hypothetical service area for the target sub-station**. Our study area (see Figure ES-1) does not represent the exact sub-station service territory, but it does include the same number of residential, small commercial, and large-commercial / industrial buildings as are found in the sub-station territory, many of which are likely the same buildings that it actually serves.

Using the planning team’s base map, the engineering team identified a logical alignment of distribution feeders and branch lines that could serve all of the buildings in the study area. We then divided the study area into six sub-regions representing the buildings served by each feeder.

Using LiDAR data from the US Geological Survey, we determined the average annual incident solar radiation (“solar insolation”) received on the rooftops of each building in the study area, taking into account building orientation, shading, and other obstructions (e.g., rooftop HVAC system, etc.). With this data **we identified as “solar-ready” those buildings that had high concentrations of rooftop surface area receiving above-average annual solar insolation. A little over 1/3 of the buildings in the study area met this criteria.** For example, Figure ES-2 shows a grouping of residential apartments in the study area, sorted by the percentage of rooftop area that receives above-average annual solar insolation. Only the buildings in red – each of which has a largely unshaded flat or south-facing rooftop – were designated as solar-ready in our model.

We then **calculated the potential installed DPV capacity and average annual electricity generation** for those solar-ready buildings, using each one’s unique average annual solar insolation. Our calculations employed relatively conservative estimates for PV system efficiency and de-rating factors. Finally, we aggregated these individual building results to determine the total DPV capacity and electricity generation potential within each sub-region and customer class (see Sections 3.1 - 3.2, pages 32-38, for more detail on the study area and DPV capacity methodology).

Figure ES-2. Insolation Density in Study Area Buildings



This analysis found **the study area’s total DPV rooftop capacity to be just under 25 MW, equal to 107% of the total sub-station area peak load**, as shown in Table ES-2. The annual electricity production potential from those systems is 32,310 mWh, **enough to provide 28% of the actual annual electricity demand** in the NOVEC sub-station’s service area. **Furthermore, the potential rooftop DPV capacity in just this study area is equal to more than half of the current state-wide DPV total in all of Virginia, as of the end of 2017.**

Table ES-2. Solar PV Capacity and Electricity Production Potential by Building Type

Building Type	Potential Solar PV Buildings	Average Potential PV Coverage (kW DC)	Total Potential PV Coverage (kW DC)	Share of Potential PV Coverage	Total Potential Energy (MWh)
Residential	510	17.56	8,953	36%	11,979
Small Commercial	119	58.76	6,993	28%	8,998
Large Comm. / Ind.	26	341.69	8,884	36%	11,332
Total	655		24,830		32,310

It is important to reiterate that **these findings are the result of a very conservative assessment of potential DPV capacity in the study area**. We assumed that DPV would only be placed on buildings where a high percentage of the rooftop surface area had above-average solar insolation, and then that only half of the high-insolation surface area on those buildings would be utilized for PV systems. This methodology places PV on only 10% of residential rooftop space, 14% of large commercial and industrial rooftop space, and 16% of small commercial rooftop space. By comparison, the NREL study that estimated Virginia's total rooftop solar potential to be 21,837 MW estimated that 22%–27% of residential rooftop area is suitable for PV systems, along with 60%–65% of commercial rooftop area (Paidipati *et al.*, 2008). (See Section 3.3, pages 38-39, for more detail on the DPV capacity analysis results).

Modeling DPV Hosting Capacity on Distribution Grid

The second phase of our study was to build a hypothetical grid network model for the study area and evaluate the impacts of increasing level of DPV capacity on that grid model.

To begin this phase, the planning team used GIS data and other available sources to identify the current land use for each building in the study area (e.g., single family detached home, small office, restaurant, etc.). We then assigned each building to the appropriate residential or commercial building category found in the OpenEI community data set (OpenEI.org, 2013). This data set provided estimated annual hourly load profiles for each of those specific building types, which the engineering team used to estimate annual energy consumption and hourly power demand curves for each building. **The engineering team then built a hypothetical electrical distribution model based on the existing buildings in the study area and their distribution by sub-area, customer class, and building type.** The model aggregated the buildings in each sub-area by customer class, then re-allocated them to individual distribution buses along the six distribution feeders.

The final model, shown in Figure ES-3, had a total of 119 buses. Each bus is identified by number (i.e., buses 80 through 119 are on distribution feeder F, at the top of the diagram), is color-coded to identify which building type it serves, and is marked with an asterisk if it serves any buildings identified as “solar ready” in the Phase I research. The engineering team also calculated the peak load for each bus, indicated with an arrow pointing from the bus number to the corresponding load number (i.e., bus 79 on feeder E has a peak load of 140 kW). (See Sections 4.1 - 4.2, pages 40-44, for more detail on the building of the electrical distribution system model).

This base hypothetical electric distribution model was then used to simulate the distribution grid impacts that could be expected from four DPV market penetration scenarios – 5%, 10%, 20%, and 50% – defined as total DPV capacity divided by the actual year 2015 peak demand for the study area sub-station. It is important to clarify that the engineering model scenarios do not distribute DPV capacity randomly across the system. Rather, **the model seeks to identify the ideal allocation of DPV across the distribution system buses that would produce optimal system performance.** Specifically, the model sought to reduce system-wide energy losses and voltage deviations, while avoiding reverse power flows.

Figure ES-3. Schematic Diagram of Modeled Distribution Network

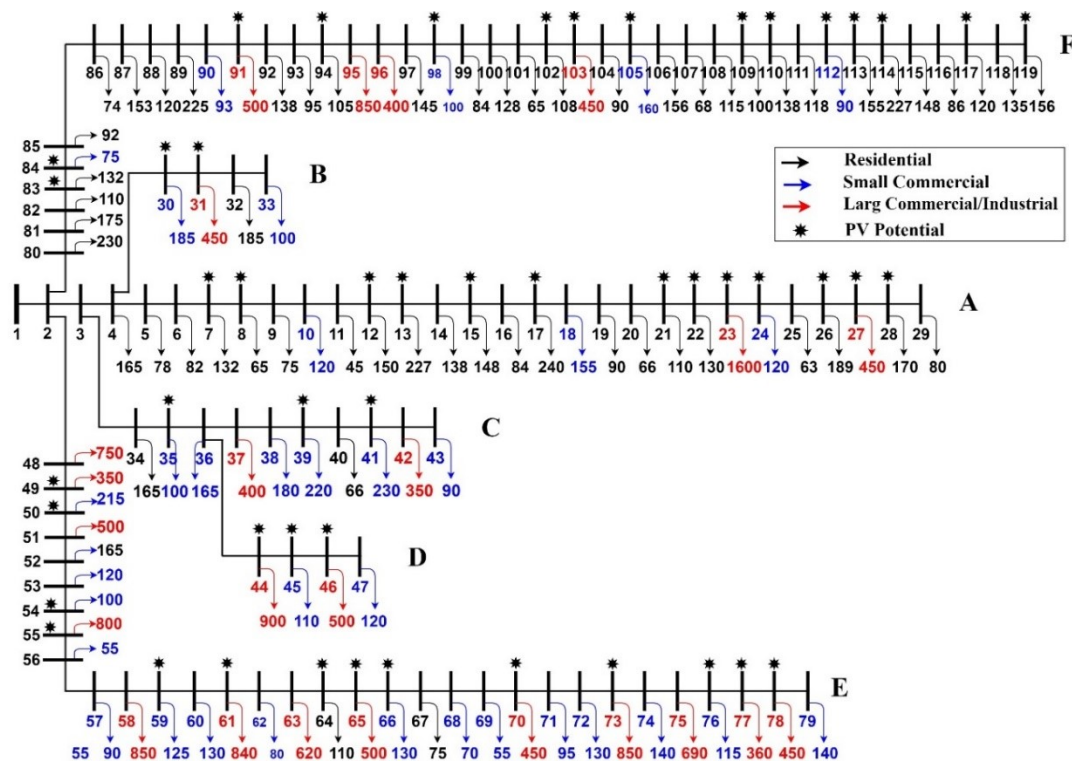


Table ES-3 shows that **the model resulted in reduced energy losses and voltage deviation under each scenario, indicating that optimized DPV penetration improves distribution system performance.** Energy losses are reduced with each increasing level of DPV penetration, whereas voltage deviation is lowest in the 20% scenario.

Table ES-3. Distribution System Performance under Optimized DPV Penetration Scenarios

Scenario	Total DPV (MW)	Energy Loss (kWh)	Voltage Deviation	Energy Loss Improvement	Voltage Deviation Improvement
Base Case	NA	26,995	1.8315	NA	NA
5% Penetration	1.16	26,081	1.7372	3.39%	5.15%
10% Penetration	2.15	25,837	1.6759	4.29%	8.50%
20% Penetration	4.65	24,092	1.6102	10.75%	12.08%
50% Penetration	11.63	22,998	1.6295	14.81%	11.03%

On average, across the four scenarios, **the optimal allocation of DPV capacity by customer class was 34% on residential buildings, 12% on small commercial buildings, and 55% on large commercial and industrial buildings.** Interestingly, the optimal distribution of DPV in the 50% market penetration scenario is exactly the same as the distribution of peak load by customer class:

29% residential, 15% small commercial, and 56% large commercial / industrial. (See Section 4.3, pages 44-46, for more detail on the DPV distribution simulation findings).

Conclusions and Discussion

Our findings illustrate the tremendous potential for continued DPV growth, both in Virginia and across the U.S., with positive net economic benefits. As discussed above, Virginia ranks 31st among all states in total DPV capacity, 38th in DPV per capita, and 45th in DPV as a percentage of total PV capacity. Prior studies have shown that Virginia could support far higher levels of DPV penetration, and our research corroborates those findings at the local scale.

There is no evidence to suggest that increasing Virginia's DPV market penetration to at least 5% would cause notable retail price increases, and most recent independent VOS studies have found the net benefits of electricity from DPV systems to be equal or above the applicable retail rate. To provide clarity on Virginia's DPV policy debate moving forward, the state should commission an independent VOS study that quantifies the net-benefits of DPV and analyzes the potential electric rate impacts from increased DPV versus business-as-usual rate increases and other future scenarios.

While net metering remains the most appropriate mechanism for compensating DPV "customer-generators" in the short term, it has clear limitations as a long-term solution for a changing electricity landscape, particularly if DPV market penetration rises to the levels that many solar energy supporters envision. Net metering does not account for the fact that electricity is more valuable at different times, and at different locations on the grid, and it creates a disincentive for DPV owners to invest in on-site energy storage and other load-shifting behaviors. Some states are therefore exploring "post-net-metering" models that quantify the various component values provided by DPV systems, such as a temporal value that would be higher for electricity delivered at times of peak demand. For example, New York has developed a model, as part of that state's broader Reforming the Energy Vision (REV) process, that provides higher compensation to DPV systems located in parts of the distribution grid where it would be most beneficial.

Our research presents a method by which such location-specific values could be incorporated into a new post-net-metering compensation model. Following the steps we have demonstrated here, electric utilities can work with urban planners to estimate building-specific energy demand curves and DPV production potential within a given distribution service area, model the potential of the feeders in that area to absorb additional DPV capacity, and identify specific locations where DPV capacity would provide the most locational value to the grid.

Finally, our analysis shows that the optimal distribution of DPV within an urban / suburban context would include a high proportion of systems on commercial buildings. This result makes intuitive sense, as 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. Our findings suggest that state and local policymakers should develop policies that support the growth of DPV in commercial districts. Such approaches could include streamlining local permitting processes and removing unnecessary zoning and building permit obstacles, allowing third-party ownership models such as Power Purchase Agreements and "shared" or "community" solar arrangements for DPV arrays on commercial

buildings, facilitating the growth of PACE loan programs in the commercial sector, and creating state and/or local financial incentives for commercial-sector DPV systems.

1. Introduction

Solar energy has recently become a subject of heated policy debate in state governments across the United States (U.S.). Proponents note that solar energy provides a variety of environmental, public health, and economic development benefits for society. They also argue that it can help electric utilities save money on conventional generation fuels, avoid new generation capacity investments, and reduce the strain on existing transmission and distribution infrastructure.

However, many electric utilities and other opponents contend that solar energy creates costs for utilities that will then be passed on to ratepayers. One of their primary arguments is that increased levels of solar energy use can pose technical challenges (e.g., reverse power flows and substation voltage variations) for the effective and reliable operation of transmission and distribution grids. These concerns are most often raised in regard to distributed solar photovoltaic (PV) energy systems, i.e. small- to medium-sized solar energy conversion systems that one might place on the roof of a home or business.

This research project seeks to improve our understanding of distributed solar PV (DPV) grid integration by demonstrating an interdisciplinary method for estimating DPV capacity at a city or neighborhood scale and modeling the optimal allocation of DPV to improve grid performance. It was funded by a Virginia Commonwealth University (VCU) Presidential Quest Research Fund (PeRQ) grant, received in May, 2015 by Dr. Damian Pitt from the Urban and Regional Studies and Planning program in the L. Douglas Wilder School of Government and Public Affairs at VCU. Dr. Pitt and his team of graduate student researchers completed the work found in Sections 1-3 and 5 of this report. The research described in Section 4 was conducted by Dr. Zhifang Wang and her team of graduate students in the Electrical and Computer Engineering department in the School of Engineering at VCU.

This first section of our report begins with a background on the fundamentals of distributed solar energy and a review of recent solar energy market trends. We then discuss the benefits and challenges of DPV, and the resulting policy debates across the U.S. The introduction closes with a review of solar energy capacity, market trends, and policy debates in our home state of Virginia. Section 2 then reviews the current research on two emerging issues related to DPV grid integration: 1) the “value of solar” and the impacts of distributed PV on electricity rates; and 2) the “hosting capacity” or amount of solar DPV that can effectively be placed on the grid.

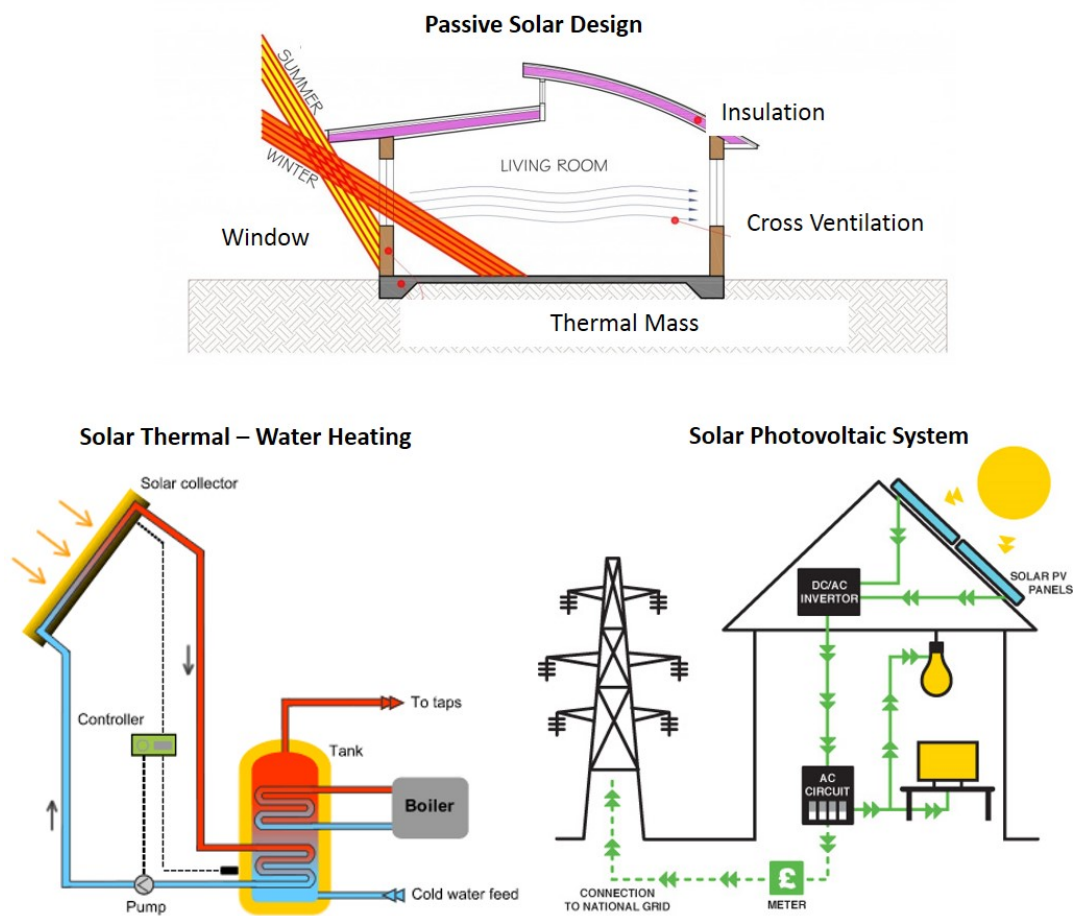
Section 3 describes our process for defining the study area – based on the service area for an electrical distribution sub-station in suburban Manassas, Virginia – and estimating its potential rooftop DPV capacity via geographic information systems (GIS) analysis. Section 4 describes the engineering team’s work to build a hypothetical electrical distribution model for the study area. It then presents their analysis of how placing DPV systems at optimal locations in the study area grid network can maximize DPV market penetration and minimize negative grid impacts.

Finally, Section 5 summarizes the key findings of this study and discusses them in the context of the broader policy debate on distributed solar energy. It concludes with a series of observations about how these findings can inform future policy decisions aimed at increasing the use of distributed solar energy while minimizing potential negative impacts to the distribution grid.

1.1. The Basics of Distributed Solar Energy

Solar energy can be utilized in many forms. “Passive solar” design allows a building to maximize solar heat gain (i.e., the heat of sunlight, coming through windows, walls, etc.) in the winter months while minimizing it in the summer. Active “solar thermal” energy systems use sunlight to provide water or space heating to a building. Large-scale “concentrated solar” power plants use mirrors to reflect sunlight onto a receiving tower, which uses that heat to create steam and thus generate electricity. The most visible and well-known form of solar energy comes from solar photovoltaic (PV) systems, which convert sunlight directly to electricity, without the need to generate steam or utilize any external fuel source.

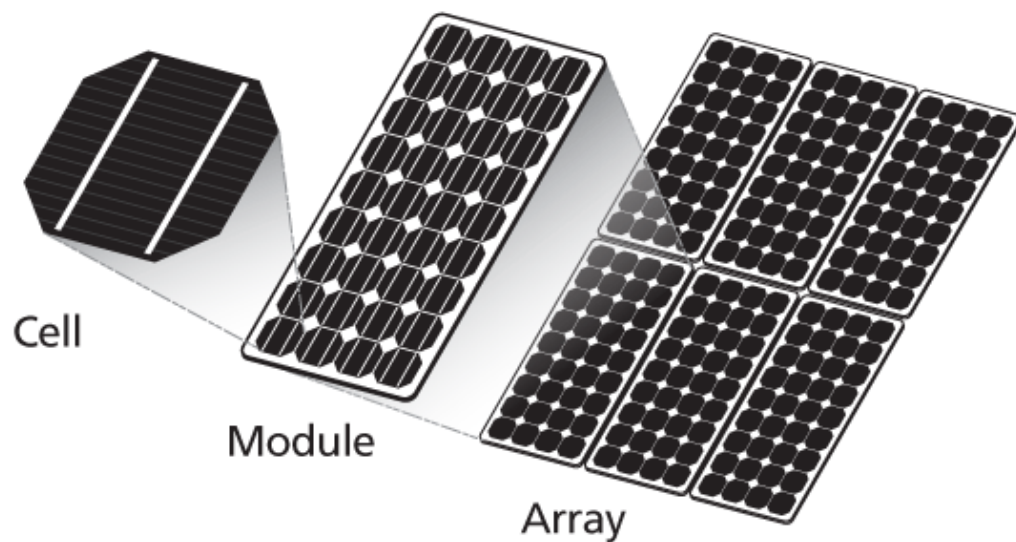
Figure 1. Three Types of Solar Energy Systems



Sources: Darling, 2016; EcoLiving Design, 2016; Solec Energy Solutions, 2016

A solar PV system consists of an array of solar modules or “panels.” The panels are themselves made up of solar cells, which are small semiconductors made from silicon and other conductive materials (Richards & Green, 2006). Sunlight hitting these cells creates a chemical reaction that releases electrons, generating a direct (DC) electric current. The system typically includes an inverter, which converts the DC power to alternating current (AC) power, for direct use in a nearby building or delivery to the electrical grid (Vignola, Mavromatakis, & Krumsick, 2008).

