UVA | FRANK BATTEN SCHOOL of LEADERSHIP and PUBLIC POLICY

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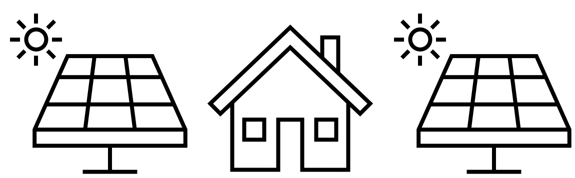
Fostering Efficient Markets and Reducing Costs for Small-Scale Solar

Policy Interventions in Virginia



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Disclaimer

The author conducted this study as part of the program of professional education at the Frank Batten School of Leadership and Public Policy, University of Virginia. This paper is submitted in partial fulfillment of the course requirements for the Master of Public Policy degree. The judgements and conclusions are solely those of the author, and are not necessarily endorsed by the Batten School, by the University of Virginia, or by any other agency.

"On my honor as a study of the University of Virginia, I have neither given nor received unauthorized aid on this Applied Policy Project."

May 1, 2022

Executive Summary

In 2020, Virginia demonstrated initative in decarbonizing its electricity sector through the historic passage of the Virginia Clean Economy Act (VCEA). Among its many provisions, this legislation purports solar energy, at both large and small scales, as an integral solution for reducing greenhouse gas emissions. Notably, several provisions support the expansion of distributed generation (DG). However, despite these legislative efforts, solar DG remains at less than 0.5% of total electricity generation (*EIA*, 2021).

Distributed generation refers to a small-scale system that produces energy at or near the source of where the energy is consumed. This differs from the utility-scale model, in which energy is produced at a large central production facility and then distributed over transmission lines to consumers. DG can be produced at residences, commercial buildings, or other micro-grid locations (US EPA, 2015). This method of energy production supports the delivery of clean energy through diversification of the grid and enhanced reliability, reduction of transmission line losses, utilization of already-developed space, and promotion of energy autonomy and utility bill savings for residents.

One main barrier to adoption of distributed solar is the high up-front cost of financing a system. An estimated 63% of the costs of DG are derivate of "soft costs", or non-hardware expenses (Fu, et al., 2018). This includes aspects such as labor, customer acquisition, and permitting. Within these processes, inefficiencies add unnecessary time and financial burdens to local governments and Virginians seeking to access DG, resulting in societal deadweight loss.

The first half of this report provides an in-depth analysis of distributed generation in Virginia, describes current policies and the literature on their efficacy, and identifies remaining barriers and areas for governmental intervention.

The second half of this report identifies three potential courses of action:

1. No intervention and maintenance of the status quo
2. Adopt a statewide mandate requiring permitting standardization through SolarAPP
3. Adopt a state-level incentivization program for locality participation in SolSmart

The outcomes of the three alternatives are projected and assessed in relation to the criteria of effectiveness, net cost, political feasibility, equity, and transparency. Based on this analysis, **it is recommended that the Piedmont Environmental Council adopts the third alternative: creation of a state-level incentivization program for locality participation in SolSmart.** This action will best facilitate market efficiency and create an effective enabling environment for distributed solar. As a non-profit entity, the Piedmont Environmental Council can build support and coalitions around this issue, partner with key stakeholders, and lobby in support of this intervention. A thorough adoption strategy is detailed at the end of this report to enable successful passage of this policy in the upcoming legislative session.

Problem Statement

As the U.S. decarbonizes its electricity generation sector, the solar energy industry is growing rapidly. Total electricity produced from solar photovoltaic (PV) sources in the US increased 30% between 2020 and 2021— large utility scale solar grew 28.5% and small scale generation facilities (distributed generation) grew nearly 18% in that same period (*U.S. Energy Information Administration*, 2022). Despite this nationwide growth, renewable sources accounted for less than 7% of total electricity generation in Virginia in 2020 (*EIA*, 2021). To remedy Virginia's lagged decarbonization efforts, the Virginia Clean Economy Act was enacted in 2020, transforming the state's viability for solar energy at all scales (Virginia Clean Economy Act, 2020).

Distributed generation can help support the delivery of clean energy through diversification of the grid and enhanced reliability, reduction of transmission line losses, utilization of already-developed space, and promotion of energy autonomy and utility bill savings among residents. Despite the legislative efforts of the VCEA and recent increased solar investment, solar distributed generation (DG) remains at less than 0.5% of total electricity generation (*EIA*, 2021).

One main barrier to adoption of distributed generation solar is the high up-front cost of financing a system. An estimated 63% of the costs of DG are due to "soft costs", or non-hardware costs (Fu, et al., 2018). This includes aspects such as labor, customer acquisition, and permitting. Within these processes, inefficiencies can add unnecessary time and financial burdens to local governments and Virginians seeking to access DG, creating societal deadweight loss. For instance, administrative barriers and fees complicate processes, add delays, and increase cost recovery uncertainty. This translates to higher soft costs and negative customer experiences, further inhibiting adoption of DG.

Virginia can facilitate efficient market preparation and create an effective enabling environment for distributed solar. **Reducing costs and program inefficiencies of distributed generation is necessary for encouraging efficient and equitable growth in Virginia's solar energy capacity**.

Client Overview

This Applied Policy Project is prepared for the Piedmont Environmental Council's (PEC). PEC is a 501(c)3 non-profit organization founded in 1972, headquartered in Warrenton, VA. The mission of this organization is "promoting and protecting the natural resources, rural economy, history and beauty of the Virginia Piedmont" (Piedmont Environmental Council, n.d.). This community-based environmental group in the nine-county Piedmont region of Virginia works to preserve natural resources, strengthen rural economies, build smart transportation networks, and promote sustainable energy choices (Piedmont Environmental Council, n.d.). Within this mission scope, land conservation and renewable energy are key priorities for the organization. Currently, PEC provides education and technical assistance for homeowners and small businesses to install solar panels. PEC is interested in Virginia state-level policies to help promote the take-up of solar panels on homes, offices, and other buildings, as this intersects several organizational missions. This report aims to help diagnose inefficiencies and barriers in the distributed solar market in Virginia, then propose policy interventions to address these issues.

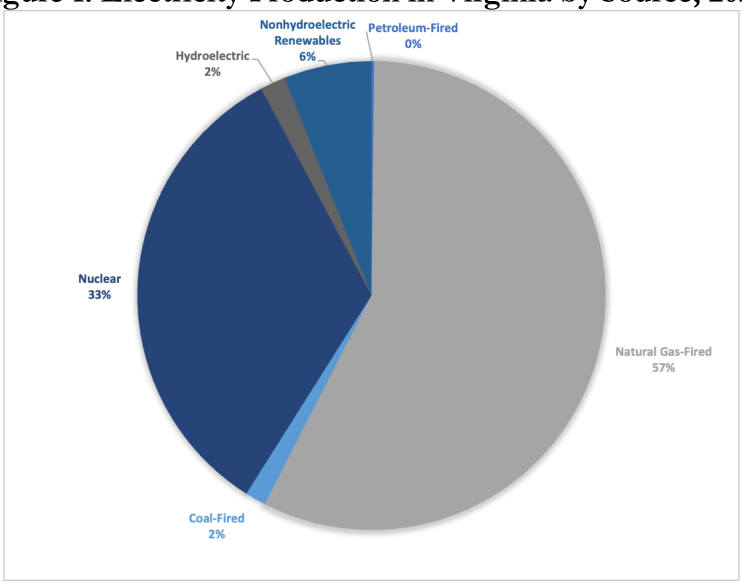
Piedmont Environmental Council

Background

Profile of Virginia's Electricity Generation

Although the share of Virginia's electricity generated from renewable sources has been increasing in recent years, renewable energy accounted for less than 8% of total electricity generation in Virginia in 2020[1] (U.S. Energy Information Administration, 2021). Figure 1 shows the breakdown of Virginia's electricity generation by source. Ninety percent of Virginia's electricity was produced from natural gas and nuclear sources. Historically, the share of electricity produced from coal sources in the state has been declining. Coal accounted for most of the electricity produced in state until 2009, and in 2019 renewable generation exceeded the amount of electricity produced from coal for the first time in the state's history (U.S. Energy Information Administration, 2021). As coal sources decreased, reliance on natural gas increased. Additionally, as the composition of electricity generation shifted over time, Virginia's electricity production increased 40% between 2010 and 2020, indicating increase supply to meet the growing energy demand. However, despite the sector expansion, Virginia's consumption exceeds production electricity from two regional grids is imported.