Figure 2. Solar Photovoltaic (PV) Cell, Module, and Panel



Source: Samlex Solar, 2016

Solar PV systems are measured by their installed power-generating capacity, in kilowatts (kW) or megawatts (MW), with each panel producing around 200-250 watts on average.¹ This power measurement refers to how much electricity the system can produce at a single moment, under ideal conditions (National Renewable Energy Laboratory, 2013). Electrical energy, on the other hand, is a measure of power times time, as measured in kilowatt-hours (kWh) or megawatt-hours (MWh) (National Grid, 2005).²

To maximize their electrical output, solar panels installed in the northern hemisphere are almost always aligned to face south. This optimizes the average daily amount of incident solar radiation, or “solar insolation,” that the system will receive over the course of a year (Lisell, Tetreault, & Watson, 2009). Direct, unshaded sunlight on a PV system produces an average of about 1 kW of power per square meter of surface area, a metric known as “one-sun” insolation. The “sunniness” of a given PV system location is measured in terms of the average daily number of hours of this “one-sun” solar insolation. Average annual insolation is maximized when the tilt of the panels relative to the horizon is roughly equal to the latitude at which the system is located (Randolph & Masters, 2008). In the U.S. these values range from about 3 to 8 kwh/m²/day, as shown in Figure 3. For instance, the latitude of Richmond, Virginia is 37.5° north, and a panel in that location will achieve an average solar insolation of around 4.5 – 5.0 kwh/m²/day with a tilt of anywhere between 30 and 45 degrees.

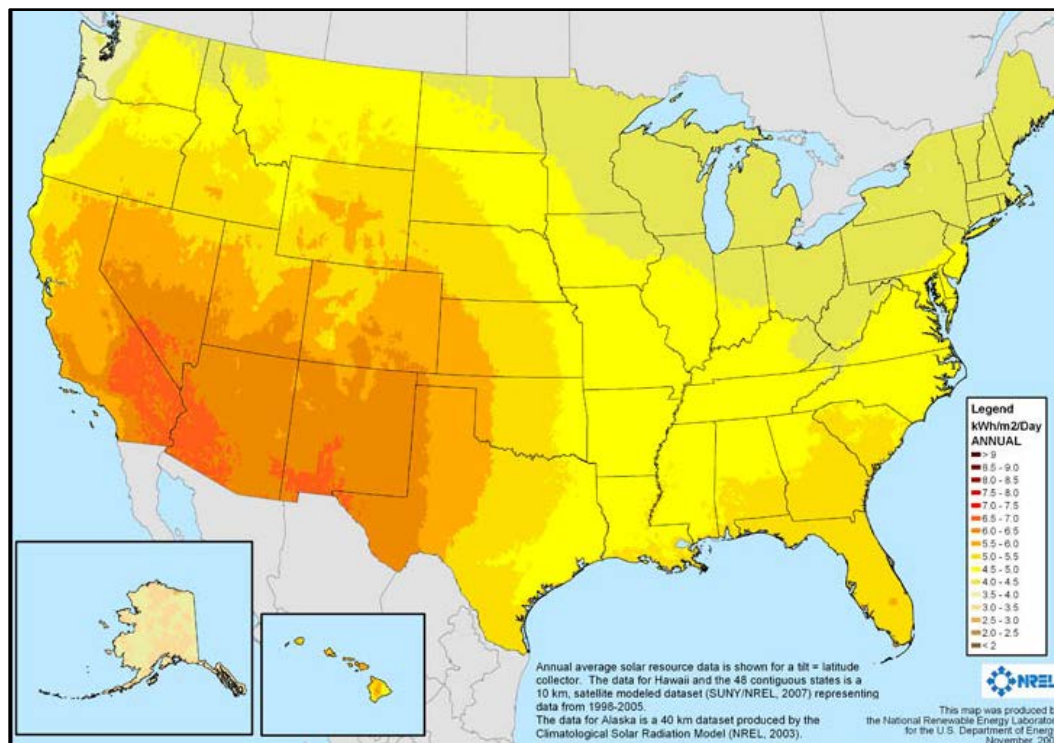
Solar PV systems come in a variety of sizes. They are typically lumped into three categories, although there is no strict definition or general consensus on the size limits for each category. The

¹ The basic measure of electrical power is a watt, which is equal to one Joule per second, or one ampere times one volt. One kilowatt (kW) is equal to 1000 watts, and one megawatt (MW) is equal to 1,000 kW or 1,000,000 watts.

² For example, a 10 kW system operating at full capacity for 2 hours would produce 20 kWh of electricity.

largest, “utility-scale” PV systems have a capacity of between a few dozen to upwards of hundreds of MW, and are connected directly to the electrical transmission grid. Mid-sized systems are typically referred to as “commercial” scale, in that they tend to serve commercial customers (e.g. shopping malls or major retail centers, factories or warehouses, government or educational buildings, etc.). This research focuses on the smallest category, “distributed” PV systems. Traditionally this term refers to smaller systems, up to perhaps 10-20 kW, that are placed on a home or small business and are primarily intended to provide a portion of that building’s electricity needs. However, in many contexts this category is defined more broadly, including much of what otherwise would be considered commercial-scale systems.

Figure 3. Average Annual Solar Insolation for a PV Panel Tilted South at Latitude



Source: National Renewable Energy Laboratory, 2008

This study adopts the definition of “distributed solar” from the Virginia Solar Stakeholders Group (SSG), formed in 2014 by the Virginia Department of Environmental Quality (DEQ) and the Virginia Department of Mines, Minerals, and Energy (DMME) to study the costs and benefits of distributed solar energy. The SSG defined “distributed solar” as:

“any grid-integrated system that meets each of the following criteria:

- The system is connected to the distribution grid, not directly to the transmission grid.
- The system output is no greater than 69 kilovolts (kV).
- The installed capacity does not exceed the limits established in the state’s net-metering legislation (i.e., up to 20 kW for a system on a residential building or 500 kW for a system on a commercial building). The only exception here would be larger systems

participating in Dominion's Solar Partnership Program (which has a maximum size of 1 MW), or any similar program to be adopted by other utilities.

Any PV system set up behind the retail meter (i.e., between the customer and the distribution system) would meet the definition of distributed generation and should be evaluated as a demand-side resource. A PV system connected behind the wholesale meter (i.e., between the distribution and transmission systems) may also be considered distributed if it otherwise meets the criteria above, but should be evaluated as a supply-side resource. Both rooftop and ground-mounted solar PV systems can meet these criteria" (Pitt & Michaud, 2014).

Distributed solar PV systems (hereafter referred to as "DPV" systems) are one of the most practical ways to deliver energy to a building. When equipped with a battery back-up system, they can supply a building's electricity load without connecting to the generation, transmission, and distribution infrastructure of the electricity grid. However, the vast majority of solar PV systems are now grid-connected, allowing the building to still draw electricity from the grid when needed, in which case battery back-up systems are not required.

Grid-connected buildings with solar PV systems can also return excess electricity that the system generates to the electrical distribution grid. In a majority of states, electric utilities are required to purchase this excess electricity at the standard retail rate (Darghouth, Barbose & Wiser, 2011). These state "net-metering" programs most often take the form of a direct kWh-for-kWh offset on the DPV system owner's electricity bill (Cai, et al., 2013). Net metering has been a major driving force in the growth of DPV, as it allows system owners to receive benefits for the excess electricity generated during periods of high production, while also accessing electricity from the grid at times when their systems are not producing (e.g., at night), thus negating the need for expensive battery storage (Hughes & Bell, 2006).

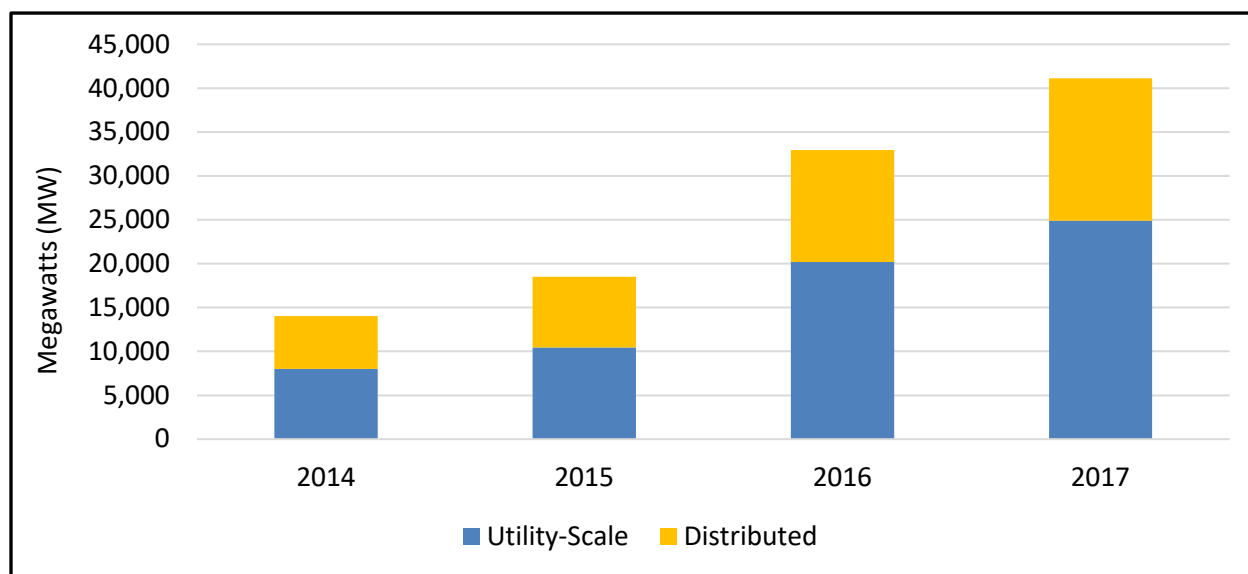
The rapid increase in net-metered DPV systems has raised concerns about the technology's implications for the electric utility business model and its impacts on the electricity distribution grid. These concerns have led to suggestions for alternative compensation models that more accurately reflect the locational and temporal nature of the benefits DPV can provide to the grid.

1.1.1. Recent Solar PV Market Trends

Total solar PV capacity in the U.S. has increased from only 1.2 gigawatts (GW) in 2008 (equal to 1,200 megawatts or 1,200,000 kW) to nearly 40 GW at the end of 2017 (US Department of Energy, 2018; US Energy Information Administration, 2018b). Roughly half of this total was installed in the past two years alone (see Figure 4). While utility-scale PV comprises the majority of this capacity, US Energy Information (2017c) data shows a total of 13.5 GW of DPV by the end of 2016. Solar energy accounted for between 27-30% of all new electricity generating capacity each year from 2013-2017, with the exception of 2016 when it accounted for 43% (Solar Energy Industries Association, 2018).

However, despite this growth, solar energy still accounted for only 2% of the overall generation in the U.S. electric power sector in 2017 (including both utility-scale and small-scale production), with the largest percentages still coming from natural gas (32%), coal (30%), and nuclear power (20%) (U.S. Energy Information Administration, 2018c).

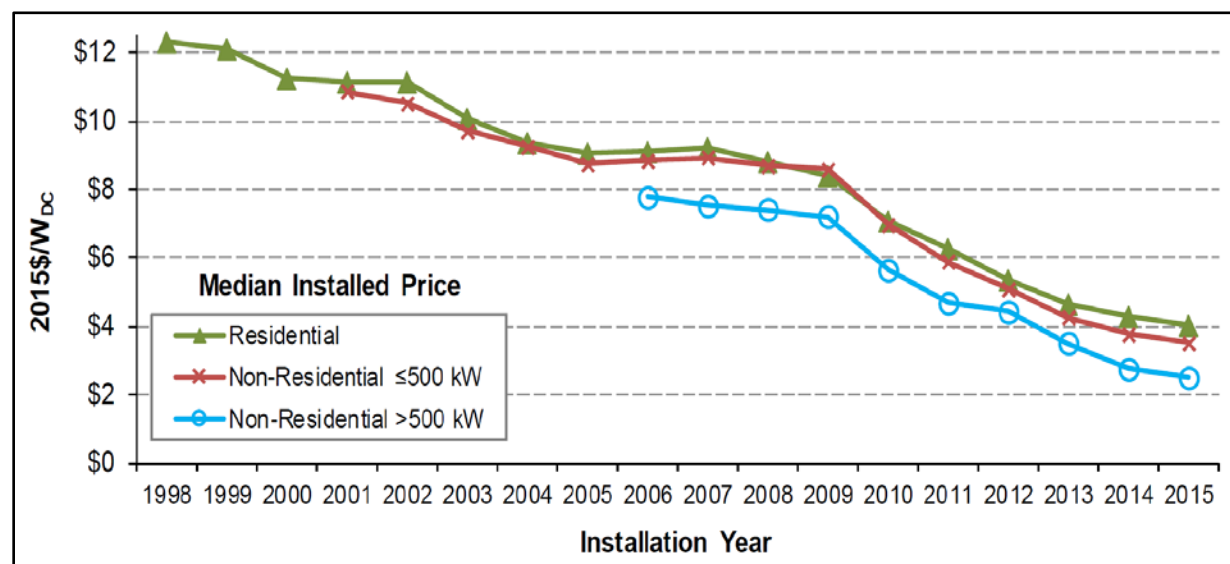
Figure 4. Cumulative U.S. Utility-Scale and DPV Capacity (MW), 2014–2017



Source: U.S. Energy Information Administration, 2016; 2017b; 2018b

The rapid growth of solar PV is associated with dramatically falling costs for solar PV materials and installation. As shown in Figure 5, the median installed price of residential solar PV systems dropped 50% from 2009–2015, from an average of over \$8 to about \$4 per watt, with larger non-residential systems dropping to just over \$2 per watt (Barbose & Darghouth, 2016). A more recent study estimated average costs to be just under \$3 per watt by late 2017, with non-residential and utility-scale systems at around \$1 to \$1.50 (Perea, et al., 2017). The levelized cost of electricity produced by PV systems, without factoring in any subsidies, has dropped to \$0.13 to \$0.17 per kilowatt-hour (kWh) for residential systems, and around \$0.05 per kWh for utility-scale systems (Fu, *et al.*, 2017).

Figure 5. Price Trends for DPV System Installations, 1998–2015



Source: Barbose and Darghouth, 2016

1.1.2. Benefits and Challenges of Distributed Solar PV

Solar energy provides numerous environmental and public health benefits, and is increasingly seen as a source of job creation and driver of economic development. It can also provide technical benefits that help to build a more secure and resilient electrical grid. However, higher levels of solar electricity generation, particularly from distributed PV, will create a variety of economic and technical challenges that are not easily addressed under conventional business models for electricity provision. These challenges are introduced here and then discussed in greater detail in Section 2.

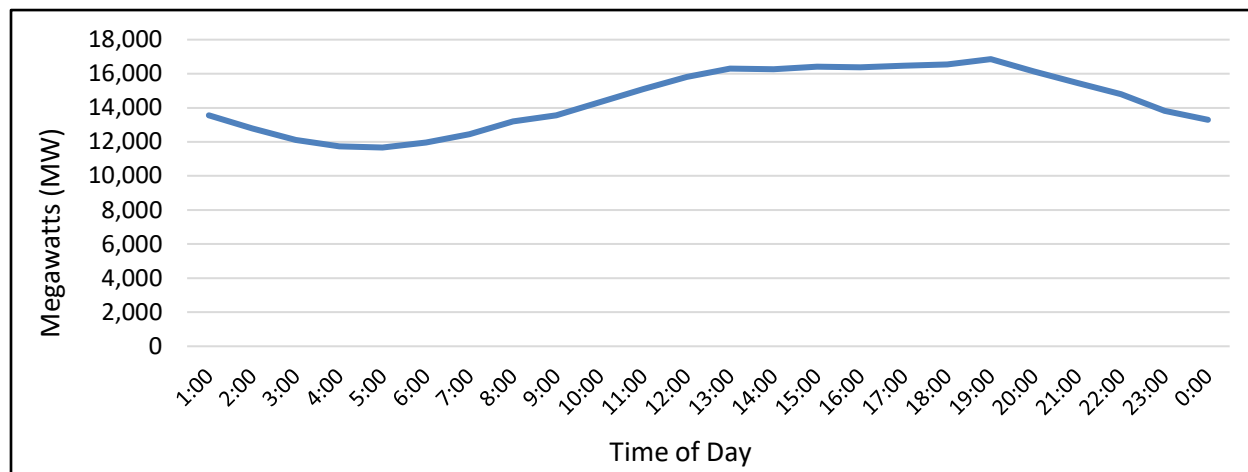
The most obvious environmental and public health benefits of solar energy come from avoiding the direct air pollution and carbon dioxide emissions that would otherwise be produced via fossil-fuel generation. Solar energy also provides ongoing indirect environmental benefits by reducing the need for fuel extraction (i.e., coal mining, natural gas drilling, etc.) and disposal of conventional generation by-products (e.g., fly ash from coal-fired power plants, hazardous waste from nuclear energy facilities, etc.).

The growth of solar energy is also helping to create job new opportunities, which leads to spin-off economic activity benefitting local economies (U.S. Department of Energy, 2011). In fact, a report issued by the U.S. Department of Energy (DOE) in early 2017 found that solar energy employed more workers than any other energy sector besides oil and petroleum. The 374,000 total workers in solar energy was slightly more than the 362,118 employed in the natural gas sector, and more than double the 160,119 employed in coal, with the latter two categories including jobs in both fuel supply and power generation. Oil and petroleum accounted for just over 500,000 jobs, almost entirely in fuel supply (U.S. Department of Energy, 2017). Solar energy can also support additional job growth related to research and innovation as well as the manufacturing of PV modules and related support equipment (Rogers & Wisland, 2014; The Solar Foundation, 2016).

To consider the technical benefits and challenges that solar energy poses, one must first understand that the electrical grid functions as one giant circuit. This means that grid operators must constantly match the amount of electrical power generated with the precise level of demand within a given distribution network (Roggenkamp, et al., 2012). The traditional electrical load curve in most locations rises in the middle of the day, drops a bit in the late afternoon, then reaches its highest “peak demand” point in the early evening. This curve is shown in Figure 6, which depicts the load in the Dominion Energy service territory on a typical hot summer day.

The minimum amount of power required at all times (i.e., the power demand in the middle of the night according to Figure 6) is provided by “baseload” units, which are large, centralized generation facilities (typically nuclear or coal-fired) that run all of the time and are difficult to turn on and off. “Intermediate” plants are then used to meet regularly occurring demand increases beyond the base load, generally in the afternoons and early evenings. These intermediate plants are often natural-gas fired, and are more dispatchable than baseload units, meaning they can be turned on and off relatively easily (National Renewable Energy Laboratory, 2010). At times of extremely high power demand (e.g., hot summer afternoons), grid operators utilize “peaking” plants, which are generally less efficient, more expensive, and highly polluting (Contreras, et al., 2008).

Figure 6. Electrical Demand Load Curve for Dominion Energy Territory on July 15, 2016

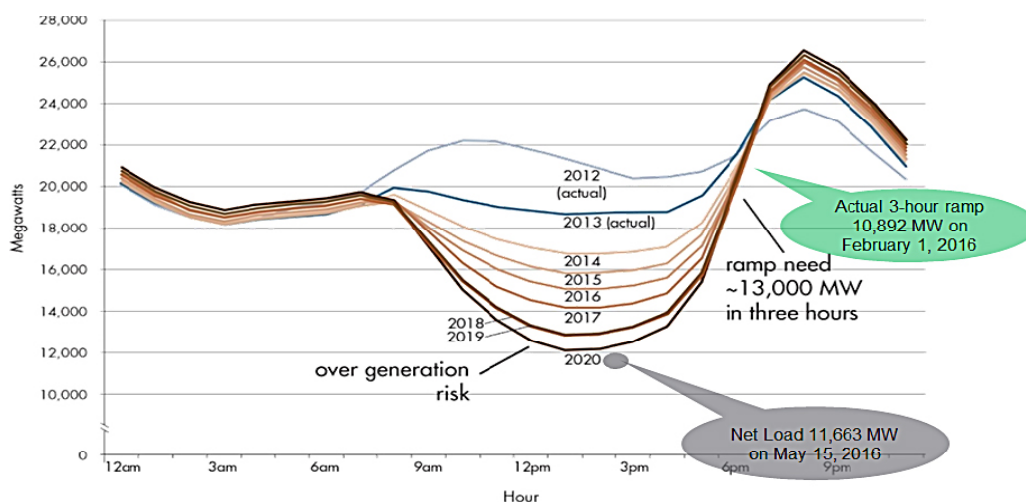


Source: PJM, 2016

The intermittent nature of solar energy presents a unique challenge, as it is available only during the daytime and is subject to changes in solar irradiance and cloud cover (Letendre, Makhyoun & Taylor, 2014). Unlike conventional centralized generation, solar PV cannot be turned on and off to match the needs of the grid, leaving grid operators with the challenge of meeting a less predictable “net load,” which can be defined as the electrical power demand in a given area minus the solar PV production in that area at any given moment.

Additionally, under high levels of solar PV, mid-day over-generation could cause the net load in a given grid region to drop below the typical baseload level. This would create additional challenges for grid operators, forcing them to choose between an expensive temporary shut-down of baseload plants or the “curtailment” (i.e., disuse) of electricity produced from renewable sources, followed by a rapid and expensive ramp-up of centralized power as PV generation wanes. This is sometimes referred to as the “duck curve” problem, as illustrated in Figure 7.

Figure 7. Potential Over-Generation and Steep Ramping Needs from PV Oversupply



Source: California Independent System Operator, 2016

The unique nature of solar PV compared to other generation sources leads to questions about DPV's big-picture, long-term impacts on generation, transmission, and distribution. 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). However, electric utilities often argue that, due to its intermittent nature, DPV cannot displace future generation capacity costs even at high levels (Pacific Northwest National Laboratory, 2014). They also express concern that high levels of DPV production could lead to revenue losses that would make it difficult for utilities to pay off the costs of their existing generation capacity.

As with other distributed generation technologies – small wind turbines, natural gas micro-turbines, etc. – DPV offers benefits related to electricity transmission (i.e., moving electricity long distances from the point of generation to the area in which it is consumed). First, by connecting directly to the local utility distribution grid, DPV reduce the transmission line losses associated with centralized generation systems such as large coal, natural gas, or nuclear power plants (Stanford University, 2010). Other potential benefits include easing congestion on transmission lines and avoiding the need for transmission upgrades. Conversely, however, very high levels of DPV market penetration could create the need for new transmission system upgrades (Rocky Mountain Institute, 2013).

This study focuses on DPV's impacts to the distribution grid. 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). However, technical problems such as voltage variations and reverse power flows can potentially arise when DPV systems return too much power back to the distribution grid (Denholm, *et al.*, 2014). Fortunately, technical and policy solutions such as advanced inverters, energy storage, and demand-side management programs can support increased levels of DPV while minimizing these concerns.

The fundamental questions then become, how much DPV can distribution grids sustain, under current conditions, and how much more can be accommodated with improved technology and policies? In technical terms, these are questions of "hosting capacity," or the percentage of DPV that can be interconnected into an existing distribution grid without damaging the grid infrastructure or causing significant technical problems such as those described above. Hosting capacity varies based on the individual characteristics of each distribution feeder line (line length, voltage, number and type of customers, etc.). Hosting capacity can be defined in terms of "energy penetration," the percentage of total annual electricity consumption provided by DPV systems within a given area, or "capacity penetration," which is the installed DPV capacity on a given circuit divided by its peak demand. The "minimum hosting capacity" is the amount of DPV that can be installed anywhere on a given distribution feeder line without causing any operational concerns. Above the minimum hosting capacity, and up to the "maximum hosting capacity," DPV systems must be carefully located in order to avoid such concerns. These hosting capacity levels can be raised through the use of advanced inverters, control equipment, and other distribution infrastructure and/or operational improvements (Palmintier, *et al.*, 2016, p. 20-23). Sections 2.2 and 2.3 describe the latest research on these issues in detail.

Finally, utilities and other critics raise questions of customer fairness. They argue that customers who own DPV systems are effectively cross-subsidized by those who do not, as the latter group

ends up paying a larger share of the fixed costs that each group needs equally (Edison Electric Institute, 2013). This leads to the claim that net-metering and other DPV incentives are regressive policies that primarily benefit wealthier customers, at the expense of others who cannot afford DPV systems (Institute for Energy Research, 2013). These arguments rely on the critical assumption that increased levels of solar PV will cause increases to base electricity rates, a question that is explored in greater depth in Section 2.1 of this report.

1.2. The Policy Debate on Distributed Solar Energy

The ongoing debate about distributed solar energy has taken place primarily at the state level, due to the fact that states have the primary authority for regulating the electric utility industry. Most states, including Virginia, have a “regulated monopoly” model in which electric utilities have the monopoly right to provide electricity within a defined service area. In exchange for this monopoly right they must seek approval from their state’s Public Utility Commission (PUC) for most major actions including rate adjustments, construction of new generation or transmission facilities, adoption of new solar energy programs, etc. In Virginia the PUC authority is held by the State Corporation Commission.

Many states across the U.S. have adopted a variety of policies and incentives to promote the deployment of DPV systems. These include personal or corporate tax credits, property or sales tax exemptions, low-interest loan programs, grant programs, renewable portfolio standards, solar renewable energy credit (SREC) markets, streamlined interconnection procedures, and net-metering laws, among others. In addition, an increasing number of states are passing legislation to enable innovative third-party ownership models for solar PV, such as solar lease programs, power purchase agreements (PPAs), and community shared solar arrangements.

The most relevant policy to this study is net-metering, the policy requiring electric utilities to purchase excess electricity from DPV systems at the standard retail rate. Net-metering exists, in one form or another, in more than 40 states plus the District of Columbia (Center for Climate and Energy Solutions, 2016). However, these 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).

Due to the concerns discussed in Section 1.1.2, electric utilities across the country have pursued a variety of policies to slow the growth of DPV, primarily through restrictions to net-metering (Tabuchi, 2017). Various bills have been proposed to increase the fixed fees applied to DPV customers, reduce the compensation for excess electricity produced by DPV systems, or in some cases scrap net-metering entirely (ClimateNexus, 2016). For example, in 2011, Virginia became the first state to allow utilities to levy monthly “stand-by charges” on customers owning net-metered PV systems. Similar policies have been adopted or considered in Arizona, Georgia, Idaho, Maine, Oklahoma, Vermont, and Wisconsin (North Carolina Clean Energy Technology Center, 2014), among other states. On the other hand, some states have taken steps to strengthen net-metering laws or otherwise expand access to DPV systems. New York, for example, has suspended a cap on net-metered systems and is pursuing efforts to “restructure utilities so they can profit from integration

of more renewable energy into the grid.” New Mexico and California are among states where efforts to weaken net-metering have been resisted (ClimateNexus, 2016).

A few of the more interesting net-metering debates have played out recently in Arizona, Hawaii, and Nevada. Arizona discontinued net-metering in December, 2016, (Shallenberger, 2016), only to replace it a few months later with a much more complicated program, developed in a compromise between the solar industry and utilities (Shallenberger, 2017b). The Nevada PUC voted in late 2015 to raise fixed fees on DPV customers and dramatically reduce the payments they receive for excess production, causing several leading solar energy firms to shut down operations in the state (ClimateNexus, 2016). Regulators later agreed to grandfather in existing net-metering customers, and restore it for some customers in the northern part of the state, while solar advocates have appealed the issue to the state courts (Ola, 2016; Shallenberger, 2017a).

In Hawaii, the sunny climate and extremely high retail electricity rates create very favorable market conditions for solar energy (Michaud, 2016). As a result, market penetration for DPV is as high as 9% to 12% on some islands. While this is generally considered good news by solar energy advocates, the state’s electric utilities claim that net metering cost them \$38 million in 2013 and \$53 million in 2014 (Trabish, 2015). Thus, in 2015, the Hawaii Public Utilities Commission approved a ruling to end its net metering program to new participants, who will instead have to choose between two tariff options which are less favorable than the prior net metering program (Pyper, 2015). The solar energy industry has publicly criticized the decision, claiming that arguments against net metering are premature until the state conducts a thorough analysis of the costs and benefits of solar PV (Trabish, 2015).

1.3. Distributed Solar PV in Virginia

1.3.1. Installed Solar Capacity in Virginia

Data from the Virginia State Corporation Commission (2018) shows that Virginia’s investor-owned and cooperative electric utilities totaled 41.5 megawatts (MW) of net-metered DPV capacity by the end of 2017, for a 44% increase from 2016 and a more than ten-fold leap from 2010. Data from the U.S. Energy Information Administration (2018b), which also includes municipal electric utilities, shows a total of 46.5 MW at the end of 2017.

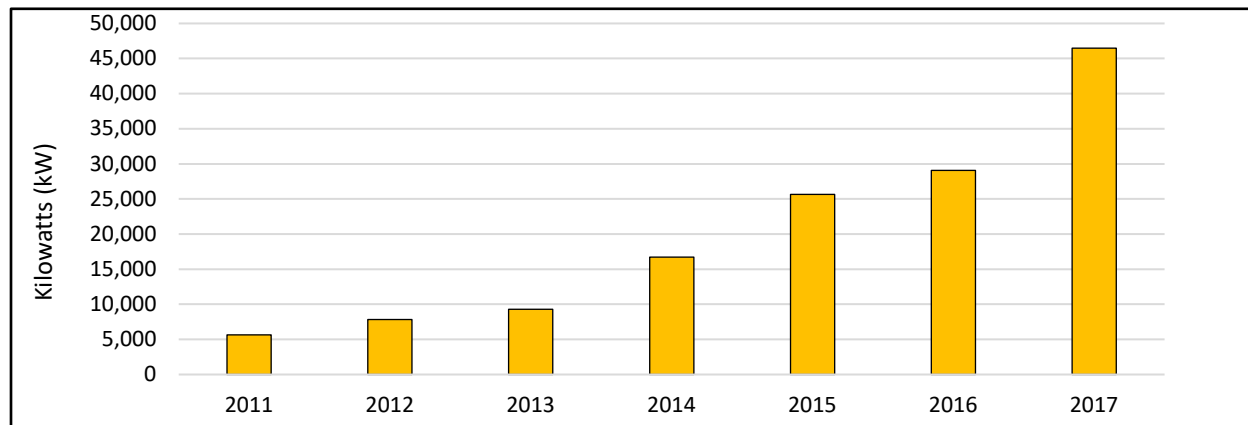
Virginia had no utility-scale PV capacity as recently as the beginning of 2016. By the end of that year, over 105 MW had been installed, with the total increasing to 369.3 MW at the end of 2017 (U.S. Energy Information Administration (2017b; 2018b). The Virginia Renewable Energy Alliance (2017) projects that an additional 376 MW will be developed in 2018.

The growth of utility-scale PV in Virginia has been driven in part by demand from the growing data center industry. For example, Dominion announced in November, 2016, that it would acquire 180 MW of PV, from five different facilities, to provide power to Amazon Web Services (Blackwell, 2016). A little less than a year later, Dominion unveiled a plan to provide up to 300 MW of solar PV to supply a new Facebook data center in eastern Henrico County (Martz, 2017).

Dominion’s partnerships with Amazon and Facebook are representative of an emerging trend in which major corporations are putting pressure on electric utilities and state regulators to provide

them with more solar energy options. For example, in November of 2016 a group of 18 major businesses, including Microsoft, Walmart, Best Buy, and Ikea, issued a letter to Virginia lawmakers and the SCC asking for new legislation and/or regulations to provide expanded renewable energy opportunities from both utilities and third-party sellers (Zullo, 2016).

Figure 8. Total Net-Metered Solar PV Capacity in Virginia, 2010 – 2017



Source: U.S. Energy Information Administration, 2018b

In addition, Virginia has seen several commercial-scale PV projects initiated under Dominion’s Community Solar Partners and Virginia Power Purchase Agreement Pilot Programs, including projects in the Richmond region at Capital One, Virginia Union University, and the University of Richmond (Dominion Energy, 2017a; Secure Futures, 2016). Other organizations, such as the Old Dominion Electric Cooperative, Appalachian Power Company, and Council for Independent Colleges in Virginia have also announced planned solar projects (Hodsoll, 2015). Finally, the BARC electric cooperative opened the state’s first “community solar” or “shared solar garden” program in August, 2016 (Jackson, 2016), and new small utility-scale systems (3-6 MW) are being installed by municipal electric utilities in the Town of Bedford, City of Danville, and Town of Front Royal (Virginia Solar Energy Development Authority, 2016; Bridges, 2017).

Much of the state’s recent progress with DPV has come in the form of various “Solarize” and “solar co-op” programs initiated by local non-profit organizations VA SUN, Community Housing Partners, the Local Energy Alliance Program, and the Richmond Region Energy Alliance. Over 40 of these programs had been initiated to date, in at least 30 different Virginia communities. Collectively, those programs installed 5.6 MW of DPV in Virginia between June, 2014, and the end of 2016, accounting for about 40% of the state’s new net-metered solar PV over that time.

Despite these recent successes, Virginia’s 46.5 MW of DPV at the end of 2017 ranked only 31st among all states, far less than neighboring Maryland (6th, with 619 MW) and North Carolina (19th, with 126 MW), but just ahead of the District of Columbia (38 MW). In addition, Virginia’s rate of 5.49 MW of DPV per million residents ranks 38th among all states. Virginia ranked better in total PV capacity (DPV and utility-scale), with its 415.8 MW registering as the 16th highest total, still behind North Carolina (2nd, with 3347 MW) and Maryland (11th, with 786 MW) (U.S. Energy Information Administration, 2018b). Only 11% of Virginia’s total installed solar energy capacity is from DPV, compared to 39% of the total nation-wide, which puts Virginia 45th among all states in that regard.

1.3.2. Estimates of Solar Potential

Despite the slow progress thus far, Virginia does have massive untapped potential for both DPV and utility-scale solar. The 2007 and 2010 versions of the Virginia Energy Plan both estimated the state's solar energy potential to be between 11,000–13,000 MW (Schlissel, Loiter & Sommer, 2013). The U.S. Department of Energy's SunShot Vision Study projects solar PV installed capacity for Virginia to be 8,700 MW by 2030 and 21,200 MW by 2050 (U.S. Department of Energy, 2012). A series of National Renewable Energy Laboratory (NREL) reports from 2008-2012 estimated that Virginia has the technical potential to install 19 GW of DPV, enough to produce approximately 2.23 million gigawatt (GW) hours of solar (Denholm & Margolis, 2008; Lopez, *et al.*, 2012), equal to about 20% of the current total annual electricity consumption in the state (U.S. Energy Information Administration, 2017d). Lastly, the U.S. Environmental Protection Agency found that up to 35 MW of solar could be installed on just 49 municipal facilities in the Metropolitan Washington Council of Governments territory in Virginia (Metropolitan Washington Council of Governments, 2013).

1.3.3. Solar Energy Policy Debates in Virginia

Compared to many other states, Virginia has relatively few incentives in place to support DPV. While it technically does have a renewable portfolio standard (RPS), this is a voluntary program that incentivizes rather than requires electric utilities to provide renewable energy (Database of State Incentives for Renewables and Efficiency, 2015c). Furthermore, the program has been criticized for setting watered-down targets that utilities can easily meet without investing in any new renewable energy generation (Main, 2016). Several proposals for a mandatory RPS have failed in recent years, including SB 761 in 2016 (Virginia's Legislative Information System, 2016). The lack of a mandatory RPS means that there is no SREC market in the state. Virginia residents were previously able to sell SRECs to utilities in Pennsylvania and the District of Columbia, but now both of those markets are closed to new Virginia participants (Rodvien, 2017; SRECTrade, 2018).

Virginia also does not offer any of the financial incentives that some other states provide for solar PV, such as cash rebates or personal or corporate income tax credits. These financial incentives are in addition to the 30% federal tax credit available to all income-tax-paying DPV purchasers through the end of 2019. The state does offer some smaller financial incentives, such as a Clean Energy Manufacturing Incentive Grant Program and an exemption from applying machinery and tools taxes to solar energy equipment (Database of State Incentives for Renewables and Efficiency, 2018a).

The state of Virginia passed net-metering legislation in 2000, codified under section 56-594 of the Code of Virginia (Database of State Incentives for Renewables and Efficiency, 2018b). However, the net-metering program includes several limitations, causing the state to receive a grade of C (on an A-F scale) from the annual Freeing the Grid report (2017) published by the Interstate Renewable Energy Council (IREC) and The Vote Solar Initiative.

First, the net-metering program limits the capacity of individual net-metered PV installations to 20 kW for residential systems and 1 MW for commercial systems. Other states have much higher NEM capacity limits (e.g., Oregon has 2 MW for commercial and 25 kW for residential), while some states have no limits whatsoever (e.g., New Jersey). Additionally, and most relevant to this study, the program also includes an aggregate capacity limit, which limits each utility service area's net-metered energy capacity (for solar PV and other distributed energy technologies) to 1% of the

utility's forecasted peak load for the previous year (Database of State Incentives for Renewables and Efficiency, 2015b).

In 2011, the Virginia General Assembly adopted House Bill (HB) 1983, which enabled Virginia utilities to pursue stand-by charges on residential systems between 10 and 20 KW. The SCC subsequently approved Dominion's request for a \$4.19/kW monthly stand-by charge (Shapiro, 2011). Appalachian Power Company, Virginia's second largest electric utility, received SCC approval for a \$3.77/kW stand-by charge in 2014 (Virginia State Corporation Commission, 2014).

To address some of the utilities' concerns, the SCC prepared reports on the impacts of net metering and distributed solar in 2011 and 2012. The 2011 study found that at existing levels of market penetration, "customer generators impose a very small net cost on Virginia's utilities in total, and such cost results in an 'immaterial' average annual bill impact on non-net metering customers" (Virginia State Corporation Commission, 2011, p. 8). The study also found that under a fully subscribed program (i.e., if installed capacity reached 1% of peak demand within each utility's service area), the average residential electric bill would only increase by \$6.73 per year (Virginia State Corporation Commission, 2011, p. 11).

In 2014, the state's Department of Environmental Quality and Department of Mines, Minerals, and Energy convened a collaborative stakeholder working group to study the costs and benefits of distributed solar energy. While this group did not have access to the data needed to conduct a true "value of solar" analysis, it did recommend a methodology by which such a Virginia value of solar study could be conducted in the future (Pitt & Michaud, 2014).

Former Virginia Governor Terry McAuliffe took several steps to express his support for solar energy and climate change mitigation (i.e., reduction of greenhouse gas emissions). In December, 2015 he announced the Commonwealth's commitment to obtaining 8% of its electricity from solar within three years (Ramsey, 2015). In February, 2016 he was one of 17 Governors to sign a bipartisan pledge to expand energy efficiency, increase solar and wind power production, modernize the electricity grid, and cut emissions (Milman, 2016). He then issued Executive Order 57, directing the Secretary of Natural Resources to convene a Work Group to "study and recommend methods to reduce carbon emissions from electric power generation facilities" (Commonwealth of Virginia Office of the Governor, 2016). This led to Executive Directive 11, which requires the Department of Environmental Quality to develop regulations to "abate, control, or limit carbon dioxide emissions from electric power facilities" (Commonwealth of Virginia Office of the Governor, 2017).