Figure 1: Electricity Production in Virginia by Source, 2020



Source: Author's calculations. Data Source: (U.S. Energy Information Administration, 2021)

Among the nonhydroelectric electricity produced, solar photovoltaic (PV) mad up 1.7% of total generation in 2020. The first utility-scale solar (USS) facility began operating in the state in 2016, and recent investment caused the amount of solar energy to double between 2018 and 2020. While most of the solar energy produced in Virginia is USS, small scale facilities accounted for nearly 12% of total solar generation in Virginia as of 2020, and both small and large scale facilities are projected to increase in coming years (U.S. Energy Information Administration, 2021).

[1] This report focuses on electricity (rather than total energy) and on generation (rather than consumption). This follows recent decarbonization efforts per the Virginia Clean Economy Act.

In Virginia, most electricity is supplied by three large investor-owned utility companies, Dominion Energy, Appalachian Power, and Kentucky Utilities (formerly Old Dominion Power). There are also thirteen member-owned electric co-operatives and eleven municipally or publicly owned operators, serving about one-third of total ratepayers altogether (Virginia State Corporation Commission, 2020). Dominion Energy is the largest electricity supplier in the state and services 2.6 million residential customers (Associated Press, 2021). For a map of the service area territories, see Appendix A.

Impacts of Climate Change in Virginia

Investing in renewable energy is a key mechanism to reduce greenhouse gas emissions. Increased carbon dioxide in the atmosphere causes rising temperatures, increased precipitation variance, and higher frequency of extreme weather events. Uncertainty and fluctuation in water supplies and extreme weather events harm agricultural yields and stress livestock production. In Virginia, agriculture provides about 122,000 jobs and $27 billion in economic activity (Steinfeldt, Coil, and Plag, n.d.). Half of Virginia's counties face potential water supply issues in the coming decades given hotter, drier climates— nearly $500 million of crop production is produced in these water-risk regions (Steinfeldt, Coil, and Plag, n.d.). Consequently, climate change poses a serious threat to food supplies and rural livelihoods (Walthall, et al., 2013).

In coastal regions, rising sea levels derivative of anthropogenic warming threaten to erode beaches, increase flooding, and submerge lowlands. The Environmental Protection Agency (EPA) notes that water is rising faster in Virginia than elsewhere in the nation, and sea levels in coastal regions are expected to rise between 16 inches and 4 feet (Sweet et al., 2022; Steinfeldt, Coil, and Plag, n.d.). In the southeastern area of Virginia, temperatures are predicted to rise to 95°F between 20-40 days of the year, compared to 10 days per year at present. There are public health concerns that arise from higher temperatures. Rare diseases such as Lyme Disease now present increased risk across the state. Extreme heat events increase the occurrence of heat-related stroke and dehydration (Steinfeldt, Coil, and Plag, n.d.). Finally, the impacts of climate change affect a variety of natural ecological processes.

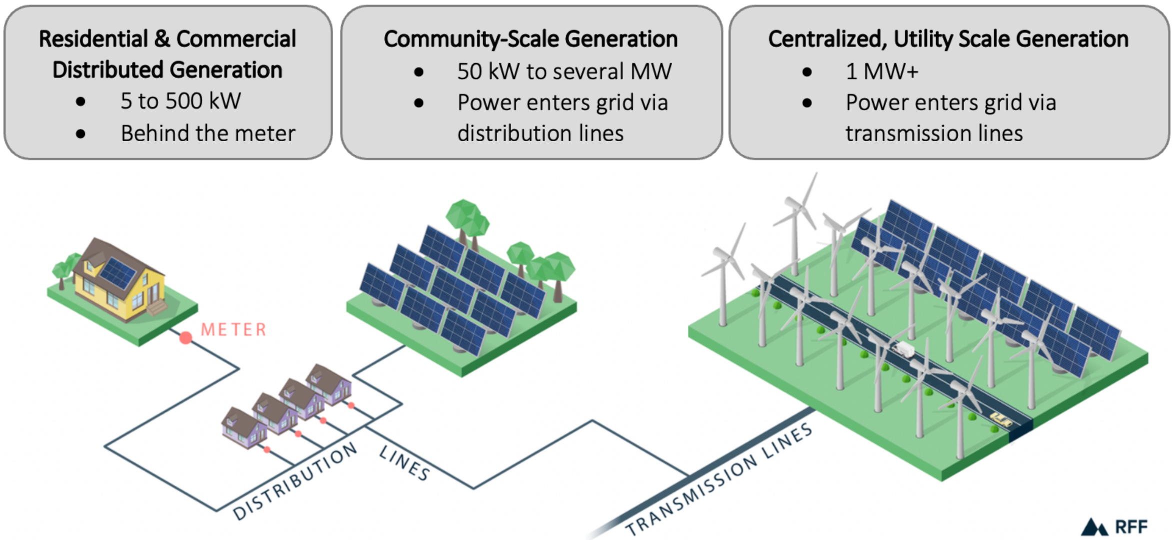
What is Distributed Generation?

Solar energy generation occurs at both large (utility) and small scales. Small scale generation is often referred to as distributed generation. Distributed generation (DG) refers to a system that produces energy, typically from renewable sources, near the source of where the energy will be consumed, called "behind the meter" generation (US EPA, 2015). This differs from the utility-scale model, in which energy is produced at a large central production system and then distributed over transmission lines to consumers. Distributed generation can be produced at residences, commercial buildings, or other small micro-grid locations (US EPA, 2015). While wind and other renewables (and sometimes non-renewables) can qualify as DG, in the context of this report DG will refer to solar distributed energy. Most often, this is in reference to rooftop solar panels. Solar systems are referred to by their installed capacity sizes. Typically, residential DG systems are 10kW or smaller. Commercial DG systems generally are larger than residential systems, up to 500 kW.[2] Typically, USS systems are 1 MW or larger, though much larger systems exist. Figure 2 below summarizes the

[2] The "commercial" share of DG encompasses DG solar systems installed for commercial, industrial, agricultural, school, government, or non-profits entities and buildings.

differences between USS and DG in terms of size and grid connectivity. Note that there is no formal delineation of what constitutes community or utility-scale solar based on size. Essentially, community solar (referred to as "shared solar" in Virginia) can be vied as a form of "smaller" USS, since it is not produced behind-the-meter, like DG.

Figure 2: Renewable Energy Generation and Integration into the Grid



Source: Authors' Modifications, from Cleary and Palmer (2020)

While DG sources produce the energy they consume, in the US context these systems are almost always connected to the larger electricity grid. The process of connecting a DG system to the grid is called interconnection. An interconnected system also allows the user to consume energy produced from the larger utility grid at times when their solar system does not produce enough electricity to cover their consumption needs. Plus, when DG systems produce more energy than the owner consumes, excess electricity can flow back into the grid via the interconnection (US EPA, 2015).

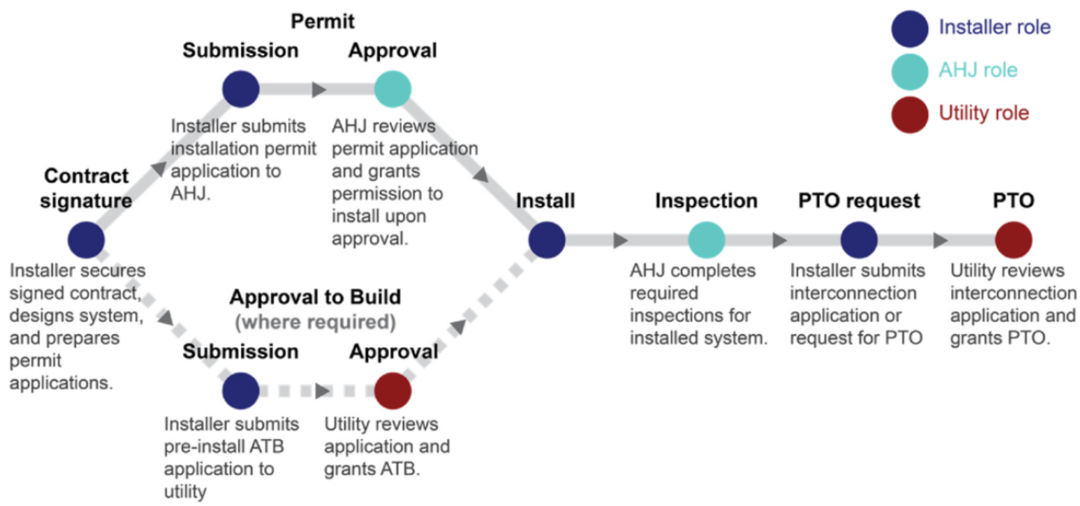
Distributed Solar Installation Process

The process to acquire, install and interconnect a DG solar system to the energy grid involves several steps and multiple stakeholders. Processes vary by developer and locality, but the general process is as follows (Schell, n.d.):

1. **Consultation**: A solar company assess the property, energy use, and other important information. Often this consultation is provided for free to consumers.
2. **Quote**: Within a few days, the developer discusses the cost, return on investment, environmental impacts, and available incentives.
3. **Contract Signing**: The consumer signs the contract with the solar company.
4. **Paperwork and Permits**: The solar developer files the necessary paperwork, permits, utility notification and other documents to begin construction.
5. **Installation**: The solar developer installs the system on the property.
6. **Inspection**: The locality inspects the installation to ensure safety and code compliance.
7. **Interconnection**: The solar developer submits a "permission to operate" (PTO) request to the utility company, asking the utility to interconnect the system to the grid.
8. **Permission to Operate**: The utility grants the PTO, and the panels begin generating power.

Figure 3 summarizes the process from the signed contract onward, highlighting what stakeholders are involved at each stage. Communication is needed throughout the process between the local authority holding district (AHJ)[3], the solar installer, and the utility company, as these stakeholders hold various responsibilities at different points in this timeline. Steps four, six, seven and eight of this process are often referred to the Permitting, Inspection, and Interconnection (PII) part of the development process and is a point in the process in which local government action can impact the timeline and costs of DG acquisition.

Figure 3: Schematic Overview of a Typical PII Timeline



Source: O'Shaughnessy et al (2022)

Impacts of Distributed Generation

Distributed generation can help support delivery of clean energy through diversification of the grid and enhanced reliability, reduction of transmission line losses, and utilization of already-developed space (US EPA, 2015). Distributed generation also directly helps consumers reduce utility bill savings and has positive job creation and economic development implications.

When energy is produced at a centralized location and transferred across transmission lines to consumers, some energy is lost. In 2020 in Virginia, total transmission and distribution losses equated to 5.3% of electricity transmitted across the grid (Energy Information Administration, 2021). Through local production of energy, DG has the potential to reduce these line losses (Rangarajan et al., 2014; Chiradeja, 2005). Advocates also argue that DG may save electric utilities money on conventional generation fuels, peak demand shaving, help avoid new generation capacity investments due to diversified supplies, and reduced strain on existing transmission and distribution infrastructure and congestion (Pitt & Michaud, 2015).

Additionally, investment in DG can also be a driver of economic development, creating construction jobs and manufacturing opportunities (Pitt & Michaud, 2015). Minnesota's largest

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[3] An authority holding district (AHJ) is the locality in which the DG system is located. In Virginia, this is the local government, either the city or county. There are 133 AHJs in Virginia.

utility company found that small-scale solar development and installation produces 30 times more jobs per dollar investment than does USS (Farrell, 2021). In Virginia specifically, research found that DG creates more construction and operations and maintenance jobs per megawatt than other energy technologies: 8.33 jobs/MW for small commercial solar and 14.50/MW for residential solar, compared to 6.88 jobs/MW for nuclear and 1.33 jobs/MW for natural gas (Meister Consultants Group, 2015).

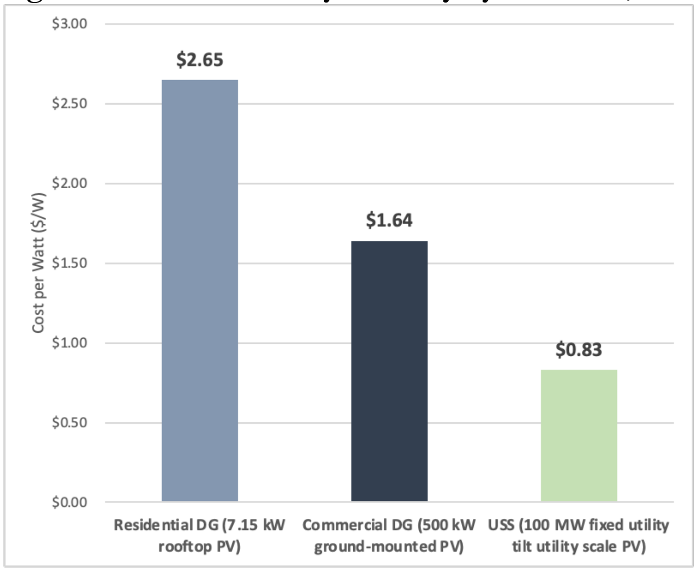
Finally, DG can be advantageous to promote conservation efforts in some spaces, as it utilizes already disturbed and developed land spaces. Virginia lost an average of 72 square miles of tree canopy per year between 2014 and 2018. This threatens habitats and the preservation of historical and cultural land, as well as exacerbates the effects of climate change due to loss of carbon sequestration (Grebe, Hunsinger, and Jurczyk, 2021). USS developments require large land areas—on average, it takes seven to ten acres of land to produce 1 MW of electricity with USS sites (Barnes and Holmes, 2021). DG does not need to contend with these land use issues since it is situated on already-developed property sites and rooftops.

Importantly, DG fundamentally changes the business model of centralized utilities. As such, DG often causes resistance from utility companies. Some individuals have voiced concern that high penetration levels of DG will erode revenue to the point at which utility companies cannot pay off existing infrastructure investments, resulting in "stranded asset" costs (Pitt & Michaud, 2015). Also, utility companies contend that increased customer-owned system interconnections may require upgrades to the grid system and create costs that must be passed on to other ratepayers. Over the years, many studies have attempted to analyze the net value of distributed solar. These studies cover a wide variety of methodologies, assumptions, and perspectives. Many of these are commissioned by utility companies, state public utility commissions, or solar industry advocates. Consequently, biases either in favor or against distributed solar are of concern, and resultingly the costs and benefits considered and monetized vary substantially (Pitt & Michaud, 2015). A more detailed discussion of this debate can be seen in the following section discussing net-metering. Overall, it is difficult to analyze the level of penetration of DG that would meaningfully warrant the concerns expressed by utility companies. Nevertheless, Virginia is in a premature stage of DG development, and so significant cost-shifting concerns is likely unwarranted at this stage (Pitt & Michaud, 2015).