Shortly before the publication of this report, the 2018 General Assembly adopted a major overhaul of electricity regulation, the "the Grid Transformation and Security Act of 2018" (HB 1558 / SB 966). Among other provisions, the act identified rooftop PV systems of 50 kW or larger as "in the public interest," up to an aggregate capacity of 50 MW for such systems. It also created mechanisms for funding "electric distribution grid transformation projects," including advanced metering infrastructure, micro-grids, and energy storage systems, which could address some of the technical challenges associated with DPV integration (Virginia's Legislative Information System, 2018b). However, many bills failed to pass that would have directly supported the continued growth of DPV, including one (HB 393) that would have removed the 1% net-metering cap and required the state to initiate a value of solar study (Virginia's Legislative Information System, 2018a).

Determining exactly how close Virginia's utilities are to the 1% aggregate cap is a difficult proposition, due to data limitations. The SCC and DMME track all net-metered PV installations in the state's investor-owned utility (i.e., Dominion and Appalachian Power) and electric cooperative service areas, but not for the municipal electric utilities. The U.S. Energy Information Administration tracks both peak demand and net-metered distributed energy capacity, including distributed PV, across all types of electric utilities. However, their totals for Dominion and Appalachian Power include the portions of those service areas that lie in other states (NC and WV, respectively). For some cooperatives or municipal utilities the EIA does not include any net-metered PV total, either because the data is unavailable or because no net-metered PV exists in those areas. Additionally, the applicable legislation bases the cap on the utilities' forecasted, not actual, peak demands.

Table 1 below estimates each utility's net-metered market penetration (i.e., total net-metered capacity divided by peak load) for 2016, according to data from the U.S. Energy Information Administration. It is important to note that Virginia's municipal electric utilities do not fall under the authority of the State Corporation Commission, and are therefore not subject to the 1% aggregate net-metering cap. They are included in this analysis only to provide context.

The data for Appalachian Power and Dominion includes the portions of those utilities' service areas that are North Carolina and West Virginia, respectively, as no data is available on their peak demand totals exclusively within Virginia. However, their peak demand totals within Virginia can be roughly estimated using electricity sales data from their respective 2017 Integrated Resource Plans. 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, 2017b, 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 Company, 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 0.11% of the estimated Virginia peak demand for Appalachian Power, and 0.10% of the estimated Virginia peak demand for Dominion.

This data shows that the state's two large investor-owned utilities are still well below the 1% aggregate net-metering capacity cap. This is also the case with the majority of the state's electric co-operatives and municipal electric utilities. However, several of the co-operatives have much higher market penetration percentages, with BARC, Craig-Boutetourt, and the Southside Co-op already near or above 50% of the cap. Given the rapid growth of DPV, it is reasonable to think that these utilities could reach a 1% market penetration within a few years.

It is also important to note that while the 1% market penetration cap applies to all types of net-metered distributed energy systems, including small wind energy systems. Table 1 shows that DPV accounts for the vast majority of net-metered capacity in Virginia's electric utility service areas.

Table 1. Net Metering Totals and Peak Demand (MW) in Virginia Electric Utilities, 2016

Utility Name	2016 Peak Load (MW)	Total Net-Metered Capacity (MW)	Net-Metered PV Capacity (MW)	Percent of NM Capacity from PV	NM Market Penetration (NM Capacity/ Peak Load)
<i>Investor-Owned Utilities (including non-Virginia territory)*</i>					
Appalachian Power	7,363	6.68	8.00	84%	0.11%
Dominion Energy	16,914	17.46	17.62	99%	0.10%
<i>Electric Cooperatives</i>					
A & N	161	0.22	0.24	94%	0.15%
BARC	47	0.35	0.36	99%	0.75%
Central Virginia	222	0.81	0.82	99%	0.37%
Community	58	0.05	0.05	100%	0.08%
Craig-Botetourt	25	0.14	0.14	100%	0.58%
Mecklenburg	145	0.10	0.10	100%	0.07%
Northern Neck	91	0.18	0.18	98%	0.20%
Northern Virginia	1,028	2.12	2.12	100%	0.21%
Prince George	80	0.06	0.06	96%	0.07%
Rappahannock	943	3.28	2.41	74%	0.35%
Shenandoah Valley	517	1.76	1.79	98%	0.35%
Southside	267	1.27	1.27	100%	0.48%
<i>Municipal Utilities*</i>					
Bristol Virginia Utilities	125	--	--	--	--
City of Danville	229	0.07	0.07	100%	0.03%
City of Franklin	35	0.04	0.04	100%	0.12%
City of Harrisonburg	141	0.61	0.61	100%	0.43%
City of Manassas	94	--	--	--	--
City of Martinsville	38	--	--	--	--
City of Radford	41	0.04	0.04	100%	0.09%
City of Salem	81	0.11	0.11	100%	0.13%
Town of Bedford	49	--	--	--	--
Town of Culpeper	28	--	--	--	--
Town of Front Royal	45	--	--	--	--
Virginia Tech Electric	62	0.28	0.28	100%	0.45%

Notes: Municipal Electric Utilities in Virginia are not subject to the authority of the Virginia State Corporation Commission, and therefore the 1% aggregate net-metering cap does not apply to those utilities.

Sources: U.S. Energy Info. Administration, 2017c; Dominion Energy, 2017b; Appalachian Power Company, 2017

2. Emerging Issues in Distributed Solar PV

This section provides a comprehensive review of previous academic and professional research on two key issues related to the grid integration distributed solar PV: 1) “value of solar” analysis and the impacts of distributed PV on retail electricity rates; and 2) hosting capacity analysis to determine the amount of solar PV that can be effectively placed on the grid. In researching these issues we analyzed hundreds of peer-reviewed academic studies, professional and technical reports (i.e., white papers from credible energy research organizations), and relevant websites (e.g. from government agencies and non-profit groups).

2.1. Value of Solar Analysis

One of the key issues concerning solar energy in the U.S. is the debate about the financial value that solar energy may provide to utilities, ratepayers, or society as a whole. As distributed solar PV has become more prevalent in recent years, stakeholders have become further interested in examining both its costs and benefits. Some states have used these “value of solar” (VOS) studies to modify or revamp their net metering laws (Taylor, *et al.*, 2015).

Over the past decade, a wide range of academics, technical consulting firms, non-profit organizations, and state and federal agencies have tackled the VOS issue. These prior VOS studies reflect a variety of perspectives, variables, methodologies, and input assumptions. Most have been conducted on behalf of an electric utility, the solar energy industry, or a state public utility commission. In addition, several recent studies have provided overviews of VOS issues and methodologies (e.g., Barbose, 2017; Denholm, *et al.*, 2014; Hallock & Sargent, 2015; Keyes, & Rábago, 2013; Rocky Mountain Institute, 2013).

At the most basic level, VOS studies seek to quantify the benefits of solar energy in terms of the avoided costs that utilities would otherwise have to pay, including the cost of generating an equivalent amount of electricity from conventional sources (i.e., “avoided energy” costs), and avoided investments in generation, transmission, and/or distribution infrastructure. Some also quantify other 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. Some VOS studies also attempt to quantify the broader societal environmental and/or economic development benefits of solar energy, such as the benefits of avoided GHG emissions or new jobs created in the solar industry. Others include additional costs, such as the cost of establishing new billing systems for net-metered DPV customers (Hallock & Sargent, 2015). If the net value of those costs and benefits for a given utility exceeds that utility’s cost of service (i.e., its average cost of providing a unit of electricity), then solar energy can be deemed a net-positive for that utility and its customers.

Some VOS studies focus only on the direct costs and benefits of solar for electric utilities, excluding the broader environmental and economic development impacts (e.g., SAIC, 2013; XCEL Energy Services, 2013). Others, particularly those completed on behalf of the solar energy industry or pro-solar non-profit organizations, expand the analysis to include the broader societal benefits of solar energy, while sometimes downplaying its potential costs (e.g., Perez, Norris & Hoff, 2012; Perez & Hoff, 2008).

The best overview of VOS research findings comes from two meta-analysis studies completed by Environment America (Hallock & Sargent, 2015) and the Lawrence Berkeley National Laboratory (LBNL) (Barbose, 2017). The Environment America report compared eleven VOS studies completed between the spring of 2013 and spring of 2015, identifying the cost/benefit categories included in the respective analyses and the resulting final net benefit in cents per kWh. The total net benefits ranged from as low as \$0.036 / kWh, in a study completed for utility called Arizona Public Service Company (SAIC, 2013), to a high of \$0.336 in a study for the Maine Public Utilities Commission (Norris, *et al.*, 2015).

Three of the eleven studies in the Environment America report were completed on behalf of electric utilities (SAIC, 2013; XCEL Energy Services, 2013; Hoff & Norris, 2014), and these had the three lowest VOS results, from the aforementioned \$0.036 to \$0.107 / kWh. Those were also the only studies in which the VOS was found to be lower than the retail electricity rate in the given study area. The other eight studies were completed on behalf of Public Utility Commissions (PUCs) or “other, non-utility organizations” (e.g. the solar energy industry and/or pro-solar non-profit organizations). They found VOS values between \$0.116 in Utah (Norris, 2014) and \$.336 / kWh in Maine (Norris *et al.*, 2015), with no clear pattern or differentiation between the PUC vs. “other” studies. Those results for the non-utility-sponsored studies were all between roughly 45% and 125% above the retail electricity rates in their respective study areas (Hallock & Sargent, 2015).

The four studies that included avoided GHG emissions and economic development benefits had the highest results, with a minimum of \$0.281 in New Jersey (Perez, Norris & Hoff, 2012). All four included GHG benefits, with values ranging widely from \$0.022 (Perez, Norris & Hoff, 2012) in New Jersey to \$.096 / kWh in Maine (Norris, *et al.*, 2015). The only studies to include a value for economic development were those addressing New Jersey and Pennsylvania (\$.044 and \$.045 / kWh, respectively), which were originally part of the same document (Perez, Norris & Hoff, 2012) but were treated separately in the Environment America report. These four studies also tended to estimate higher values for grid resiliency and reduced financial risks (Hallock & Sargent, 2015).

The LBNL meta-analysis evaluated 19 VOS studies completed from 2012-2016, including all of those addressed in the Environment America report. Where possible, the LBNL report distinguished between results for the “core” VOS values such as avoided energy costs and generation / transmission / distribution investments, versus “core+” results that also include 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 the VOS studies it analyzed. This resulted in a balanced evaluation of direct rate-payer impacts across all 19 studies, with all resulting values adjusted to 2015 dollars (Barbose, 2017).

The LBNL analysis produced 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. Sorting the LBNL results by sponsor type, we find that the five utility-sponsored studies had significantly lower core and core+ VOS scores, on average, than the studies sponsored by PUCs or the solar industry and/or pro-solar non-profit organizations, as can be seen below in Table 2.

Table 2. Summary of VOS Results by Study Sponsor Type (\$ / kWh)

Sponsor Type	“Core” VOS		“Core+” VOS	
	Mean	Median	Mean	Median
Utility	\$0.061	\$0.069	\$0.090	\$0.184
PUC	\$0.120	\$0.138	\$0.186	\$0.175
Solar Industry / Non-Profit	\$0.140	\$0.125	\$0.163	\$0.160

Source: Barbose, 2017. Additional analysis by authors.

The LBNL report also presented the results of each study in terms of the ratio of the calculated VOS to the cost of service within each respective study area. If this ratio is less than 100%, then the value of solar is less than the cost of service, and greater solar energy use would be assumed to raise retail electricity rates. On the other hand, if the result is greater than 100%, then the value of solar exceeds the cost of service and would presumably lead to a reduction of retail electricity rates (Barbose, 2017).

These results reflected similar patterns as those discussed above for the raw VOS values. All of the utility-sponsored studies had a VOS/COS ratio of less than 100%, with the exception of the 111% core+ VOS/COS ratio found in a study for the Austin Energy municipal electric utility (Hoff and Norris, 2014). The studies sponsored by PUCs or pro-solar groups mostly had ratios close to or exceeding 100%, with several showing results well above 150%. Again, it is important to reiterate that these values, even in the core+ VOS calculation, do not include any broad societal environmental or economic development benefits (Barbose, 2017).

2.1.1. Retail Rate Impacts from VOS Analysis

Unlike any other VOS report or study, the LBNL took the additional step of using these VOS results to estimate the effect of increased solar energy use on retail electricity rates. This analysis addresses the critically important question of “cross-subsidization,” or the notion that increased solar energy capacity will provide savings to DPV customers at the expense of non-DPV customers. The LBNL study discusses the various complexities and assumptions inherent in addressing this issue, before proposing a simple and elegant approach to estimating the effect of DPV on retail electricity rates.

The model proposed by LBNL calculates the estimated percent change in retail rates as a function of four factors: market penetration (i.e., the percentage of a given utility’s customers that have installed DPV systems), the calculated value of solar, the utility’s average cost of service (COS), and the rate of compensation paid to DPV customers. The formula for this analysis is shown in Figure 9.

Figure 9. LBNL Formula for Estimating DPV Impact on Retail Electricity Rates

$$\text{Percent Change in Retail Electricity Price} = \text{Penetration} \times \left[\frac{\text{Solar Comp. Rate}}{\text{CoS}} - \frac{\text{VoS}}{\text{CoS}} \right]$$

Source: Barbose, 2017

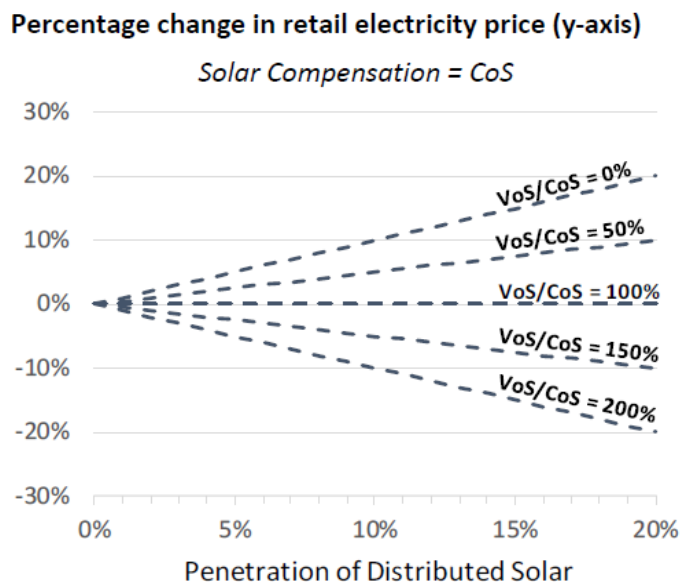
The COS rate is assumed to be equal to the retail electricity rate, which means that in most forms of net-metering the solar compensation rate is also equal to the COS rate. Thus, the formula can be simplified as the penetration rate multiplied by a value of one minus the VOS/COS ratio. This model makes intuitive sense, as for example a VOS/COS of 75% would mean that electricity produced by DPV systems is equal to three-quarters the value of conventional electricity, and any DPV customer who received full net-metering would effectively be subsidized by 25%. If one assumes that the retail rate is based on the actual COS, then each incremental increase in the DPV penetration rate would increase the retail rate accordingly. In this example, a 1% DPV penetration would result in a .025% increase in retail rates, a 10% penetration would produce a 2.5% rate increase, etc.

As noted above, the VOS/COS ratio varies greatly among the studies evaluated by LBNL. At the lowest range of those results, a “core” VOS of 31%, the formula estimates a 0.69% increase in retail rates for every 1% of market penetration. A VOS/COS of 90%, such as the core rate found in the Austin Energy study (Hoff and Norris, 2014), would increase retail rates by only 0.1% per every 1% of DPV penetration (i.e., a 10% market penetration would produce a 1% rate increase). On the other hand, a VOS/COS of above 100% would lower retail rates. For example, the core VOS of 148% calculated for the Mississippi PUC study (Stanton, *et al.*, 2014) would reduce retail rates by nearly half a percent for every 1% of DPV market penetration.

Of particular relevance to Virginia is the VOS study completed for Pennsylvania and New Jersey (Perez, Norris & Hoff, 2012). Of all the VOS studies evaluated in the Environment America and/or LBNL reports, that is the only one addressing states that, like Virginia, lie primarily within the service area of the PJM Interconnection regional transmission organization (PJM, 2017). The LBNL calculated a core VOS of \$0.075 and a core+ VOS of \$0.176 / kWh for the Pennsylvania / New Jersey study, with corresponding VOS/COS ratios of 51% and 121% (Barbose, 2017). Thus, a 1% market penetration rate would either increase retail rates by 0.49% or reduce them by 0.21%, depending on whether core or core+ VOS calculations are used.

Additionally, the LBNL report notes that DPV market penetration is extremely low in most utility service areas, with an average of 0.4% nationwide per the U.S. Energy Information Administration. As a result, the total impact of DPV on retail rates is likely to be minimal for the vast majority of utilities, regardless of the VOS calculation or the VOS/COS ratio. The LBNL study includes a chart that illustrates various possible outcomes for the retail rate price impact, assuming full net-metering, at DPV penetration rates from 0-5% (see Figure 10 below).

Figure 10. Impact of DPV Market Penetration on Retail Electricity Rates



Source: Barbose, 2017

Figure 10 demonstrates that a VOS/COS ratio of between 50% and 150% would produce virtually no discernable retail price impact at market penetration rates below 5%. Per the LBNL study, only eight electric utilities in the entire country have penetration rates that high, the top four of which are in Hawaii. All of the mainland utilities with penetration rates above 4% are co-ops and municipal utilities, and Pacific Gas & Electric (PG&E) has the highest penetration among mainland investor-owned utilities at 3.6%. The LBNL report lists a core+ VOS/COS of 98% from a study for the California PUC (Beach & McGuire, 2013), with no core-only VOS value calculated. Thus, the current rate impact of DPV in the PG&E territory would work out to an increase of 0.07%. Per this formula, it is safe to say that no major utilities, outside of perhaps Hawaii, are currently experiencing notable retail price increases from DPV.

2.1.2. Applying VOS Retail Rate Impact Formulas to Virginia

As discussed in Section 1.3.3, the Virginia SCC released a study in 2011 that evaluated the costs and benefits of DPV in the Commonwealth. The study produced two sets of results, one based on the existing amount of net-metered DPV installed at the time (4.5 MW), and another based on a future scenario in which installed net-metered DPV capacity reaches the statutory 1% limit in all electric utility service areas (234.4 MW). Both sets of calculations included values for most of the core variables typically included in VOS studies: avoided energy costs, avoided generation capacity costs, and avoided transmission and distribution system costs. However, the study did not address additional variables found in many other VOS studies, such as grid support services, financial risk, reliability risk, environmental impacts, and economic development. It also included utility-reported estimates of “incremental customer-related” costs, intended to address the cost of interconnecting DPV systems to the distribution grid as well as ongoing customer service and billing costs (Virginia State Corporation Commission, 2011).

As described above, most VOS studies add up these benefits and costs to produce a “value of solar” figure, in cents per kWh. This can be compared to the prevailing retail electricity rate to determine if the net value is positive (i.e. a VOS/COS ratio above 100%) or negative (VOS/COS below 100%). The Virginia SCC study took a slightly different approach, in that “avoided utility revenue” was included in the VOS calculation itself. This produced a negative VOS value that represented the estimated total cost to utilities per kWh produced by net-metered DPV systems.

While both the base 2011 analysis and full-capacity models demonstrated a net-negative cost to utilities from DPV, the study demonstrated that the impact of those costs on ratepayers would be minimal. In the base analysis, total net costs from DPV were calculated at \$234,932, or \$0.032 / kWh of electricity produced from DPV systems. Given the extremely low DPV market penetration at the time, equal to roughly 0.05% of total statewide peak demand (Pitt & Michaud, 2014), the estimated \$234,932 cost translated to an “immaterial” increase of thirteen cents per residential customer per year. The full-capacity model, which evaluated the impacts of increasing DPV to the 1% market penetration cap, estimated a net cost of \$0.030 / kWh of electricity produced and a total cost of \$11.55 million. This higher cost still translated to only \$6.73 per residential customer per year, or a bill increase of “less than one-half of one percent” (Virginia State Corporation Commission, 2011, p. 10-11).