Cost of Distributed Generation

While cost-effective analysis often fails to monetize several benefits mentioned above, nonetheless, it is accepted that USS is more cost-efficient. DG is more costly per megawatt than USS, since large-scale development can leverage economies of scale. That said, costs of both DG and USS have declined rapidly in recent years. Figure 4 compares the average national cost of various system sizes in 2021, from small-scale DG to large-scale utility solar. The average national cost for a residential system is $2.65/W. For an average 7-kW capacity system, amounts to a total cost of $18,550. However, there is a federal tax credit and other incentives and policies aimed at lowering the levelized cost of energy, discussed in the following section.

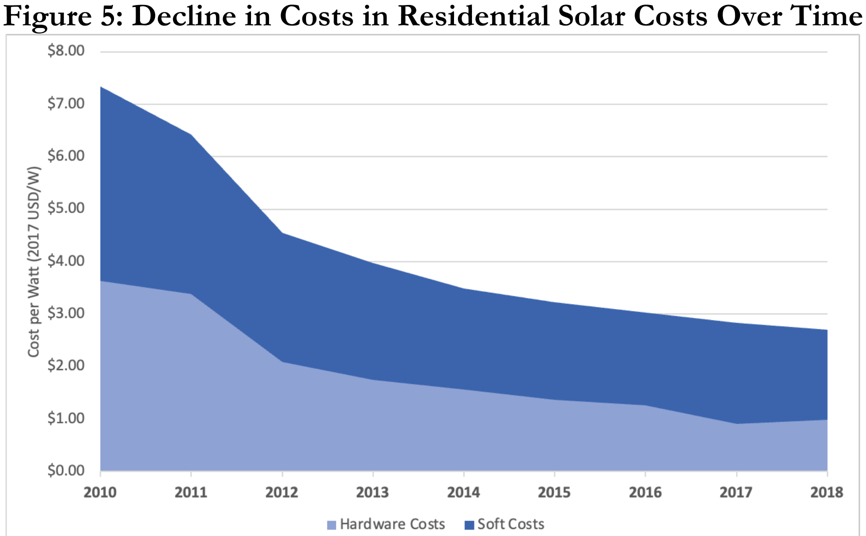
Figure 4: Cost of Solar Systems by System Size, 2021



Source: (Ramasamy et al., 2021)

The cost of solar, across all system sizes, has decreased dramatically over time. Interestingly, the cost per kW of energy produced for DG remains higher than USS in large part due to the "soft costs." Soft costs are the non-hardware costs of solar, such as permitting, and transaction costs. The National Renewable Energy Laboratory identifies seven soft cost categories: "permitting, inspection and interconnection (PII), install labor, sales tax, overhead, net profit, customer acquisition, and supply chain costs" (Fu, et al., 2018). Figure 5 shows the soft and hardware costs of residential solar over time. From 2010 to 2018 the overall system cost of residential DG decreased 116%, while hardware costs decreased 267% (Fu, et al., 2018). Hence, soft costs account for an increasing share of the total DG price, and currently make up two-thirds of system costs.

Figure 5: Decline in Costs in Residential Solar Costs Over Time



Source: Authors' Calculations. Data Source: (Fu et al., 2018)

A discussion of factors that contribute to higher soft costs and the ways in which policy has, and has failed to, reduce prices is discussed in the following two sections.

Current Policy and Programs Regarding DG

This section details Virginia's current policy regarding renewable energy and DG. A variety of federal, state, and local programs exist to foster DG development. Additionally, a landmark piece of legislation, the Virginia Clean Economy Act (VCEA), was passed in 2020 and provided the largest revision of statewide renewable and solar policy in recent years.

Federal Policies

Investment Tax Credit
One of the main financial incentives for DG is the federal Investment Tax Credit (ITC), which residents can claim to offset solar photovoltaic purchase and installation costs. DG systems must be owned (not leased) by the taxpayer, and the system must be located at the primary or secondary residence of the taxpayer (community solar projects are non-qualifying). Prior to 2023, this nonrefundable credit offset 26% of the investment cost through a reduction in tax liability; this rate is set stepped down to 22% at the end of 2022 and is set to expire by 2024 unless renewed by Congress (Solar Energy Technologies Office, n.d.). This policy is often cited as a main driver in the growth of DG in the past decade due to its sizable role in reducing costs and payback periods (Regan et al., 2021; Formica & Pecht, 2017; Comello & Reichelstein, 2016; Dong et al. 2017). Industry analysts project the proposed extension of the ITC would increase DG deployment above the base outlook by 31% in the residential sector and 14% for non-residential DG over the next decade (*Wood Mackenzie*, 2021).

USDA's Rural Energy for America Program (REAP)
This program gives grants, loan guarantees, and financial products for agricultural producers and small businesses to access to energy efficiency and renewable energy technologies (USDA Rural Development, 2015).

US Small Business Association (SBA) Green Mortgages
This federal program provides loan guarantees to small businesses and homeowners refinancing that are interested in investing in retrofitting facilities or purchasing renewable energy equipment. Specifically, the SBA loan programs 7(a) and CDC/504 are available to assist to Virginia residents (*504 Loans*, n.d.).

State and Local Policies

Virginia's Department of Environmental Quality provides details on the programs available to DG investment (VA DEQ, n.d.). Key state policies incentivizing DG include:

- Net-metering[4]: applicable to residential DG systems up to 10kW and commercial systems up to 500kW
- C-PACE: applicable to commercial, nonprofit, or multifamily buildings to finance clean energy projects through a loan secured by a lien and repaid back as part of their utility bill payments
- The Solar Energy Equipment Tax Exemption: allows residents, businesses, and industries to partially exempt solar energy equipment from local property taxes

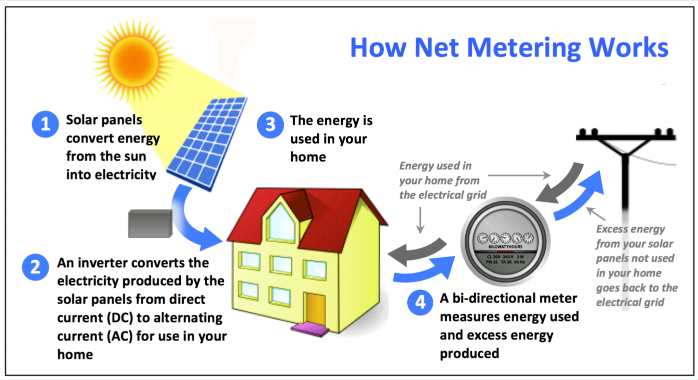
[4] See the following call-out box for details on the structure and implications of this policy.

- Business Energy Investment Tax Credit: available only to businesses and utilities, this is a tax credit equal to 30% of expenditures on various qualifying solar projects
- Virginia*SAVES* Green Community Program: provides subsidized financing to private commercial and industrial, non-profit, or government borrowers for renewable energy and other qualifying projects. This program leverages allocations from qualified bonds and works with third-party funding sources to finance projects (*VirginiaSAVES*, n.d.)

There exists heterogeneity in policies at the locality level. For instance, the Solar Energy Equipment Tax Exemption is a state law that merely gives localities the option to allow a tax exemption for solar energy equipment. Only 29 localities offer this incentive as of 2020, in either partial or full capacity (*DSIRE*, 2020). Other localities, such as Alexandria and Fairfax have more robust programs to install DG on public buildings and to conduct outreach and communication regarding solar installation to residents.

Net-Metering: A Driving Force Behind DG Growth

Net-metering policies establish a billing mechanism allowing residents with solar panels who generate more electricity than consumed to receive partial compensation for energy provided back to the grid. In Virginia, this means that residents can sell excess electricity produced from a DG system back to the utility at the retail rate. Currently, net-metering is available in investor-owned and cooperative utility service areas, but not mandated to be available in municipal utility service areas (Virginia Administrative Code Title 20, *n.d.*).



Source: (Solaflect Energy, 2020)

Net-metering shortens the financial payback period of DG investments and fosters growth in this market (Darghouth, Barbose, and Wiser, 2011; Saha and Mura, 2016; Lowder et al., 2015).

However, the impact of this policy has been debated in recent years. Researchers have noted concerns over a "cross-subsidy" effect, in which electricity rates for non-DG ratepayers increase, due to DG consumers using the distribution system but not paying for maintenance and other costs to the utility through energy bills. On the other hand, advocates argue that DG can help avoid costly transmission upgrades and decrease line losses. Solar advocates argue that value calculations should include all the benefits of DG (e.g., environmental, economic). Studies on the impact of net-metering all vary depending on the assumptions used and the costs and benefits accounted for (Pitt & Michaud, 2015).

Furthermore, biases may impact these findings. For instance, some solar industry estimates include broader societal and utility benefits, finding that the benefits of DG are $.10 to $.35 per kilowatt-hour in some states. Contrastingly, in 2011 the Virginia State Corporation Commission estimated that DG penetration levels that reach 1% of peak load cost the utility $.03/kWh, which would increase the customer bills of non-solar ratepayers by 0.5%. Utility companies contest that this cost-shifting is higher (Pitt & Michaud, 2015). Yet, some public utility commissions in California, Mississippi, Arizona, Vermont, Nevada, and Minnesota include some environmental and/or societal benefits and in fact find a positive value of DG (Pitt & Michaud, 2015; Mura & Saha, 2016).

Nevertheless, a meta-analysis on this literature analyzed value of solar estimates to date and found utilities' concerns are valid, though likely premature. Given the current level of DG penetration (in all states except, perhaps, California), evidence suggests grid integration costs are minimal, even without including societal benefits (Pitt & Michaud, 2015). Similarly, the National Renewable Energy Lab estimated that significant concerns about cost-shifting concerns are not realized until DG penetration accounts for between five to ten percent of total electricity generation, though this depends on the utility's costs and the societal value of solar (Satchwell et al., 2014; Barbose, 2018). In Virginia, current penetration is less than 0.5% and net-metering is capped at 6% of total peak generation. As such, for the scope of this report, significant concerns of cost-shifting are likely not warranted at this stage in market penetration.

The Virginia Clean Economy Act

In 2020, the Virginia Clean Economy Act (VCEA) was enacted, paving the way for the state to achieve carbon neutrality in its electricity generation sector by 2050. The VCEA transformed the viability for renewable energy development, particularly for solar energy. One of the central provisions of the VCEA was its replacement of the state's voluntary Renewable Portfolio Standard (RPS) with a mandatory one. Now, Virginia's two largest investor-owned utilities, Dominion Energy and Appalachian Power Company, are required to stop selling energy produced from fossil fuels by 2045 and 2050, respectively. Targets for the share of total electricity generation derived from renewable sources are set periodically along the transition pathway; fines will be issued for failure to meet these standards (Virginia Clean Economy Act, 2020). There are also several new regulatory amendments and requirements regarding the development of renewable generation and storage facilities.

To create a robust renewable energy market, Solar Renewable Energy Credits (SERC) were created. Within the regional energy market in which Virginia participates, any solar owner (including residents with rooftop panels) generates a SERC once their system produces 1,000 kWh of energy. These credits can then be sold in the regional market to help utilities avoid fines. This structure incentivizes small-scale solar investment and shortens owners' payback period (Solar United Neighbors, n.d.).

Additionally, this legislation amended the net metering program in two ways. First, the MW capacity of nonresidential renewable generation facilities participating in net metering was increased to 150% of consumption. Second, the systemwide cap on the amount of distributed generation allowed to be sold back into the grid increased from 1% to 6% of total forecasted load (Virginia Clean Economy Act, 2020). Of that 6% cap, 1% is carved out for low and moderate income residents. This enables more individuals with DG to sell excess produced energy back into the grid; by creating certainty in financial return, this incentivizes solar investment.

In the commercial DG space, the VCEA expanded Virginia's systemwide cap on Power Purchase Agreements (PPA) to 1,000 MW in Dominion territory and 40 MW in Appalachian Power territory, a vast increase from the previous pilot programs. PPAs allow third party developers to install, own and operate a DG system and then lease the system to the property owner. This is a critical financing tool to enable non-profits, schools, and other public entities and resource-constrained communities to realize utility bill savings from on-site solar. These entities are tax exempt and can't leverage incentives or may not have the up-front capital to invest in DG. Thus, a PPA allows the solar company to leverage tax credits and provide upfront capital, while managing repayment by the consumer on favorable terms (Virginia State Corporation Commission, n.d.).

Another provision enables the development of shared (i.e., "community") solar programs in Dominion service area. The VCEA expanded a pilot program by increasing the cap on shared solar and created another program for multi-family residential buildings. Subscribers to these programs pay a fee to obtain a certain share of a solar photovoltaics system owned and operated by a third party. Then, subscribers receive credits to offset their utility bills from the energy their subscription generates. Ultimately, this opens DG access to renters and residents in multifamily buildings in which they do not own their rooftops. It also expands access to residents who cannot afford the up-front cost of a DG system. The Shared Solar Program is capped at 150 MW and 30% of subscribers must be low-income (Dominion Energy, n.d.). Currently, rulings in the SCC have determined that the permissible minimum bill for this program is $55, which solar advocates and legislators claim unreasonably and severely prohibits take-up of the program (Misbrener, 2022). While an important aspect to equitable and increased proliferation of DG, the debate surrounding the viability of shared solar is beyond the scope of this report.

Moreover, several VCEA provisions aim to reduce energy poverty and center environmental justice. The VCEA established the Percentage of Income Payment Program (PIPP), which caps energy bills at a certain share of income for low-income residents. Other sections amend language on environmental justice in environmental impact statements and in the usage of the social cost of carbon. Another provision requires investor-owned utilities "to consult with the Clean Energy Advisory Board on how best to inform low-income customers of opportunities to lower electric bills through access to solar energy" (Virginia Clean Economy Act, 2020).

Evidently, Virginia is ramping up its USS and DG efforts to meet its RPS. In this effort, the economic implications of climate policy on residents, particularly vulnerable communities, is a central pillar of Virginia's energy targets. From allowing shared solar programs in Dominion Energy territory, to increasing the cap on net metering, Virginia is invested in facilitating access and growth in the distributed solar market. However, high costs of distributed generation, heterogeneity of market efficiency across localities, and other barriers continue to hinder the efficient deployment of DG. The following section details the key remaining challenges facing proliferation of DG.

Policy Efficacy and Remaining Barriers

Despite the recent legislative efforts of the VCEA and other programs for distributed solar, pain points in the DG acquisition process remain. Moreover, there are several important considerations regarding the effectiveness of current policy designs. This section considers those challenges, setting motivation for the policy recommendations provided in this report.

How Effective are Current Policies?

While recent studies and industry reports model the ITC as helping generate new investment in DG, the literature on efficacy of financial incentives, particularly at the state level, is mixed. Difficulties in establishing causality, disentangling policy effects at various levels of government, and data availability limit this body of research. Nonetheless, several studies attempt to circumvent these issues, and find insignificant effects of financial incentives on PV adoption (Shrimali and Kniefel, 2012; Li and Yi, 2014; Shrimali and Jenner, 2013). Adding nuance to this conversation, Sarzynski et al. (2012) found that offering cash incentives, such as rebates, is correlated with stronger deployment of PV technology; state-level tax incentives such as income, sales, or property tax incentives did not correlate with stronger solar deployment. The authors hypothesize that the simplicity and size of the incentive impact the behavioral response, and rebates may be simpler than tax exemptions, credits, and deductions. Other studies, particularly more recent modeling efforts of the ITC, find positive impacts (Kwan, 2012; Sawhney et al. 2014; Comello & Reichelstein, 2016; Dong et al. 2017; *Wood Mackenzie*, 2021). The ITC may show more positive impacts on rates of PV development than other tax credits because it is a large, well-known incentive, in line with the hypothesis of Sarzynski et al. (2012). Therefore, in Virginia, it is probable that the policies meaningfully reducing the high capital barrier to DG and causally impacting DG adoption are the ITC, net-metering, and loan and financing programs, as opposed to other tax credits and complexly designed financial incentives.