The raw data and calculations from the Virginia SCC study can be entered into the LBNL formula, to produce values that can be compared to other VOS studies and extrapolated to higher market penetration levels. To begin, we can infer a traditional VOS number by simply adding up the net benefits calculated for avoided energy costs and avoided generation capacity costs, minus customer costs. This produces net benefits of \$439,444 in the base analysis and \$23,021,645 in the full capacity model, as shown in Table 3 below. Dividing by the estimated generation from DPV systems, the resulting VOS estimate is about \$0.060 in both scenarios. This is directly in line with the average “core” VOS for utility-sponsored studies evaluated in the LBNL report, per Table 2 above. This makes sense given that the Virginia SCC study excluded “core+” variables like financial risk and environmental compliance costs, as well as even some of the lower-impact “core” variables like transmission and distribution capacity savings.

Table 3. VOS Factors from Virginia SCC (2011) Report

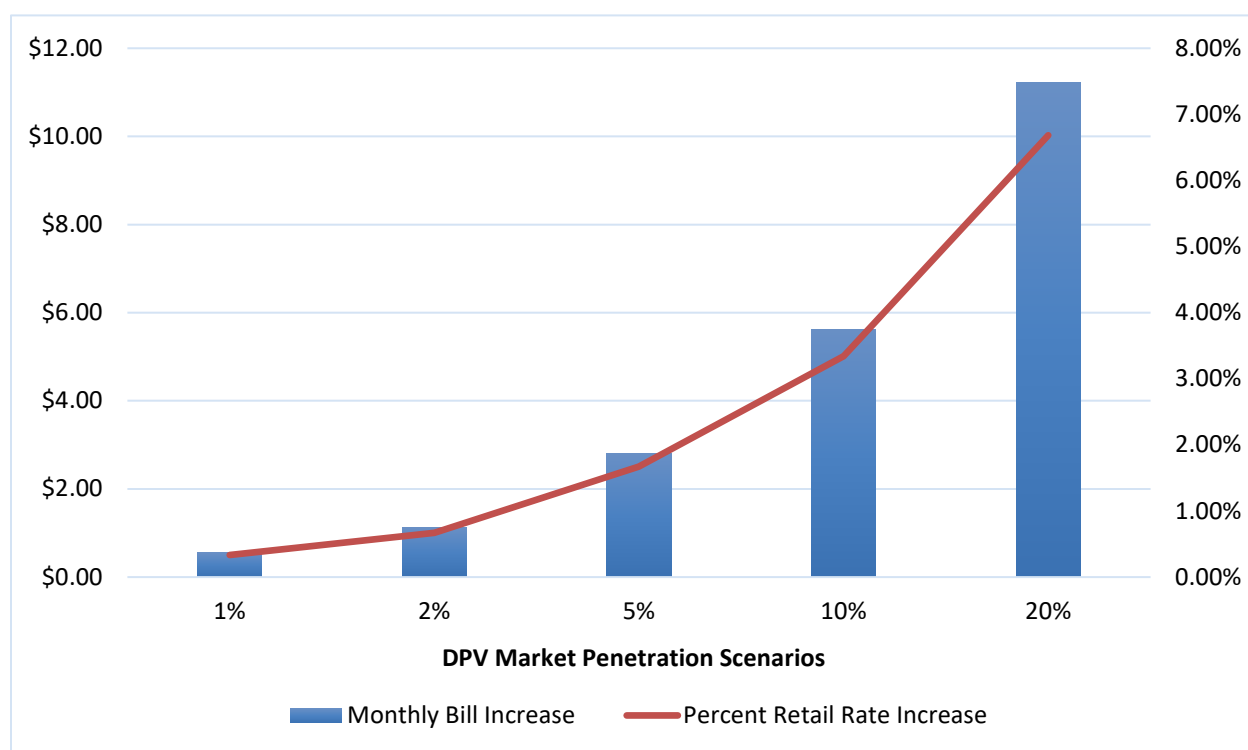
VOS Factor or Variable	Base 2011 Analysis	Full Capacity Scenario
Avoided Energy Cost	\$440,256	\$23,063,811
Avoided Generation Capacity Cost	\$94,120	\$4,891,814
Customer Costs	-\$94,932	-\$4,933,980
Net Value of Solar (total)	\$439,444	\$23,021,645
DPV Generation (kWh)	7,389,185	384,048,097
Value of Solar (per kWh)	\$0.059	\$0.060
Base Retail Rate (i.e., Cost of Service)	\$0.090	\$0.091
VOS / COS Ratio	65%	67%

Source: Virginia State Corporation Commission, 2011; Additional analysis by authors per Barbose, 2017

The Virginia SCC study estimated “lost revenue” from DPV to be about \$0.09 / kWh, based on the prevailing retail electricity rates in Virginia at the time. Using this number as the cost of service (COS) value, we get VOS/COS ratios of 65-67% for the two scenarios. Again, this is roughly equal to the “core” VOS/COS ratios for utility-sponsored studies in the LBNL report.

These numbers can then be plugged into the formula from the LBNL report (see Figure 9 above) to calculate the estimated retail electricity rate impacts at different DPV market penetration levels. Using the 67% VOS/COS ratio and 1% penetration rate from the SCC’s full-capacity model, the LBNL formula produces a retail rate increase of 0.33%, which is consistent with the “less than one-half of one percent” conclusion from the SCC study.³ If we assume that the \$6.73 annual residential bill increase calculated by the SCC corresponds to a 0.33% rate increase as calculated using the LBNL formula, then we can estimate the average residential electrical bill to be a little over \$2,000 per year or about \$168 per month. We can then extrapolate percentage increases and actual bill increases for other, higher DPV penetration rates, as shown in Figure 11.

Figure 11. Estimated Impact on Retail Electricity Rates and Residential Electric Bills in Virginia for Different DPV Market Penetration Scenarios



Source: Virginia State Corporation Commission, 2011; Additional analysis by authors per Barbose, 2017

³ One limitation of this methodology is that the SCC study measured the market penetration percentage as the installed DPV capacity divided by total peak demand within each electric utility service area, per Virginia law, while the LBNL study used the more common market penetration measurement of total DPV electricity generation divided by total retail electricity sales. However, these two measurements seem to be useful proxies for one another, as demonstrated by the fact that both approaches produced similar results for the estimated retail rate increase in a 1% market penetration scenario.

In evaluating the results in Figure 11, it is important to recall that these numbers are based on a limited calculation of only the most basic core VOS benefits, and incorporate significant assumed customer-related costs. These results are thus very conservative, in the sense that a more robust VOS study would likely produce a higher VOS value and VOS/COS ratio, given the trends identified in the Environment America and LBNL studies (Barbose, 2017; Hallock & Sargent, 2015). These higher VOS values would lead to lower estimated increases, or perhaps even decreases, to retail electricity rates and monthly residential electric bills.

Having made those caveats, the results in Figure 11 are illuminating in that they still suggest minimal increases to retail electricity rates and residential electric bills. For example, a 2% DPV penetration rate, equal to roughly a 15-fold increase of current DPV capacity in Virginia, would still increase retail rates by well under 1%, or a little over \$1 per month for the average retail electricity customer. A 5% penetration rate, well above current levels in any state other than Hawaii, would still only increase rates by 1.67% and average residential electricity bills by less than \$3 per month.

2.2. Hosting Capacity Analysis for Distributed Solar PV

A second major area of debate is the potential impact of increased DPV capacity on the electrical distribution grid. To demonstrate the extent of this concern, a survey of 31 electric utilities found that 72% “are concerned that their grids will face challenges or require upgrade[s] even before the penetration of solar PV reaches 24 percent” (Accenture, 2011, p. 13).

These technical concerns are ultimately rooted in the fact that DPV systems introduce bi-directional power flow to a distribution grid that was initially built to handle one-way flows only (St. John, 2013). Potential problems include reverse power flows, voltage variations, over-voltage and flicker, and line current overloads (Bank, *et al.*, 2013; Denholm, *et al.*, 2014; Energy Storage Association, 2016; Liu & Bebic, 2008; Smith, 2012; Zhang, *et al.*, 2012). However, the installation of new DPV capacity can also have distribution grid benefits, such as by reducing line losses and helping a utility avoid the cost of new distribution infrastructure (Cohen, Kauzmann & Callaway, 2015; Perez, Norris & Hoff, 2012).

Distribution system impacts vary greatly depending on the characteristics of individual circuit feeders and the loads that they serve. For example, DPV systems installed near the end of a feeder line segment are more likely to cause problems than those installed closer to a substation. Problems are also more likely on long feeder lines with relatively low power demand, such as in rural areas. Likewise, hosting capacity is generally lower when DPV capacity is concentrated in a few large systems, as compared to a greater number of smaller systems spread across the entire feeder (Navigant Consulting, 2016a). Grid impacts are minimized when generation occurs around the time of local demand peaks, so that most of the PV-generated electricity is consumed on-site or in nearby buildings. For this reason it can be advantageous to locate DPV in commercial districts, where daily demand peaks occur in the mid to late afternoon, closer to the time of peak PV output (Keyes & Rábago, 2013).

Other grid integration issues can arise at a broader level, when large amounts of PV reduce the net load on the generation and transmission system (i.e., the “duck curve” problem discussed in Section 1.1.2). These include the “potential curtailment of variable generation during low-load periods” and

the need for centralized generation systems to quickly ramp-up to meet evening demand (U.S. Department of Energy, 2012, p. 19).

Solar energy critics often point to Germany, arguing that the country's rapid integration of solar and other forms of distributed energy has resulted in numerous technical problems (Electric Power Research Institute, 2014). As of 2014, solar and wind accounted for 5.7% and 9.1% of Germany's electricity generation, respectively (International Energy Agency, 2017). By comparison, solar energy (utility-scale and DPV combined) accounts for only 1.4% of electricity generation in the U.S. (U.S. Energy Information Administration, 2017a). However, solar does provide a much higher percentage of electricity generation in certain states, particularly California (4.2%) and Hawaii (5.9%) (California Energy Commission, 2015; Hawaii State Energy Office, 2015). Some Hawaiian islands, including Oahu, already have PV penetration rates of 10% or higher (Wesoff, 2014). This disparity in the extent of DPV market penetration, coupled with the technology's rapid growth nation-wide, point to the need for a greater understanding of DPV hosting capacity and grid integration issues.

2.2.1. Studies of DPV Hosting Capacity and Distribution Grid Impacts

A large number of studies have sought to estimate the potential for DPV integration in the U.S. and/or individual states. Broadly speaking, they address the question of DPV integration from three perspectives: *market potential*, or projected customer demand for DPV systems under various economic and policy scenarios; *rooftop potential*, or the capacity for U.S. buildings to host DPV systems given their total roof space, orientation, shading, etc.; and *grid-potential* or *hosting capacity*, or the extent to which DPV that can be interconnected into an existing distribution grid without damaging the grid infrastructure or causing significant technical problems such as those described above.

The Department of Energy's (DOE) SunShot Vision Study, from 2012, remains arguably the most comprehensive evaluation of solar energy market potential in the U.S. As noted in Section 1.3.2, this study modeled a scenario in which average solar PV costs drop by 75% between 2010 and 2020, to \$1/watt for utility-scale PV and \$1.25 to \$1.50 / watt for commercial and residential rooftop PV, respectively. Assuming that the necessary upgrades to transmission lines and other grid infrastructure and support services could be achieved, it found that solar PV capacity could reach a total of 329 Gigawatts (GW) by 2030, and 714 GW by 2050. About 40% of PV capacity would come from distributed, or "rooftop" PV, which would reach 121 GW by 2030 and 318 by 2050. The energy produced by PV systems could provide 10.8% of total U.S. electricity demand by 2030 and 19.3% by 2050, with rooftop PV accounting for 3.5% and 5.9% respectively. Furthermore, achieving those PV capacity totals would result in "significant downward pressure on retail electricity prices" (U.S. Department of Energy, 2012, p. xxiii).

The National Renewable Energy Laboratory (NREL) has been the primary source of research on nation-wide DPV rooftop potential. In 2008, two NREL studies estimated the total potential for rooftop solar PV to be between 661 GW (Denholm & Margolis, 2008) and 712 GW, including a potential 21,837 MW in Virginia (Paidipati *et al.*, 2008). Both of these analyses were based on research that estimated 22%–27% of residential rooftop area and 60%–65% of commercial rooftop area to be suitable for solar PV systems.

A more recent NREL study used “light detection and ranging (lidar) data, geographic information system (GIS) methods, and PV-generation modeling to calculate the suitability of rooftops for hosting PV in 128 cities nationwide,” then extrapolated the results from those cities to the rest of the country (Gagnon, *et al.*, 2016, p. 2). This study found an estimated nation-wide DPV rooftop potential of 1,168 GW, enough to provide 39% of the nation’s electricity. This energy market penetration estimate varied greatly from state-to-state, from a low of 14% in Wyoming to a high of 74% in California. This study found Virginia’s estimated rooftop DPV capacity to be 28,500 MW, which translates to a market capacity penetration of above 100% (i.e., this estimated DPV capacity is higher than the estimated statewide peak demand, as discussed in Section 1.3.3). The NREL study also estimated Virginia’s DPV energy market penetration potential to be 32.4%, i.e., that DPV could provide a bit less than 1/3 of the state’s annual electricity consumption.

A separate study, conducted by GE Energy (2014b) for PJM Interconnection, estimated a much lower rooftop DPV potential in Virginia of only 3,160 MW. However, this lower total would still represent a nearly 70-fold increase over current net-metered DPV capacity, and a capacity market penetration of about 10-15% of statewide peak demand. Of this total, an estimated 13% (420 MW) could be located on residential rooftops and 87% (2,730 MW) on commercial rooftops.

Together, these market and rooftop studies indicate the potential for massive increases in our nation-wide DPV capacity. Therefore, the question of whether our distribution grids can support such DPV growth takes on even greater importance. The typical rule of thumb has been the “so-called 15% rule,” employed by the Federal Energy Regulatory Commission (FERC), which says that PV systems should be free to connect to the grid, without the need for an interconnection study, “as long as aggregate distributed generation on a feeder does not exceed 15% of its annual peak demand.” However, many studies have indicated that this may be an over-simplified approach. While many feeders, perhaps most, can support a capacity penetration far above 15%, in some cases technical problems could arise at penetrations below 15% (Hering, 2015, p. 4).

A series of update papers from the DOE, titled *On the Path to Sunshot* (2016), re-evaluated DPV’s market potential based on advances in grid flexibility, power electronics technology, and other innovations. These studies estimated that existing distribution systems could support up to 170 GW of DPV capacity, without any new infrastructure or operational changes. Further, the introduction of advanced inverters could double the potential nation-wide hosting capacity, to roughly 350 GW, allowing solar PV to provide up to 25% of the nation’s electricity by 2050.

Perhaps the most rigorous national-scale hosting capacity study was conducted in 2015 by the Electric Power Research Institute (EPRI), in coordination with the DOE and over a dozen utilities. The researchers used hundreds of monitoring systems to evaluate hosting capacity potential on 35 distribution feeders across the country. They found that feeder-level hosting capacity varied greatly, from less than 10% in some cases to over 100% in other cases (Hering, 2015).

Some of the more high profile hosting capacity studies have been regional in scope. For example, GE Energy’s Western Wind and Solar Integration Study (2010) investigated the impacts of up to 30% wind energy and 5% solar energy penetration on the power system in Arizona, Colorado, Nevada, New Mexico, and Wyoming. In this scenario, 30% of the solar energy would be from DPV, with the rest provided by concentrating solar power (CSP) plants. The study found that such renewable

energy penetration would not require extensive infrastructure changes, but would require substantial coordination among utilities on matters such as sub-hourly scheduling and improved wind and solar forecasting (GE Energy, 2010; National Renewable Energy Laboratory, 2017b).

GE Energy (2014b) also conducted the aforementioned similar study for the PJM Interconnection region, which includes Virginia and other parts of the Midwest and Mid-Atlantic. They concluded that, with adequate expansion of transmission infrastructure and “additional regulating reserves,” the region would “not have any significant issues operating with up to 30% of its energy provided by wind and solar generation” (p. 6-7). This was the case for three scenarios in which roughly 5.5% of power capacity was provided by DPV (16.9 GW), and another in which DPV accounted for 8.9% (33.8 GW). All of these scenarios resulted in lower fuel costs, operations and maintenance costs, and Locational Marginal Prices throughout the PJM region (GE Energy, 2014c).

Most hosting capacity studies have been conducted at the state level, or for a specific utility service area or grid management region within a given state. Three such studies have been conducted in California. First, a study for the California Public Utilities Commission conducted hour-by-hour comparisons of load vs. PV generation potential for each of the 1,800 electricity sub-stations in the state’s investor-owned utility service areas. The authors found that up to 15,000 MW of DPV could be accommodated, equal to about 30% of peak demand capacity, without creating reverse power flows or requiring curtailment of solar generating potential. The study did not evaluate the interconnection or ancillary services costs that would be required to achieve that level of market penetration (Energy and Environmental Economics, 2012).

A subsequent California study, funded by five of the state’s largest electric utilities, sought to identify the operational challenges that would result from providing 50% of the state’s electricity from renewable resources by the year 2030. In all six modeled scenarios, customer-owned, net-metered DPV would provide about 10,500 GWh of electricity, or about 3.5% of projected state-wide demand. Each proposal also involved varying levels of utility-owned rooftop and small-scale ground-mounted DPV, meeting up to 15.3% of state-wide electricity demand (around 44,500 GWh). The study finds the primary operational concern to be over-generation, requiring curtailment of up to 9% of the energy produced by renewable resources in the worst-case scenario. It does not identify any other specific grid integration challenges that would arise (Energy and Environmental Economics, 2014).

Yet another study simulated distribution grid impacts in Northern California, within the Pacific Gas & Electric territory. It found that “distribution-level economic impacts” would be “on average very small, and slightly positive” at a variety of solar PV capacity penetration levels, and that reverse power flows would occur no more than 1% of the time at up to 50% capacity penetration (Cohen, Kauzmann, & Callaway, 2015, p. 7, 17).

Other recent state-level studies have found hosting capacity levels to be quite high, and/or grid integration costs to be reasonably low, albeit with occasional caveats:

- A study by Argonne National Laboratory, for Arizona Public Service, investigated the grid integration impacts of various solar PV scenarios. In the “low-PV” scenario, with an estimated 8.8% of the utility’s annual energy supply provided by solar power (both utility-scale and DPV), grid integration costs would be \$1.88 per MWh of electricity produced by

solar PV (or less than 0.02 cents per kWh). In this scenario, 2.9% of renewable energy production from solar and wind would have to be curtailed (the study assumed a wind energy penetration of 4.9% for all scenarios). Under two “high-PV” scenarios, solar could provide around 14-17% of the utility’s energy, with integration costs between 0.17 and 0.38 cents per kWh, depending on the availability and flexibility of nuclear power to complement the solar PV generation (Mills, *et al.*, 2013).

- A study for the Minnesota Department of Commerce investigated the state’s RPS goal to acquire 40% of its electricity from wind and solar PV energy by 2030. It found that such energy penetration could be “successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy,” assuming “sufficient transmission mitigations” (GE Energy, 2014a, p. 1-6). These scenarios involved solar energy penetration up to 4.64%, with the majority of the state’s renewable resources coming from wind power.
- Another study found that various combinations of wind and solar could provide 30% of electric power capacity in the New York Independent System Operator territory, assuming an 80% flexible grid, without adding storage capacity and with curtailments of less than 3% (Nikolakakis and Fthenakis, 2011).
- A Texas study found that a flexible grid system could handle up to a 50% of variable renewable energy penetration, including 15% from solar, with minimal curtailments. With sufficient storage capacity (enough to provide four hours of average system load), the total variable renewable generation could reach 80% (Denholm and Hand, 2011).

While the details of these studies’ methodologies, assumptions, and findings vary greatly, they collectively demonstrate that most distribution service areas should be able to easily accommodate at least 5% DPV penetration, if not much higher.

2.2.2. DPV Grid Integration in Virginia

The most notable studies of solar energy grid integration in Virginia were completed by Navigant Research, on behalf of Dominion Virginia Power, in 2016. Collectively titled the “Virginia Solar Pathways Project,” these studies were funded by a grant from the U.S. Department of Energy’s Office of Energy Efficiency and Renewable Energy, and were supplemented by a third study conducted by the National Renewable Energy Laboratory.