There are distributional considerations to financial incentives, as well. The ITC is a nonrefundable credit, meaning that it can only be used to offset tax liability. This disproportionately benefits wealthier households, who are much more likely to have federal tax liability. It is often difficult to estimate the impact of policies on incentivizing *new* investment, as opposed to providing a windfall to (typically higher income) consumers who would have invested in solar irrespective of monetary incentives. For instance, Coffman et al. (2016) find that wealthy homeowners often receive larger returns from Hawaii's state solar tax credit. The tax credit redistributes wealth from middle and low-income residents to upper-income taxpayers who already have sufficient means and incentive to install PV— high electricity prices and falling costs make DG profitable in Hawaii without state policy support. Consequently, current payback periods, electricity prices and redistributive impacts are important considerations when analyzing the impact of tax credits to foster DG growth.

Where is Policy Intervention Needed?

Given tax credits, exemptions, and other incentives do not achieve the greatest degree of equity or efficacy in generating small-scale solar growth, where should policy focus be directed to meaningfully reduce costs and increase access to DG in Virginia?

Fostering Market Readiness

A meta-analysis of the literature concluded that while policy incentives may have an impact on DG market penetration, they should be strategically layered on top of high quality market access policies.

Subsequent literature supports this, arguing lower cost alternatives— such as those targeted at process standardization, net metering, and market creation— are preferential to financial incentives (Doris & Chavez, 2015; Doris & Krasko, 2012; Steward et al., 2014; Cox, 2016).

Consequently, policymakers in Virginia can support DG growth by fostering market readiness— such as removing zoning barriers and ordinances preventing solar— or improving efficiency in permitting, installation, and other acquisition processes. By focusing directly on factors that contribute to high costs and inefficiencies in solar markets, governmental action can reduce societal deadweight loss and facilitate efficient and equitable deployment of DG resources.

Permitting, Inspection, and Interconnection
As mentioned, two-thirds of the total system cost of DG are soft costs. Among these soft costs are costs related to permitting, inspection, and interconnection (PII), which are within the scope of policymakers' direct and indirect influence. During the permitting and inspection stages, the AHJ directly ensures the solar system is compliant with building, fire, and electrical codes. The developer submits the permitting documents and the AHJ reviews and approves them. However, if revisions are needed, then the paperwork is sent back to the developer for resubmission, and the processes takes longer. Once approved, the developer installs the system, and subsequently the AHJ conducts an inspection to confirm compliance. While these codes and permits ensure public safety, often extremely onerous processes add time, labor, and transaction costs, without adding significant safety benefits. O'Shaughnessy et al. (2020). found that customers wait between 25 to 100 days from permit application submission until inspection; this delays realization of DG benefits— from utility bill savings to reduced carbon emissions. Hence, due to the multitude of transactions and stakeholders, the entirety of PII is must costlier than the face value permit fee AHJ's charge.

While some national averages estimate that PII costs are only about $.06/W[5], which represents 2.25% of total system costs, other evidence suggests that these costs are much higher (Benda, 2020). The Solar Energy Industry Association (SEIA) estimates the national average *direct* costs of permitting to be $.13/W, and the total direct and indirect costs to amount to $1.00/W, which is over 35% of the total system cost (*Solar Soft Costs*, 2019). Further, each AHJ can set its own permitting, building code standards, and process designs. This decentralized approach has led to immense variation in PII processes and costs across jurisdictions, with PII reforms leading to smaller soft costs (O'Shaughnessy et al., 2022). Dong and Wiser (2013) estimate city-level impacts of streamlined permitting in 3,000 PV installation across 44 California cities. Their results indicate that the most favorable permitting practices (compared to cities with the most onerous permitting processes) reduce average residential PV prices by 4-12%, holding constant other factors. Similarly, Burkhardt et al. (2015) find that local permitting procedures lead to price differences of $0.18/W between the jurisdictions with the most and least favorable permitting practices (this is 6.8% current total system costs for a typical 5-kW residential PV installation).

Another way in which inefficient processes increase system costs is through cancellation. Data from SEIA members show that a one-week delay in system installation due to PII processes increases the likelihood of client cancellation by 10% (*Solar Soft Costs*, 2019). Cancellations drives up prices for other consumers. However, other estimates indicate that while costs added due to cancellations may be significant (between $.04/W and $.40/W, with a median value of $.10/W), cancellations during the PII stage are relatively rare, consisting of approximately 2% of total cancellations (Cruce et al.,

[5] The national average total system cost in is approximately $2.65.

2022). Nevertheless, this study analyzed medium and large-sized installers, and the impact of smaller installers and those specific to Virginia is an area for further study. Irrespective of the impact of cancellations themselves, clearly soft costs are an important aspect of total system costs and an area in which policymakers can intervene to implement best practices.

Improving Transparency and Standardization

Finally, a key obstacle is the lack of transparency and available data specific to Virginia. No state-level or AHJ-level data on soft costs or installation timeline exists for the state of Virginia. For instance, only 23 of Virginia's 133 localities are listed in the National Renewable Energy Lab's SolarTRACE database[6], and only 11 of those localities have data on the median permit cost. Even among these 11 AHJs, the median direct permit cost ranges from $91.80 to $712.20. Several of these localities require more than one inspection, as well (*Permitting, Inspection, and Interconnection Data and Analytics*, n.d.).

A lack of data and statewide standardization reduces transparency in the installation process, increases the uncertainty of cost-recovery, and may negatively impact customer experiences. A nationwide survey conducted in 2014 revealed that about one-third of installers avoid jurisdictions with onerous PII processes, creating another barrier to DG (Cruce et al., 2022). While it is unknown the extent to which this avoidance behavior exists across Virginia, anecdotal evidence from interviews conducted for this report confirms that not only do PII costs in Virginia vary widely and are likely above the national average; but PII complexity and lack of transparency does burden installers, consumers, and localities.

In sum, evidence indicates that cost reduction through financial incentives disproportionately helps high-income residents and the impact on market penetration is unclear and context dependent. Moreover, the impact of soft costs, particularly PII and other transaction processes, is an integral aspect driving up DG costs and an area in which policy intervention can be beneficial.

Do Other Barriers Exist?

While this report focuses on cost reduction, additional barriers to DG exist for Virginians. For instance, homeownership and rooftop access are key impediments to solar take-up. Homeownership, income, and unshared roof space have all been found to be positively correlated with solar up-take (Briguglio and Formosa, 2017; Schaffer and Brun, 2015). This report also acknowledges that while reducing soft cost reduction improves solar affordability, low-income households are more likely to face additional barriers— such as the inability to claim tax credits, low credit scores prohibiting loan and leasing options, rooftops in need of retrofitting, lack of awareness and low community engagement, and mistrust of solar companies (Heeter at al., 2020). The shared solar programs of the VCEA are aimed at reducing these barriers by increasing access to renters and residents of multifamily buildings and allowing DG participation without system purchase and ownership. The regulatory functions of these legislative provisions need revision, but these are clear steps to improving clean energy access. Also, Virginia passed legislation to create green banks across the state, which will help support loan access, risk reduction, and other initiatives to engage Virginians of all socioeconomic statuses in the transition to clean energy (McGowan, 2021). Thus, this report focuses on efforts to reduce costs and inefficiencies; these other initiatives are encouraging and should be pursued in parallel with the recommendations presented here.