The first Virginia Solar Pathways study included a review of best practices for distributed solar integration, plus a distribution-level hosting capacity study, the goal of which was:

“to determine critical levels of solar capacity that can be installed on DVP’s distribution feeders without significant impact and the need for associated distribution system upgrades (e.g., reconductoring lines, converting single phase circuits to three phase) to mitigate impacts (e.g., overvoltage, thermal overloading). (Navigant Consulting, 2016a, p. 11)

To conduct this study, Navigant analyzed the characteristics of Dominion’s 1,800 distribution feeders in Virginia and divided them into 11 “clusters.” Each cluster consisted of a group of

anywhere from 21 to 358 feeders that shared similar values across 11 key feeder variables, such as voltage, mileage, load, customer count, percentages in each customer class (residential, commercial, industrial), etc. They then selected a “representative feeder” from each cluster for further analysis (p. 14-17).

Navigant then estimated the potential DPV capacity for each census tract in Dominion’s territory, based on a weighted analysis of customer load, home values, and average incomes. This methodology produced a higher concentration of potential DPV capacity in areas of the state with higher incomes and home values, such as the areas around Richmond and in Northern Virginia, which was consistent with existing trends of net-metered DPV distribution. Navigant used these tract-level estimates to allocate potential DPV capacity to each transmission zone in Dominion’s Virginia service territory, then to individual representative feeders within those zones, then to specific “feed-in” points on those feeders. This modeling approach was similar to the methods that Dominion uses for its own internal distribution analyses (p. 11).

These processes provided the necessary data for Navigant to conduct both steady-state and dynamic analyses of DPV hosting capacity across the distribution system, and to identify “system upgrades and mitigation solutions that are needed once critical solar capacity threshold levels have been identified.” This analysis was conducted “in accordance with [Dominion] planning and operating standards and evaluation criteria” (p. 23). As a final step, Navigant also analyzed the potential hosting capacity benefits of “emerging technologies such as energy storage systems, low-voltage regulators, and smart inverters” (p. 12).

Navigant identified some important limitations of this approach:

“Feeder modeling focuses on the date and time of system peak solar output (typically during July at noon), and loading on each representative feeder at this date and time, which ranged from 30% to 60% of the feeder peak. Therefore, this analysis represents a spot check of anticipated forward-looking conditions as opposed to a full analytical assessment of all possible states or eventualities” (p. 23).

One of Navigant’s key findings addressed the level of DPV penetration that would begin to incur distribution system upgrade costs. These results are difficult to compare to other hosting capacity studies, in that they define solar penetration in terms of the amount of DPV capacity on a given feeder divided by that feeder’s “thermal rating.” The thermal rating of a feeder is the maximum amount of current that the line itself can sustain “before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements” (North American Electric Reliability Corporation, 2017, p. 29).

Navigant’s analysis found that most of the representative feeders incurred no upgrade costs at DPV penetration levels up to 50% of their feeder thermal rating. The two feeders that incurred costs at less than 50% each had “significant lengths of low-voltage sections (13.2 or 4.16 kV), plus single-phase lines, and are generally more lightly loaded per mile” (Navigant Consulting, 2016a, p. 30). To put this in perspective, one of those feeders (identified as representative feeder #11 in the study) still required no costs at up to 7.5 MW of DPV penetration, 25% of its feeder thermal rating (p. 28). In other words, a single feeder with known structural challenges (i.e., the lengths of low voltage, etc. noted above) could still sustain at least 7.5 MW of DPV without requiring any upgrades. Thus,

the hosting capacity of that single feeder with known structural challenges is equal to more than 16% of Virginia's total state-wide net-metered DPV capacity as of the end of 2017.

While the Navigant study does not directly provide an estimated DPV hosting capacity for the entire Dominion Virginia Power distribution network, it does provide sufficient findings for such an estimate to be inferred. Each of the 11 representative feeders is selected to represent a "cluster" of anywhere between 21 and 358 similar feeders across the network, for a total of 1,557 feeders. The Navigant study identifies "hosting capacities for each of the representative feeders" that range from 0 – 30 MW per feeder. Together, these 11 representative feeders could host over 200 MW of DPV just by themselves, or more than four times Virginia's total state-wide net-metered DPV capacity as of the end of 2017.

Extrapolating the hosting capacities of these representative feeders to the rest of the feeders in the Dominion service area produces an estimated system-wide hosting capacity that far exceeds the amount that would be allowed under the statewide 1% net-metering cap. For example, representative feeder #11 is assigned a hosting capacity of 7 MW, which would be a conservative estimate given the finding that it could sustain at least 7.5 MW of DPV without requiring any upgrades. Nevertheless, assuming that hosting capacity of 7 MW for Feeder #11 suggests that the 81 feeders it represents could host a total of 567 MW of DPV. Repeating this process for the other ten feeders produces an estimated system-wide hosting capacity of above 23,000 MW, a bit less than the 28,500 MW of rooftop DPV potential estimated by NREL (Gagnon, *et al.*, 2016).

While these results clearly indicate that distribution system hosting capacity should not be considered a limiting factor for DPV at the macro level, individual problems can still occur with some feeders under certain conditions. Indeed, two of the 11 representative feeders in Navigant's analysis had a hosting capacity of 0 MW. Navigant's discussion of the results notes that distribution system impacts and integration costs "are higher for larger units in a few locations, compared to many smaller units distributed evenly across the entire feeder" (p. 40), and that feeders operating at higher voltage can accommodate higher levels of DG than those with lower voltages or with low-voltage segments.

Navigant also noted that high levels of DPV capacity can cause voltage performance issues under "non-steady-state conditions," which led them to include a supplemental dynamic analysis to "study short-term impacts and changes in solar output over short time intervals, to better understand the impact of variable solar output on feeder voltage" (p. 32). This analysis looked at operational and power quality issues on three of the representative feeders and found that "hosting capacity... decrease[s] and system upgrade costs increase when dynamic impacts are considered" (p. 41).

A second study by Navigant Consulting (2016b) examined potential impacts of increased utility-scale solar and DPV on Dominion's generation and transmission networks, specifically how it "may affect grid stability, operability, and reliability for DVP's system" (p. 1). Navigant considered multiple different levels of future solar energy capacity, from 500 MW to 6,000 MW, each of which was modeled under three scenarios: all DPV, all utility-scale solar, and a hybrid scenario in which solar capacity is split evenly between DPV and utility-scale.

This second Navigant study concluded that Dominion could integrate up to at least 1,600 MW of solar PV capacity (the amount indicated on “Plan A” of its 2015 Integrated Resource Plan), “with few system upgrades on its transmission and generation system.” At this level, the modeling results indicated “few, if any thermal and voltage violations,” and noted that “many violations at these levels can be addressed by adjusting equipment settings or making modest investments in voltage controls.” In addition, the study estimated that the displacement of conventional generation by solar would result in energy cost savings of \$75 / MWh (\$0.075 / kWh) at up to 2,000 MW of solar penetration, and \$70 / MWh at 6,000 MW (p. 46-47).

However, Navigant did identify some potential grid integration impacts at higher penetration levels, such as thermal overloads in the 6,000 MW hybrid case. It also noted that “the cost of connecting solar, including protection, communications and controls, may be substantial even where system upgrade costs are low” (p. 46). Ultimately, Navigant concluded that the “critical level of solar capacity” for transmission impacts, or “the point beyond which upgrades are needed to relieve line overloads and overvoltage conditions,” can “be assumed to range between 2,000 and 4,000 MW” (p. 35). In terms of impacts to the generation system, Navigant defined this critical level as the point “at which fuel and operating cost savings significantly decline or when solar displacement of conventional generation causes violations of generating operating limits” (p. 44). Beyond this point, solar production would have to be curtailed. The study results suggested that this point of criticality for the generation system would not occur until “solar capacity exceeds 8,000 MW or about 40 to 50% of the DVP zonal peak” (p. 44).

3. Research Phase I: Estimating DPV Capacity and Energy Production Potential at the Distribution Grid Scale

Our study contributes to the broader research on distributed solar energy by modeling DPV capacity and the potential impacts of DPV on an individual sub-station-level distribution grid in Virginia. This section of our report describes our process for defining the study area and estimating potential rooftop DPV capacity for every building within the study area. It also presents those results in terms of total DPV capacity and estimated solar energy production potential, broken-down by building type (residential, small commercial, and large commercial / industrial). Most of the work described in this section was completed by faculty and staff in the Urban and Regional Studies and Planning program at VCU, referred to here as the “planning team.” The next section of this report describes our work to build a hypothetical electrical distribution model for the study area and evaluate the impacts from various levels of DPV market penetration on that distribution grid. The majority of that work was done by faculty and staff in the Electrical and Computer Engineering department at VCU, referred to here as the “engineering team.”

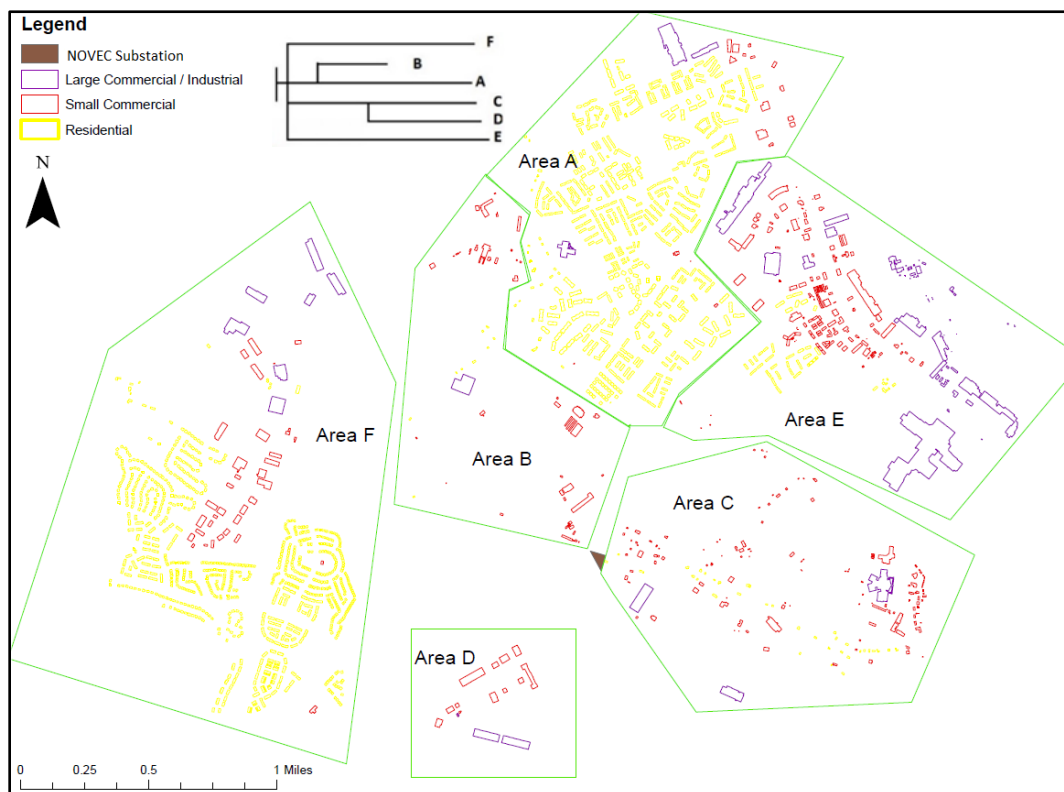
3.1. Building the Model Sub-Station Service Area

The study area for this project was intended to represent a local distribution grid served by a specific electrical sub-station outside of Manassas, Virginia, operated by the Northern Virginia Electric Cooperative (NOVEC). NOVEC provided our research team with real data on the sub-station’s hourly load profile for the year 2015, which had a summer peak demand of 23,260 kW. They also provided real data on the customer base served by that station, which included 1429 residential, 396 small commercial, and 76 large commercial / industrial customers, for a total of 1901 customers.

For security reasons NOVEC could not provide specific information on which individual buildings are served by the sub-station, or how the various distribution feeders and branch lines coming from that sub-station are aligned. In order to approximate the study area served by the sub-station, the planning team obtained geographic information systems (GIS) database layers from Prince William County. This data identified all properties and structures within the surrounding area, including information on how those properties are currently used (e.g., as an office, residence, etc.). We drew a preliminary study area boundary around the sub-station, and through an iterative process re-drew the boundary until it captured a collection of buildings around the sub-station that perfectly matched the sub-station’s actual customer base according to the NOVEC data. Thus, our model includes the exact same number of residential, small commercial, and large-commercial / industrial buildings served by the sub-station, all of which lie within a reasonable perimeter of the sub-station itself, many if not most of which are presumably served by the sub-station’s distribution feeders. However, we do not know the extent to which our study area identifies the exact buildings that the sub-station actually serves.

Using this base map, the engineering team identified a logical alignment of distribution feeders and branch lines that could serve all of the buildings in the study area. We then divided the study area into six sub-areas representing the buildings served by each feeder. The hypothetical distribution feeder alignment and corresponding study-area sub-regions are shown in Figure 12 below.

Figure 12. Base Map of Study Area and Modeled Distribution System Sub-Areas



We then determined the distribution of buildings within each sub-area by customer class, as shown in Table 4 below.

Table 4. Distribution of Study Area Buildings by Sub-Area and Customer Class

Building Type	Area A	Area B	Area C	Area D	Area E	Area F	Total
Residential	523	9	37	0	45	815	1429
Small Commercial	19	52	131	13	145	36	396
Large Comm. / Industrial	3	1	3	3	59	7	76
Totals	545	62	171	16	249	858	1901

Two of the sub-areas (A and F) are primarily residential, while two others (B and D) are primarily commercial. The remaining two areas (C and E) have a mix of residential and commercial buildings, with the vast majority of large commercial / industrial buildings found in sub-area E.

3.2. Determining Building-Specific Solar Insolation and Solar PV Production Potential

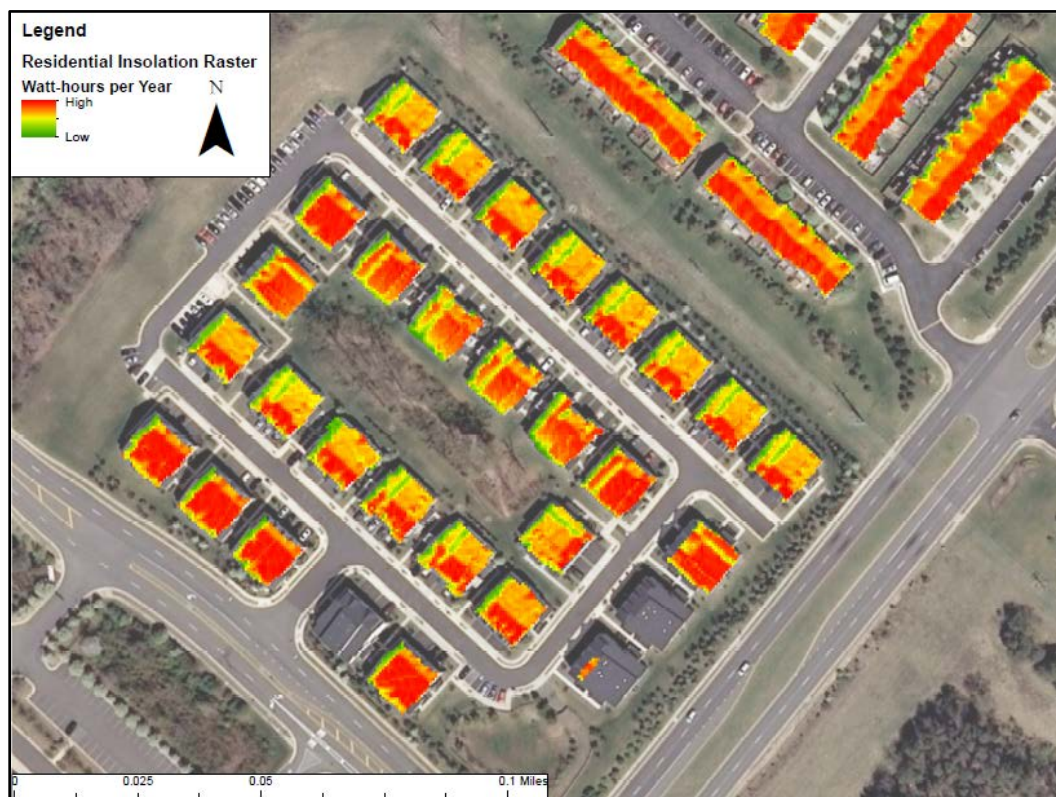
The first step in estimating DPV capacity within the study area was to gather data on the amount of sunlight that the study area receives, on average, over the course of a year. Average annual sunlight is measured in terms of incident solar radiation, or “solar insolation.” These solar insolation values can be expressed in a variety of units, but for solar PV analysis it is typically measured in kilowatt-

hours per square meter per day. The average annual solar insolation for northern Virginia is roughly 4.6 kWh/m²/day (National Renewable Energy Laboratory, 2017a). This means, for example, that a 10 m² solar PV array, with zero shading or obstructions, could expect to receive the equivalent of 46 kWh of energy from sunlight per day, on average over the course of a year. Assuming a standard efficiency of about 18%, and a 25% de-rating factor (to account for conversion from DC to AC power and other system losses), the panels would produce an average of 2,267 kWh per year, calculated as follows: 10 m² x 18% efficiency x 4.6 kWh/m²/day x 365 days x 75% de-rating = 2,267 kWh).

The planning team began this analysis by obtaining LiDAR (light detection and ranging) elevation source data from the US Geological Survey’s “The National Map” download manager service (U.S. Geological Survey, 2016). This data comes in the form of CVS point files, which we converted into a raster file in ArcGIS. Once the LiDAR data was in raster form, we used the ArcGIS “Area Solar Radiation” tool to convert that data into a solar insolation raster, which is effectively a “heat map” showing the relative solar insolation values in the study area on a spectrum of green (less sunlight) to red (more sunlight). We then “clipped” this solar insolation raster data to the building footprint data from Prince William County, which allowed us to calculate unique average annual solar insolation values for each building in the study area.

Given that these raster values stem from the LiDAR elevation data, they provide a fine-grained level of detail that takes into account shading from trees and other obstructions. For buildings with pitched roofs, the process also reflects that south-facing surfaces have higher average insolation values than north-facing ones, as can be seen in Figure 13 below.

Figure 13. Solar Insolation Raster Values in Study Area Neighborhood



We then created a new GIS layer in which the solar insolation raster was converted to “point” data, which calculated average annual solar insolation values for discrete 1 m^2 blocks atop each building. This point data was intended to demonstrate the solar energy potential for solar PV panels placed in those locations. However the initial solar insolation values calculated for those blocks assumed a flat surface, and were thus lower than the insolation that would be received by panels that are properly tilted to maximize average annual solar energy exposure. At Virginia’s latitude, a PV panel that is tilted at a 30-45 degree angle will receive about 15% more annual solar insolation, on average than a panel in the same location that is laying flat. We therefore calculated a new field in the insolation point file that raised the insolation values by that amount, thus more accurately demonstrating the potential output of a PV panel installed in that location.

The next step was to identify buildings where it would be feasible and cost-effective to install a PV system. We began this process by extracting all of the insolation blocks with above-average values (i.e., an average annual daily insolation above $4.6 \text{ kWh/m}^2/\text{day}$). This threshold produced clearly discernable patterns of high-insolation points, as shown in Figures 14 and 15 below.

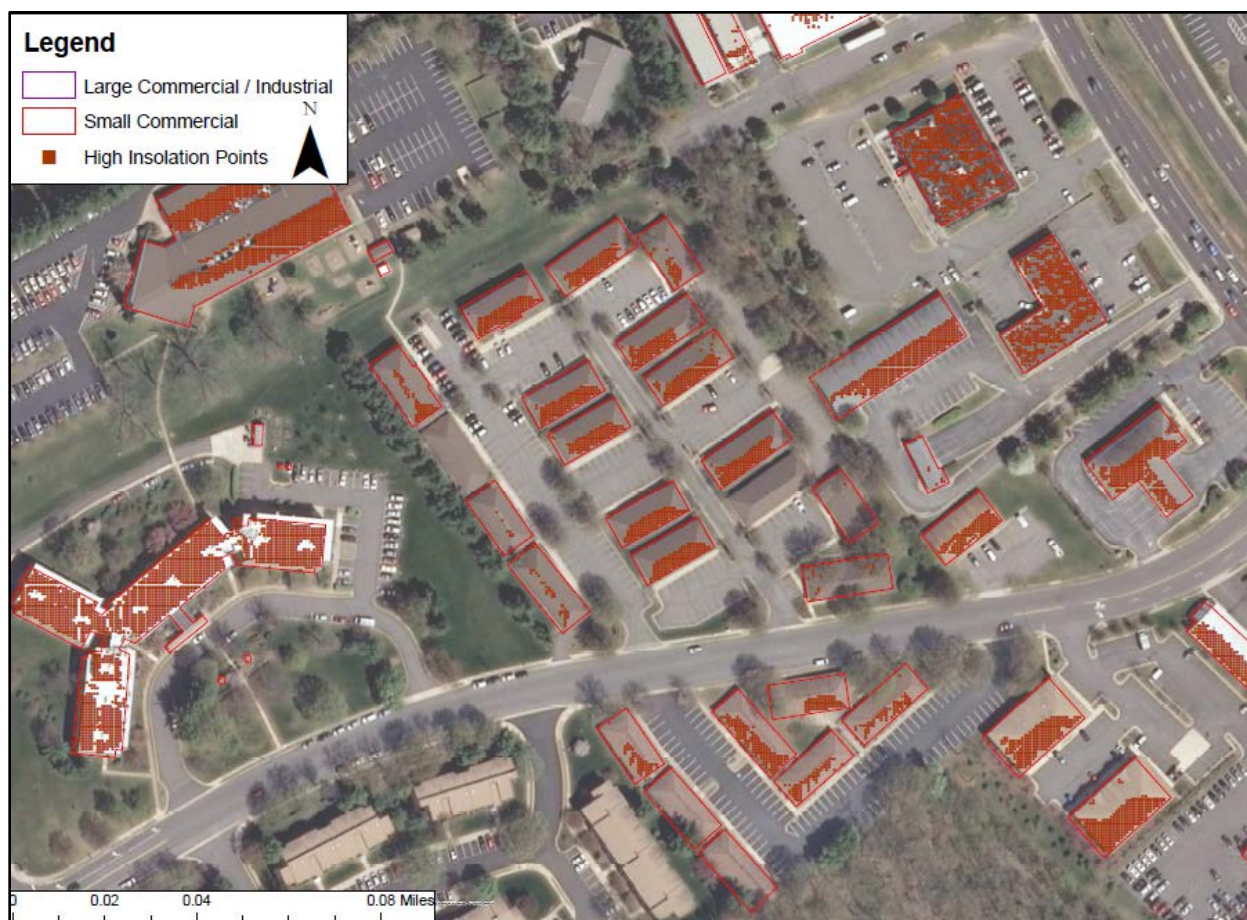
Figure 14 focuses on a residential neighborhood in the study area, and shows that the higher-insolation points are clustered on unobstructed south-facing surfaces, as would be expected.

Figure 14. High-Insolation Points in Sample Residential Neighborhood



The commercial districts in the study area are mostly devoid of trees and other obstructions, and the majority of the buildings in those districts have flat roofs. Therefore many of the buildings in commercial districts have large clusters of high-insolation points. The exceptions are those that are neighbored by taller buildings to the south, or that have an abundance of HVAC and/or other mechanical systems on their roofs, which leads to a more spotty pattern of high insolation points. These effects can be seen in Figure 15 below.

Figure 15. Solar Insolation Point Values in Sample Commercial District



We then calculated the percentage of each building that is covered with those high-insolation points, and divided the buildings into three categories based on their density of high-insolation coverage, using “natural breaks” in the distribution of those percentages, as shown in Table 5.

Table 5. Criteria for Defining Low, Medium, and High-Insolation Buildings in Study Area

Building Type	Percent of Building Coverage with Insolation above 4.6 kwh/m ² /day		
	Low	Medium	High
Residential	0 – 15%	16 – 33%	34% or above
Small Commercial	0 – 15%	16 – 33%	34% or above
Large Commercial / Industrial	0 – 25%	26 – 40%	41% or above

Figure 16 shows the distribution of low, medium, and high-insolation buildings within a selected neighborhood of single-family attached housing. The map demonstrates that the buildings with minimal shading and east-west orientation (i.e., those with south-facing rooftops) are more likely to be designated as high-insolation in this methodology.

Figure 16. Sample of Low, Medium, and High Insolation Buildings in Study Area



3.3. Estimating Total Solar PV Capacity and Electricity Production Potential

The final steps of this phase of the research were to identify the total potential DPV capacity that could be installed on buildings in the study area, and to then calculate the share of total study area electricity demand that those DPV systems could provide.

To estimate total DPV capacity, we first assumed that solar energy systems would only be installed on buildings that fall into the “high-insolation” category as identified in Table 3. This meant that 510 of the residential buildings (36%), 119 of the small commercial buildings (30%), and 26 of the large commercial and industrial buildings (34%) would be eligible for DPV.

We then assumed that DPV would only be installed on the high-insolation points of those high-insolation buildings (e.g., as shown in Figures 14 and 15 above). We calculated the average value of all of the high-insolation points on each high-insolation building, which we then used as the assumed average annual insolation for a DPV system on that building. The average values for each building category were 4.89 kWh/m²/day for residential buildings, 4.74 kWh/m²/day for small commercial buildings, and 4.68 kWh/m²/day for large commercial and industrial buildings.

This allowed us to calculate the potential installed DPV capacity for each of the high-insolation buildings, and resulting solar energy production potential, based on the following assumptions:

- DPV systems would be installed on 50% of the surface area covered by high-insolation points on high-insolation buildings
- Each DPV system would have an average efficiency of 18%
- Potential DPV system capacity is the product of the surface area on which DPV could be installed times the efficiency, as follows: $PV_{DC} = 1 \text{ kW} / \text{m}^2 \times \text{Area (m}^2\text{)} \times \text{Efficiency}$
- The potential solar energy generation for each building can be calculated using the following formula: $\text{Energy (kWh)} = \text{installed } PV_{DC} \times 0.75 \text{ de-rating} \times \text{building insolation value} \times 365 \text{ days}$

We then aggregated the resulting values per building to determine the total potential installed solar DPV capacity and electricity generation in the study area, by building type category. These results are shown in Table 6.

Table 6. Solar PV Capacity and Electricity Production Potential by Building Type

Building Type	Potential Solar PV Buildings	Average Potential PV Coverage (kW DC)	Total Potential PV Coverage (kW DC)	Share of Potential PV Coverage	Total Potential Energy (MWh)
Residential	510	17.56	8,953	36%	11,979
Small Commercial	119	58.76	6,993	28%	8,998
Large Comm. / Ind.	26	341.69	8,884	36%	11,332
Total	655		24,830		32,310

This analysis found the total rooftop DPV capacity in the study area to be just under 25 MW. Both the residential and large commercial / industrial sectors could host about 36% of this total DPV capacity, with the remaining 28% in the small commercial sector. The average size of potential DPV systems ranges from 18 kW in the residential sector to almost 342 kW in the large-commercial / industrial sector. The 18 kW average in the residential sector is much larger than would be found on a typical single-family home, due to the fact that the study area includes a number of much larger residential apartment buildings (as shown in Figures 13 and 16).

The total potential DPV capacity of 24,830 kW is equal to 107% of the total sub-station area peak load. The potential annual energy production of 32,310 mWh is equal to 28% of the annual energy demand of 114,758 mWh for the entire sub-station service area. These figures indicate that a substantial portion of the study area's electricity demands could be met through local distributed solar power, assuming that distribution grid impacts could be mitigated. Furthermore, the potential rooftop DPV capacity in just this study area is equal to more than half of the current state-wide DPV total in all of Virginia, as of the end of 2017.

It is important to note that these findings are the result of a very conservative assessment of potential DPV capacity in the study area. In short, we assumed that DPV would only be placed on buildings where a high percentage of the rooftop surface area had above-average solar insolation, relative to the Virginia average. We also assumed that only 50% of the above-average insolation surface area on those high-insolation buildings would be covered with PV panels. This methodology places PV on only 10% of residential rooftop space, 14% of large commercial and industrial rooftop space, and 16% of small commercial rooftop space. By comparison, the National Renewable Energy Laboratory study that estimated Virginia's total rooftop solar potential to be 21,837 MW estimated that 22%–27% of residential rooftop area is suitable for PV systems, along with 60%–65% of commercial rooftop area (Paidipati *et al.*, 2008). In addition, the 25% de-rating factor included in our calculations of potential solar energy production is quite conservative.

4. Research Phase II: Modeling DPV Hosting Capacity on Distribution Grid

The next step in our research was to examine the potential to maximize DPV market penetration within the study area, with minimal negative grid impacts, by placing DPV systems in optimal locations across the electrical distribution network. We began by using the data on local building stock and rooftop DPV potential to build a hypothetical electrical distribution model for the sub-station service area. We then modeled the impacts that various levels of DPV penetration would have on this hypothetical distribution grid, looking specifically at the resulting system-wide energy losses and voltage deviations.

4.1. Building the Electrical Distribution Grid Model

The first step in building the distribution grid model was to divide the findings for total DPV capacity and solar energy production potential in the study area into DPV values for each of the study area sub-regions, as shown in Table 7.

Table 7. Solar PV Capacity and Electricity Production Potential by Grid Sub-Region

Sub-Region	Potential Solar PV Buildings	Average Insolation kWh/m ² /day	Avg. Potential PV Coverage (kW DC)	Total Potential PV Coverage (kW DC)	Share of Potential PV Coverage	Total Potential Energy (MWh)
Area A	287	4.88	14.93	8,136	33%	10,770
Area B	19	4.74	29.23	1,812	7%	2,330
Area C	18	4.77	2.40	411	2%	544
Area D	16	4.67	146.08	2,337	9%	2,987
Area E	84	4.78	20.45	5,093	21%	6,549
Area F	231	4.89	8.20	7,040	28%	9,129
Total	655	4.86		24,830		32,310

The next step was to estimate the energy demands of each individual building within the study area, in terms of both their total annual energy consumption and their hourly power demand curves. The hourly demand curve assumptions were based on simulated hourly load profile datasets for residential buildings and 16 different types of commercial buildings, available from an organization called OpenEI (OpenEI.org, 2013; 2017). The planning team used the Prince William County GIS data, which included a “use code” for each parcel, and aggregated the uses reported by the county into the categories from the OpenEI dataset. Where necessary, we used Google Earth to ascertain the use of individual buildings. We created two additional categories for manufacturing and repair garages, two business types that are common to the study area but not included in the OpenEI dataset. This resulted in a distribution of all commercial and industrial buildings across 18 categories of business types, as shown in Table 8.

Table 8. Distribution of Commercial and Industrial Building Types

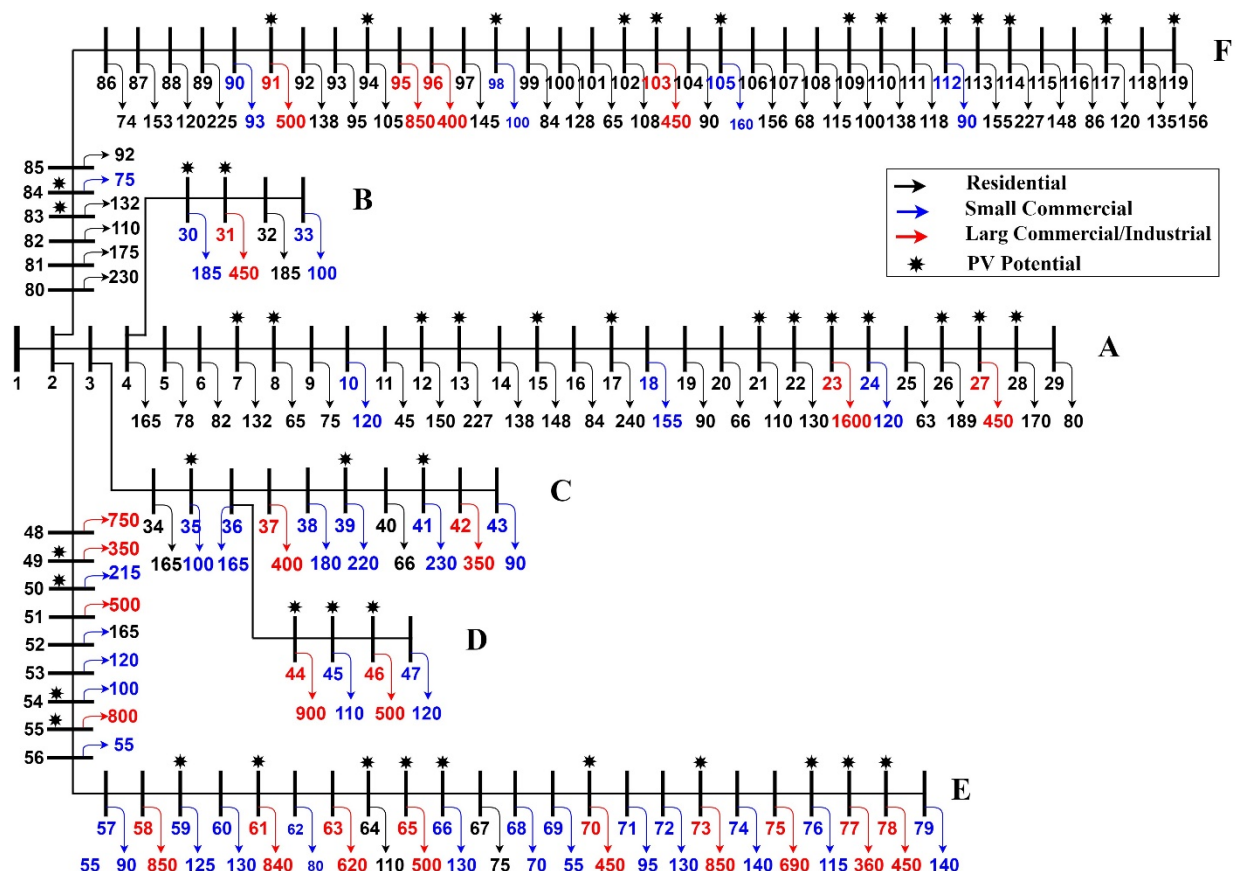
Building Type	Area A	Area B	Area C	Area D	Area E	Area F	Total
Large Office	0%	0%	0%	0%	1%	0%	0%
Medium Office	6%	4%	7%	0%	2%	5%	4%
Small Office	17%	28%	36%	8%	38%	16%	29%
Warehouse	0%	36%	9%	0%	2%	28%	11%
Stand-alone Retail	11%	0%	0%	23%	18%	14%	12%
Strip Mall	22%	0%	2%	31%	24%	14%	16%
Primary School	6%	0%	9%	0%	0%	0%	2%
Secondary School	0%	0%	5%	0%	0%	0%	1%
Supermarket	0%	0%	0%	0%	2%	0%	1%
Quick Service Restaurant	11%	0%	0%	0%	4%	0%	3%
Full Service Restaurant	17%	0%	0%	0%	2%	2%	3%
Hospital	0%	0%	0%	0%	0%	0%	0%
Outpatient Health Care	6%	0%	0%	0%	4%	0%	2%
Small Hotel	0%	0%	0%	0%	0%	0%	0%
Large Hotel	0%	0%	0%	0%	0%	0%	0%
Other – Manufacturing	0%	20%	18%	31%	0%	19%	11%
Other – Repair Garage	6%	12%	14%	8%	1%	2%	6%

As previously noted, each study sub-area represents the buildings served by a specific distribution feeder emerging from the NOVEC electrical sub-station for which we had obtained hourly load data. As NOVEC could not provide the actual locations of the distribution feeders, these feeder alignments were hypothesized by the engineering team. Once the planning team had identified the number of buildings by building type within each sub-area, the engineering team could begin building their computer simulation model of the electrical distribution network serving the entire study area.

We began by aggregating the buildings in each sub-area by customer class, and then re-allocating them to individual distribution buses along the six distribution feeders in the model. For example, sub-area E included 45 residential buildings, 145 small commercial buildings, and 59 large commercial / industrial buildings, which the model combined into 3 residential buses, 16 small commercial buses, and 13 large commercial / industrial buses. The larger number of buildings per bus in the residential sector reflects the fact that those buildings tend to have smaller loads than commercial or industrial buildings.

The final model, shown in Figure 17, included a total of 119 buses: 58 residential, 34 small commercial, and 24 large commercial / industrial, plus three distribution nodes that do not directly serve customers. Each bus is identified by number (i.e., buses 80 through 119 are on distribution feder F, at the top of the diagram), and is color-coded to identify which types of buildings it serves.

Figure 17. Schematic Diagram of Modeled Distribution Network



Each distribution bus that serves buildings with solar DPV potential (per the GIS analysis described in Section 3) was identified as “solar ready,” and is marked with an asterisk in Figure 17. In total, 20 residential, 15 small commercial, and 15 large commercial / industrial buses were identified as “solar ready.”

4.2. Estimating Power Demand in the Distribution Grid Model

Figure 17 also identifies the total peak load (i.e., peak power demand) for each bus. These values are indicated with an arrow pointing from the bus number to the corresponding load number, in kW (i.e., bus 79 at the end of line E has a peak load profile of 140 kW). The engineering team calculated these loads by aggregating the hourly load profiles of the individual buildings connected to that bus, per the OpenEI dataset (OpenEI.org, 2017).

The OpenEI dataset includes average annual hourly load profiles for residential buildings and 16 different types of commercial buildings. We took the load profiles for each building type in the

study area and performed statistical analysis to find their respective empirical Probability Density Function (PDF) and approximated fit distribution on the day of the sub-station's peak annual load. Figures 18 and 19 demonstrate the results for the two most common types of commercial buildings in the study area, small office buildings and strip malls.