[6] This is one of the most comprehensive databases on PII timelines and costs.

Alternatives

The following section details the legislative details, timeline, and program components of three potential policy interventions.

Status Quo

No additional legislative action will be taken under this scenario, and all current policies, regulations and practices will serve as a baseline case. Given no state-level intervention, standardization in solar DG processes will not occur, and localities will continue to operate and reform their solar permitting, local zoning ordinances and solar practices as they see fit. The projected outcomes of the following two alternatives are made relative to the predicted trends of the status quo.

Alternative 1: State-Level Standardization of Permitting through SolarAPP

This alternative consists of creating legislation that mandates local governments adopt state-wide standardization, fast-tracking, and digital processing of permitting for DG systems 10 kW or less by January 1, 2024. Modeled after legislation passed in 2014 in California, this affirms "cost-effective installation of solar energy systems is not a municipal affair but is instead a statewide concern" (Assembly Bill 2188, 2015). Per this legislation, all AHJs in Virginia must adopt a streamlined, fast-tracked, and digital permitting process for small rooftop solar distributed generation systems (10kW or less— which would encapsulate nearly all residential and potentially some small commercial systems). To assist municipalities through this transition and ensure statewide standardization, use of a digital software (SolarAPP) would be required to facilitate this regulatory change.

To accommodate the heterogenous needs of Virginia's localities, the mandate models its roll-out after that of the Marcus-David Peters Act (HB 5043 and SB 5038), which passed in Virginia's 2020 Special Session. The Marcus-David Peters Act legislation created a mental health awareness response and community alert system to be adopted in all states by July 1, 2021. Like this alternative, the Marcus-David Peters Act was a statewide mandate of a new technological system and process. To accommodate the needs of more resource-constrained localities, additional time was allocated for them to comply with the mandate (HB 5043, 2020; SB 5038, 2020). A similar, two-year roll-out timeline and approach for SolarAPP would be adopted.

When a DG system is installed, it must comply with building codes, regulations, and local ordinances to ensure the safety of the infrastructure. At present, each AHJ in Virginia has its own permitting standards and processes. It is well established that the best practice for DG permitting is to create standardized, transparent, and fast-tracked processes, as this reduces costs and timelines for customers, solar developers, and municipalities and helps increase transparency and improve customer service experiences and accessibility in DG installations (O'Shaughnessy et al., 2021; Hsu, 2018; Ardoni et al., 2015; CAL SEIA, *n.d.*).

Several states have taken measures to streamline and standardize permitting and inspection processes across AHJs. As mentioned, California passed the Solar Permitting Efficiency Act

(Assembly Bill 2188) in 2014, requiring all city and county governments to adopt an ordinance that creates expedited, streamlined permitting processes for DG systems 10kW and smaller (Assembly Bill 2188, 2015).[7] Since the establishment of California's 2015 legislation, a digital software, Solar Automated Permit Processing (SolarAPP), has been developed and promoted by the Department of Energy. Development of a new standardized permitting process would take significant coordination, outreach, training, and discussion with AHJs if it were to be done entirely by the state of Virginia. Therefore, Virginia can leverage SolarAPP to help reduce local administrative burdens with compliance of this mandate.

SolarAPP was developed in 2018 by IREC and the Solar Foundation. This organization is also engaged in training, local government outreach, and other support for localities seeking to adopt this system. SolarAPP is an advanced online permitting tool developed in coordination with code officials, AHJs, and the solar industry. The software offers standardized plan review software that runs compliance checks and building permit approvals for solar rooftop systems. It integrates commonplace practices across other states, from New York to Texas ("SolarAPP+," n.d.).

SolarAPP is targeted at residential rooftop solar installations and is a free service for local jurisdictions. By automating permitting and standardizing up to 90% of DG system plans, local staff resources can focus on more complex solar projects, which are projected to increase across Virginia in coming years. Errors and compliance mistakes are caught and automatically resent to the customer, making it an accessible and flexible system for all parties ("SolarAPP+," n.d.). Furthermore, the system can stand alone or integrate with other government programs and inspection platforms, thus meeting jurisdictions where they are at technologically. Finally, by having the option for system upgrades, readily available resources, and trainings, and incorporating digital record keeping, localities can improve transparency and collect data on their own processes (*SolarAPP+ for Jurisdictions*, n.d.).

SolarAPP has also released a version, SolarAPP+ Storage, which reviews not only solar PV permits, but storage system permits as well. As energy storage emerges as a growing part of the distributed generation energy system, this feature could potentially be added to the locally adopted model, further boosting AHJ time savings.

Importantly, while SolarAPP program administers offer support to AHJs in implementing this system, compliance with this state mandate will nonetheless require up-front time and resources of the AHJs to realize the long-term time and cost savings. Virginia is a very heterogenous state, and it is likely that these administrative costs vary widely by locality. SolarAPP currently supports the national model codes (2018 I-Codes (International Residential Code, and Building code) for rooftop PV permit, 2017 National Fire Protection Association 70 National Electrical Code for rooftop PV permits), as well as inspection checklists and state and local license verification. Therefore, some localities with older codes and practices may need to review and update local permitting codes before this digital portal can be effectively leveraged. While this is a larger administrative hurdle, it also facilitates integration of modernization and best practices in local ordinances themselves.

[7] The average residential rooftop solar system is about 5 to 7 kW.

Alternative 2: State Incentive for SolSmart Partnership

This alternative creates legislation that helps support and incentivize a subset of localities develop a robust enabling environment to fosters more efficient and cost-effective solar growth. Specifically, this legislation provides a monetary incentive—in the form of additional grant funding for designated renewable energy spending—if a locality applies and successfully works with the federal SolSmart program. SolSmart is a nationally designated program led by the International City/Council Management Association and the Interstate Renewable Energy Alliance (IREC). The program is currently supported by the Department of Energy's Technologies Office. The program launched in 2016 and has helped over 400 cities, counties, and regional organizations across the U.S.

SolSmart provides free technical assistance to help communities set goals to institute best practices and remove obstacles to solar energy development. The foundational criteria of the program are in permitting and inspection and planning and zoning, with additional focus categories in government operations, community engagement and market development (*What Is SolSmart?*, n.d.). SolSmart advisors work alongside local officials to diagnose barriers and institute changes. Then, localities receive points based on the best practices and solar initiatives undertaken. Points help localities receive designation at gold, silver, or bronze levels (*What Is SolSmart?*, n.d.)

Similar to Alternative 1, this intervention leverages an existing network of technical assistance to help foster solar development. This alternative differs from the previous alternative (SolarAPP) in several key dimensions. First, unlike the mandate approach of the prior alternative, this intervention is voluntary and targeted. Second, SolSmart is more directly tailored to a locality's current needs and is more comprehensive in nature, including reforms and activities beyond just permitting. In addition to permitting fast-tracking and reform, SolSmart also encompasses technical assistance for reviewing permitting codes and processes themselves, which is particularly helpful for AHJs with more outdated and less solar-friendly policies. Furthermore, consultation to review other regulatory barriers (such as planning and zoning ordinances), optimize siting, and implement solar into community development plans reduces administrative costs and burdens of solar growth beyond permitting issues. For instance, a NREL study found a strong correlation between levels of installed solar capacity per capita and references to solar in the local code (Cook et al., 2016). Though a community may want to promote solar adoption among residents, failure to include solar installations in zoning code leaves installers vulnerable to lawsuits or other residents' potential oppositions. For instance, zoning codes typically specify permissible development (called a by-right), and without mention of solar in the by-right, this creates hurdles and uncertainty for potential DG customers. SolSmart helps localities diagnose and remedy these barriers (*SolSmart Program Guide*, 2021).