Figure 18. Probability Density Function of Peak Load and Approximated Fit: Small Office

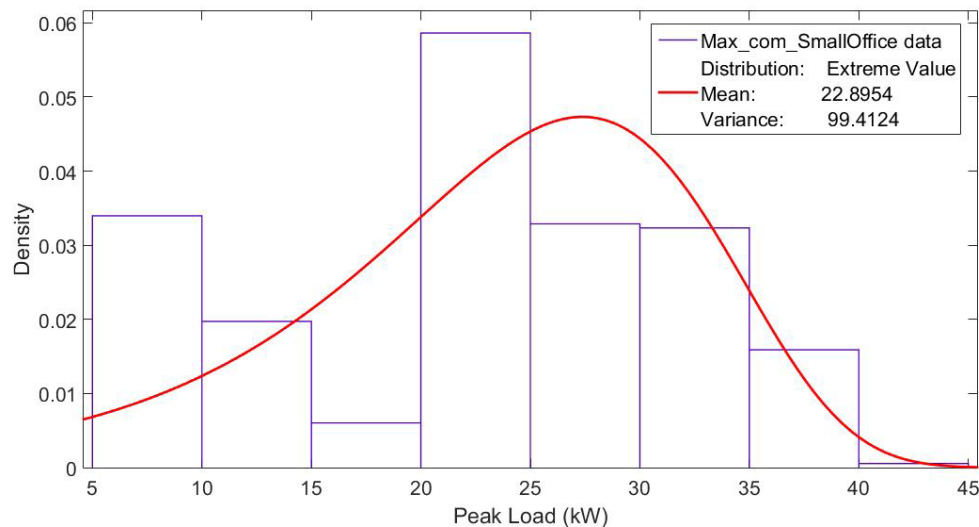
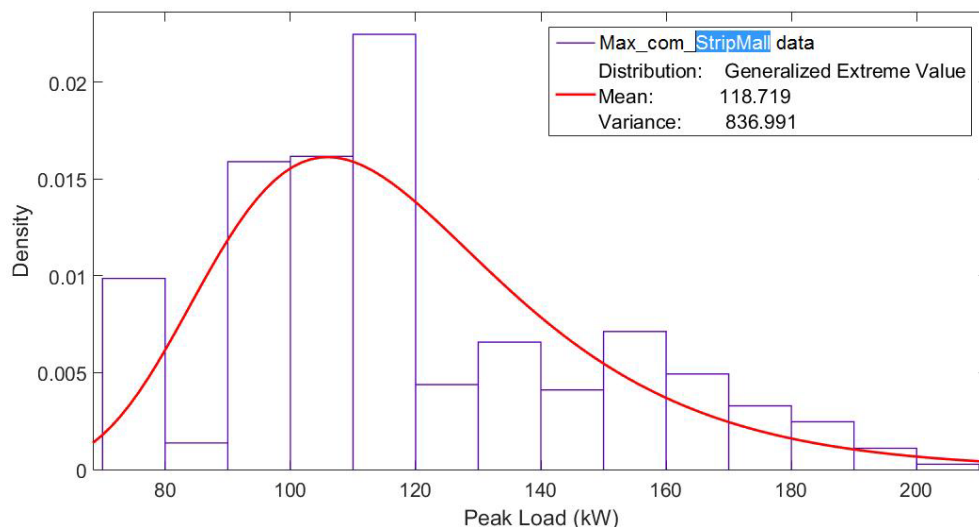


Figure 19. Probability Density Function of Peak Load and Approximated Fit: Strip Mall

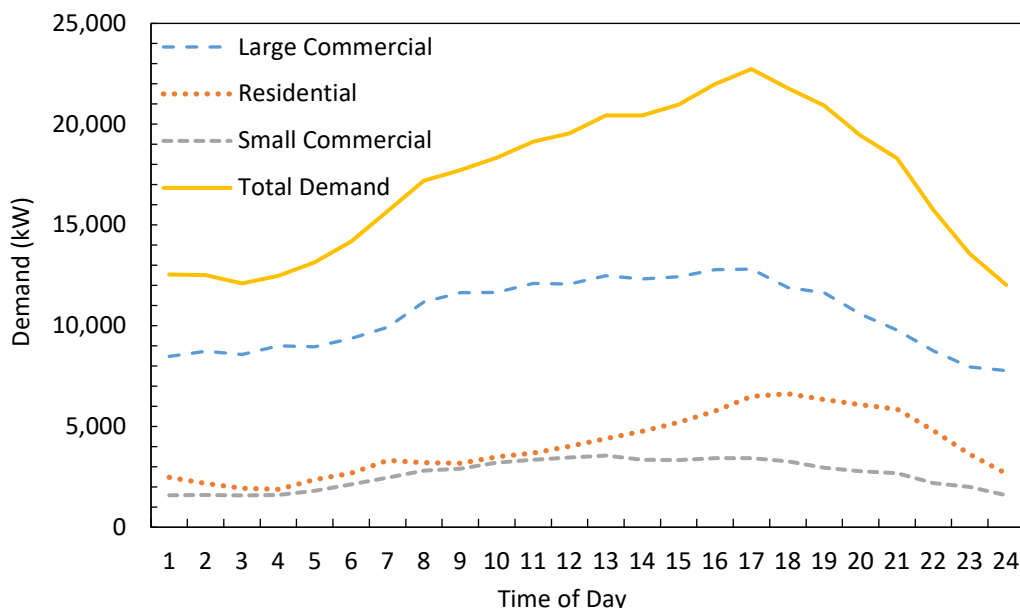


The collective load profile of all buses in the model was set to match the hourly load profile for the study area sub-station as provided by NOVEC. The aggregated load profiles for the total distribution system model, and the three customer class categories, are shown in Figure 20.

The final steps in building the base hypothetical electric distribution model were to determine the line parameters and the reactive power profile for each bus. Electrical network line parameters were assumed, based on the estimated distance between buses and conductor electrical

characteristics, with the network voltage level set at 12.5 kV. Reactive power profiles for the distribution buses were based on a statistical evaluation of power factors from the actual hourly sub-station load data provided by NOVEC. The power factor for aggregated loads was assumed to follow a normal distribution with $\mu=0.8233$ and $\sigma=0.0193$. Next, given the active demanded power for each load, the reactive power profile was calculated according to random power factors generated from a normal distribution.

Figure 20. Aggregated Load Profiles for Distribution System by Customer Class



4.3. Simulation Analysis Findings

For the final step in our analysis, the engineering team used this hypothetical electric distribution model to determine an optimal placement and sizing of DPV systems across the solar-ready buildings in the study area. This optimal allocation would be one that minimizes power loss and voltage deviation across the modeled distribution network while avoiding reverse power flows.

We performed this analysis for four different levels of DPV market penetration – 5%, 10%, 20%, and 50% – with penetration defined as total DPV capacity divided by the actual year 2015 peak demand for the study area sub-station (23,260 kW). In these scenarios, DPV capacity is not distributed randomly across the system. Rather, the model allocates DPV capacity across the distribution system buses in a way that will produce optimal system performance.

Table 9 shows the distribution system performance results for these simulations. Energy losses and voltage deviation are reduced under each scenario, compared to the base case, indicating that optimized DPV penetration improves distribution system performance. Energy losses are reduced with each increasing level of DPV penetration, whereas voltage deviation is lowest in the 20% scenario.

Table 9. Distribution System Performance under Optimized DPV Penetration Scenarios

Scenario	Total DPV (MW)	Energy Loss (kWh)	Voltage Deviation	Energy Loss Improvement	Voltage Deviation Improvement
Base Case	NA	26,995	1.8315	NA	NA
5% Penetration	1.16	26,081	1.7372	3.39%	5.15%
10% Penetration	2.15	25,837	1.6759	4.29%	8.50%
20% Penetration	4.65	24,092	1.6102	10.75%	12.08%
50% Penetration	11.63	22,998	1.6295	14.81%	11.03%

On average, across the four scenarios, the optimal allocation of DPV capacity by customer class was 34% on residential buildings, 12% on small commercial buildings, and 55% on large commercial and industrial buildings, as shown in Table 10.

Table 10. Optimal Allocation of DPV Capacity by Customer Class

Scenario	Residential	Small Commercial	Large Comm. / Industrial
5% Penetration	30%	14%	56%
10% Penetration	35%	9%	56%
20% Penetration	41%	9%	50%
50% Penetration	29%	15%	56%
Average	34%	12%	55%

Table 11 summarizes the overall project findings with respect to the residential, small commercial, and large commercial / industrial customer classes. While the residential sector accounts for 75% of all buildings, it only accounts for 24% of total electricity demand and 29% of peak load. On the other hand, large commercial and industrial buildings represent only 4% of all buildings, but 56% of electricity demand and 61% of peak load. Potential DPV capacity is fairly evenly distributed across the customer classes, reflecting the differences in average size among those building types (i.e. residential buildings are smaller on average than commercial and industrial buildings, and thus account for only 36% of potential DPV capacity, even though they represent 75% of total buildings in the study area).

Table 11. Comparison of Peak Load and Optimal DPV Capacity by Customer Class

	Residential	Small Commercial	Large Commercial and Industrial
Percent of total buildings	75%	21%	4%
Percent of potential DPV capacity	36%	28%	36%
Percent of total daily demand (kWh)	24%	15%	61%
Percent of peak load (kW)	29%	15%	56%
Share of DPV capacity (20% scenario)	41%	9%	50%
Share of DPV capacity (50% scenario)	29%	15%	56%
Share of DPV capacity (avg. of all scenarios)	34%	12%	55%

The distribution of DPV capacity by customer class in these optimal scenarios is heavily weighted towards commercial and industrial buildings. While these customer classes represent only 25% of total buildings in the study area, they account for 60-70% of optimized DPV capacity in the high penetration scenarios. The distribution of DPV capacity in these scenarios is similar to the overall distribution of peak load and daily electricity demand by customer class. In fact, the optimal distribution of DPV in the 50% market penetration scenario is exactly the same as the distribution of peak load by customer class: 29% residential, 15% small commercial, and 56% large commercial / industrial.

5. Summary and Conclusions

This report has addressed DPV grid integration issues from a number of perspectives, including both original and secondary research. Our findings illustrate the tremendous potential for continued DPV capacity growth, both in Virginia and across the U.S., with positive net economic benefits.

Our review of current research on the “value of solar” debate (VOS) shows that studies conducted on behalf of electric utilities tend to find that the costs of distributed solar outweigh its benefits, while those conducted for solar energy supporters tend to view it more favorably. Thus, the most meaningful VOS studies would seem to be those independent analyses conducted on behalf of state public utility commissions. Those PUC studies tend to find the VOS to be near or above the applicable retail rate, even without factoring in broader environmental or social benefits.

We also evaluated the previous VOS research in terms of the impacts of DPV on retail electric rates. A model developed by the Lawrence Berkeley National Laboratory (LBNL) demonstrates that increasing levels of DPV are unlikely to have a meaningful impact on retail rates unless solar energy market penetration exceeds 5%. Even then, significant price increases would only be expected if the value of solar is well below retail rates, which as noted above is not the case in most independent VOS studies.

No comprehensive VOS analysis has been completed in Virginia, leaving a 2011 study by the Virginia State Corporation Commission (SCC) as the most detailed assessment of DPV costs and benefits in the Commonwealth thus far. That study took a rather conservative approach to measuring solar energy’s value, leaving out not only broader environmental and economic benefits but also standard VOS metrics such as grid support services, financial risk, and reliability risk. The SCC also assumed substantial interconnection, customer service, and billing-related costs that are not typically included in VOS studies. Despite those unfavorable assumptions, it still found the level of DPV penetration at that time to have an “immaterial” impact on residential rates. In addition, the SCC found that increasing DPV penetration to the 1% aggregate net-metering cap would still only raise costs by an amount equal to \$6.73 per average residential customer per year.

By applying the numbers from the SCC study to the LBNL formula mentioned above, we estimate that a 2% DPV market penetration in Virginia would increase retail rates by well under 1%, while a 5% penetration would result in an increase of about 1.67%, raising the average residential electricity bill by less than \$3 per month. Furthermore, most independent, comprehensive VOS studies in recent years have calculated higher net benefits for DPV than those that the SCC calculated in 2011. Therefore, if such a true VOS study were to be conducted for Virginia, then it would quite possibly produce even lower estimated rate impacts than those extrapolated here from the SCC report.

Recent DPV “hosting capacity” studies by the U.S. Department of Energy (DOE) and the National Renewable Energy Laboratory (NREL) find that the electricity market and distribution grids could support well over 100 GW of DPV by the year 2030 and as much as 350 GW by 2050, far above the current 16 GW total. Rooftop DPV potential is even greater, with the current U.S. building stock capable of supporting nearly 1,200 GW according to NREL. For Virginia, research by NREL estimates grid capacity to be 19 GW and rooftop potential to be 28.5 GW.

Research that is more specific to Virginia and its surrounding region also points to much higher DPV potential. A study by GE Energy found that the PJM region could get up to 30% of its electricity from wind and solar, including up to 9% from DPV, without any significant operating issues, resulting in reduced fuel costs, operations and maintenance costs, and Locational Marginal Prices. A study by Navigant Consulting, for Dominion Energy, found that most of the utility's 1800 distribution feeders could support DPV penetration at up to 50% of their feeder thermal rating, without upgrades. Over 200 MW of DPV, more than four times Virginia's current state-wide capacity, could be hosted on just the 11 representative feeders evaluated in the Navigant study.

All of these prior studies indicate the potential to substantially increase DPV capacity, and they refute the notions that this would result in significant retail price increases or inevitably create major technical problems for the electrical grid. However, steps do still need to be taken to minimize short-term grid impacts from DPV growth and upgrade the grid as necessary to accommodate long-term growth. For instance, some of the hosting capacity studies mentioned above (discussed further in Section 2.2.1) assumed future grid infrastructure upgrades in their long-range estimates.

In addition, while the Navigant study found that most of the distribution feeders in the Dominion service territory could host far more DPV than is currently in place, it also found that in certain cases DPV could cause immediate problems. For example, two of the 11 representative feeders in Navigant's analysis were found to have a hosting capacity of 0 MW. Navigant concluded that concentrating DPV in a few locations on a given feeder can increase distribution system impacts and integration costs, and that lower-voltage feeders can accommodate less DPV than those that operate at higher voltages. Other studies have also found that the hosting capacity of individual distribution feeders can vary greatly.

These prior findings demonstrate the need for more research on how to increase DPV capacity without negatively impacting grid performance. While much of this work will naturally focus on medium to long-term improvements around energy storage, grid upgrades, etc., there is also a need for research on how best to avoid negative grid impacts while increasing DPV capacity in the short term. This includes applied, location-specific research that takes into account actual DPV potential and grid conditions within a given region or distribution service area.

In that light, the goal of this project was to demonstrate a method for estimating DPV capacity within a city or neighborhood-scale study area, and then modeling the optimal allocation of DPV within that study area to improve grid performance. Our inter-disciplinary approach illustrates the potential for grid operators to work with city planners in order to understand where DPV systems could be installed within a given distribution network and anticipate grid challenges that could arise. Grid operators could then use this information to make targeted investments in grid upgrades. Furthermore, this information could lay the groundwork for policies that incentivize DPV investments in locations where it would be most beneficial to grid operations.

Our research utilized real data for a specific distribution sub-station near Manassas, Virginia, including the total hourly load demand for the year 2015 and the total number of residential, small commercial, and large commercial / industrial customers that it serves. We then used real data on the surrounding building stock to identify an approximate distribution service area for the sub-

station. Our modeled study area included the same number of buildings for each of those customer classes, along with a hypothetical lay-out of distribution feeders that would connect those customers.

We then used LiDAR data to determine the average annual solar insolation received on each building's rooftop, taking into account building orientation, shading, and other obstructions. With this data we deemed roughly 1/3 of the buildings to be "solar-ready," then calculated conservative estimates of each solar-ready building's potential installed DPV capacity and resulting electricity generation.

Our analysis found the study area's total rooftop DPV capacity to be just under 25 MW, which is more than half the total statewide DPV capacity as of the end of 2017. The estimated electricity production potential from those solar-ready buildings is equal to 28% of the actual annual electricity demand in the sub-station's service area. Our relatively conservative methodology places PV on only 10% of residential rooftop space and around 15% of commercial and industrial rooftop space, compared to around 25% of residential and 60-65% of commercial rooftop space in a similar NREL study from 2008.

After completing this building-by-building assessment of rooftop PV capacity, we then proceeded to build a hypothetical distribution grid network model for the study area. This involved identifying size and specific residential or commercial/industrial use for each building (e.g., single-family detached house, small office, etc.), and cross-referencing that information with available open-source data on average hourly load profiles for those building types. We then assigned groups of similar buildings to unique distribution "bus" nodes on the hypothetical distribution grid, identifying the ones that included solar-ready buildings, and calculated the annual peak load for each bus.

We then modeled a series of scenarios to analyze the impacts on this hypothetical electrical distribution grid from four different levels of DPV market penetration – 5%, 10%, 20%, and 50%. Critically, the scenarios did not assume a random distribution of DPV systems across the solar-ready buildings in the study area. Rather, they sought to identify the optimal placement of DPV systems that would minimize power loss and voltage deviation while avoiding reverse power flows.

Each scenario led to reduced energy losses and voltage deviation, compared to the base case, indicating that optimized DPV penetration improves distribution system performance. The distribution of DPV capacity by customer class in these optimal scenarios was heavily weighted towards commercial and industrial buildings. While these customer classes represented only 25% of buildings in the study area, they accounted for 60-70% of DPV capacity in the higher-penetration scenarios. The optimal distribution of DPV was similar to the overall distribution of peak load and electricity demand by customer class.

Taken as a whole, these findings lead to the following key conclusions:

Virginia has the potential to greatly increase its distributed PV capacity, with little to no impact on retail electricity rates or electric grid operations. As discussed in Section 1.3.1, Virginia ranks 31st among all states in total DPV capacity, 38th in DPV per capita, and 45th in DPV as a percentage of total PV capacity. The state's two largest investor-owned utilities, and many of its electric co-operatives, remain far below the 1% aggregate cap on total net-metered distributed energy

capacity relative to peak demand. The various hosting capacity studies cited in this report suggest that Virginia could support far higher levels of DPV penetration, and our research corroborates those findings at the local scale. Potential methods for increasing DPV penetration include the following: adopting tax credits, rebates or other financial incentives for customer-owned DPV systems; establishing an SREC credit market, via a mandatory renewable portfolio standard or state-wide carbon trading scheme; enabling localities to establish Property-Assessed Clean Energy (PACE) loan programs for the residential sector; and encouraging localities to both implement those PACE loan programs and develop consistent, streamlined permitting procedures for DPV systems.

There is no evidence to suggest that increasing Virginia's DPV market penetration to at least 5% would cause notable retail price increases. Most recent independent VOS studies (i.e., those conducted on behalf of a public utility commission rather than an electric utility or solar energy organization) have found the net benefits of electricity from DPV systems to be equal to or above the applicable retail rate, even without factoring in broader environmental or economic benefits.

To provide clarity on Virginia's DPV policy debate moving forward, the state should commission an independent VOS study of its own. Such a study should not only quantify the net-benefits of DPV, but also include an analysis of potential electric rate impacts (if any) from different levels DPV market penetration rates, compared to business-as-usual rate increases or other future electricity market scenarios.

It should also be noted that many of the concerns about DPV integration can be mitigated through the use of advanced metering infrastructure, micro-grids, and energy storage systems. The Virginia General Assembly's passage of the Grid Transformation and Security Act of 2018 created a mechanism to fund such projects, which should ameliorate some of the concerns about potential costs associated with increasing DPV market penetration.

While these conditions indicate a strong potential for future DPV growth, with limited if any negative price impacts, this does not necessarily suggest that net-metering is the best mechanism for compensating DPV owners for their electricity generation moving forward. Some of the authors of this study recently completed another report that investigated the pro's and con's of net-metering and other mechanisms for compensating DPV "customer-generators." We argued that net metering remains the appropriate mechanism in the short term, up to perhaps a 5% DPV market penetration, given the prevailing research findings on the lack of negative DPV impacts at that level. However, many solar energy supporters envision a future with even higher levels of DPV usage, at which point some of the aforementioned concerns could become valid if not properly mitigated. Furthermore, net-metering has clear limitations as a long-term solution for a changing electricity landscape. First, it is rooted in a fundamentally flawed flat-volumetric retail pricing scheme, and therefore does not account for the fact that electricity is more valuable at different times and at different locations on the grid. Second, it creates a disincentive for DPV owners to invest in on-site energy storage and other load-shifting behaviors that are needed to facilitate a future distributed electricity network (Pitt, 2017).

In response to these challenges, some states are beginning to explore "post-net-metering" models that would compensate customer-generators based on the component values provided by DPV systems, including for example a temporal value that would be higher for electricity delivered at

times of peak demand. The model developed in New York, as part of that state's broader Reforming the Energy Vision (REV) process, also includes a "locational system relief" value that would provide higher compensation to DPV systems located in parts of the distribution grid where solar energy production would be most beneficial (New York Department of Public Service, 2017).

Our research presents a method by which such location-specific values could be incorporated into a new post-net-metering compensation model. Following the steps we have demonstrated here, electric utilities can work with urban planners to estimate building-specific energy demand curves and DPV production potential within a given distribution service area, model the potential of the feeders in that area to absorb additional DPV capacity, and identify specific locations where DPV capacity would provide the most locational value to the grid.

Finally, our analysis shows that the optimal distribution of DPV within an urban / suburban context would include a high proportion of systems on commercial buildings. This result makes intuitive sense, as 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. Our findings suggest that state and local policymakers should develop policies that support the growth of DPV in commercial districts. Such approaches could include streamlining local permitting processes and removing unnecessary zoning and building permit obstacles, allowing third-party ownership models such as Power Purchase Agreements and "shared" or "community" solar arrangements for DPV arrays on commercial buildings, facilitating the growth of PACE loan programs in the commercial sector, and creating state and/or local financial incentives for commercial-sector DPV systems.

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