Additionally, community engagement programs and market development initiatives, through cost-savings programs like solarize group-by campaigns, make solar more affordable and accessible in an area, while saving AHJs time and resources as demand increases.

Since challenges are locally heterogenous and consultation can lead to a wider variety of intensive, pro-solar programs, this alternative would take a more individualized, voluntary approach to assist a smaller group of communities with greater need for reform, rather than adopt a state mandate.[8] To facilitate take-up of SolSmart among localities that may be historically solar-resistant, face the largest barriers to DG, have high demand, and/or are the most resource and personnel constrained to adopt these practices, additional grant funding will be used as an incentive. Grants will be allocated to 30 localities who consult with SolSmart partners and receive at least bronze designation status. Grants of $5,000 are anticipated to cover the cost incurred by AHJs in implementation, including officials' time, resources to update websites, conduct outreach, update ordinances, and/or undertake any other necessary SolSmart activities. To promote regional equity, a certain share of grants can be reserved for municipalities who have the "greatest need", defined by either a) average per capita income in the bottom quartile of the state b) demonstrated governmental resource constraint or c) another demonstrated unique local barrier to DG growth.

All localities will be encouraged to participate in SolSmart, as benefits in time and cost savings to local governments and promotion of clean energy goals can be achieved irrespective of receipt of the monetary state incentive. To promote evidence-based learning, the legislation will commission Virginia's Joint Legislative Audit and Review Commission (JLARC) to conduct a study on the 30 participating localities and produce a report on the reforms undertaken, AHJ cost savings, impact on solar growth, and other notable features of this program. The hope is that more communities will adopt best practices given demonstrated success among peer AHJs.

[8] High need for reform can be derivative of high solar demand, outdated practices or codes, lack of AHJ resources or knowledge, or other unique local barriers to DG.

Criteria and Methodology

The Piedmont Environmental Council (PEC) values policies that promote DG by making it more efficient, attractive, and accessible to Virginians. Furthermore, PEC highly values bipartisanship and feasibility of any proposed course of action. Lastly, PEC values civic engagement and community-driven initiatives. Guided by these core values, five criteria have been identified to operationalize the assessment of the alternatives.

1. Effectiveness (extensive marginal growth)
2. Net cost (intensive marginal benefit)
3. Political feasibility
4. Equity
5. Transparency

Effectiveness: Extensive Marginal Growth

Effectiveness at the extensive margin refers to the increase in the installed capacity of distributed solar generation (in megawatts, MW) above baseline projections. It is important to note that benefits from these alternatives may occur at both the intensive and extensive margins, and this analysis attempts to capture both effects. The extensive margin refers to the extent to which an alternative encourages new DG to be installed in Virginia. Reduced cost and time, positive customer experiences influencing neighbors' solar adoption, and fewer barriers to installation cause additional solar capacity to be installed. Consequently, the criterion of effectiveness measures the extensive marginal growth—the increased adoption of DG above and beyond baseline growth, measured as additional total MW of DG.

Net Cost: Intensive Marginal Benefit

Net cost refers to the total societal cost of an alternative, including all costs borne to key stakeholders in Virginia (residents, utilities, local and state governments, and solar developers). Costs include the administrative costs and labor hours of AHJs to implement programs, train staff, and reassess local codes. State costs include any incentive and support funding, as well as costs to collect data and produce reports. Any time, training, or resources otherwise employed by solar companies, utility companies, and other interested parties is also accounted for in the net cost calculation.

Through streamlining, standardization, easement of legal or administrative barriers and other activities, these provisions make DG cheaper per kW, ultimately producing cost savings. In other words, these alternatives save both residents and localities money, given the projected growth in DG in the coming decade. This is beneficial because it reduces societal deadweight loss, irrespective of new solar development occurring. The net cost captures the monetized net present value of this intensive marginal benefit, combined with all other total costs.

Political Feasibility

Given recent shifts in political control of the Virginia State Legislature and Governor's Office, as well as PEC's desire for bipartisanship, this criterion is crucial. In 2022, the Virginia House of Delegates flipped from a Democratic to a Republican majority (52-48). Governor Youngkin (R) succeeded Governor Northram (D). The Senate remains Democratic majority (21-19). Political feasibility is measured through a ranking system of "high", "medium", and "low." A rating of high indicates that the alternative is expected to be bipartisan in nature and will have a relatively high probability of passage in the next legislative session.

Both conversations with stakeholders and analysis of proposed policies and partisan activity in the 2022 Virginia Legislative Session inform the political feasibility evaluations. First, legislation that is similar in principle, policy, and/or stakeholder dynamics that has been recently proposed in the Virginia legislature is analyzed. Primary focus is given to the 2022 session, as this is most informative of current dynamics. Political affiliations of key patrons, voting history, overall result and lobbying efforts inform the likelihood that Democrats, Republicans, and other stakeholders (such as utility companies and/or local jurisdictions) will support the bill. Second, information gained in conversations with solar developers, advocacy organizations (such as Conservatives for Clean Energy and The Nature Conservancy), legislators, and program administrators add further context.

Equity

Equity broadly refers to the ability of all Virginians to access clean, affordable energy through DG. DG is an expensive investment but has potential for long-term financial payback and utility bill savings; it can also increase consumer choice in energy production. Equitable policies enable all Virginians who want to invest in this form of energy production, irrespective of socioeconomic status, to be able to do so. Importantly, equitable policies do not increase access in distortionary ways across the population. For instance, a tax credit may make DG more accessible, but only to those who have tax liability (i.e., higher income residents). As such, equity will be assessed for its ability to reduce costs, timeframes, or technical barriers in non-distortionary ways. Equity in this context is assessed across two dimensions: group-based distribution (income) and membership (service area).

Equity on group-based distribution asks, "Are Virginians of various income levels able to access DG equally?" Inherently, the answer to this question is no, due to the high up-front costs of DG. However, in reference to these alternatives, this report asks, "Does this intervention enable *more equal* DG access and distribution than current policy?" Membership-based equity asks, "Does this intervention consider the unique governmental capabilities socioeconomic differences across service areas?" A criterion that improves equity on both dimensions ranks "high"; a yes to one of these questions ranks as "medium", and an alternative that fails to advance equity on both dimensions receives a "low" ranking.

Transparency

This criterion refers to the accessibility and simplicity of DG installation, pricing, and negotiating processes between residents and business, AHJs, and third-party solar installation companies. Transparency is measured through a ranking system of "high", "medium", and "low." Alternatives that significantly improve the transparency of information about the costs, applications, installation steps, or other related processes between three or more of the stakeholder groups rank "high." Alternatives that increase transparency between two of the stakeholder groups rank "medium"; little to no increase in transparency and clarity in processes above the status quo rank "low." Consideration is also given to the scope of the alternative— are gains in transparency realized uniformly across the state, or do processes continue to vary by locality?

Evaluation

This section evaluates each policy alternative across the five criteria. The projected outcomes and a discussion of trade-offs are summarized in a table at the end of the section.

Status Quo

In 2020, Virginia had 187 MW of distributed solar, and 145.3 MW (77%) of this was net-metered. Recall that net-metering applies to systems 20 kW or less, which are predominately residential systems. Alternative 1 applies to systems less than 10 kW, while Alternative 2 applies to DG more broadly. While historical capacity data are available through the Virginia Department of Mines, Minerals and Energy, Virginia-specific projections of electricity generation from small-scale solar facilities are limited. Therefore, national data from the U.S. Energy Information Administration inform the status quo scenario in this analysis. It is assumed that the share of small-scale (net-metered) installed capacity will remain at 77% of total DG across the decade, which is relatively consistent with national projections (*Solar Market Insight Report 2021 Q4*, n.d.).[9]

The national growth rate in installed DG capacity in each year is used to project capacity growth in Virginia through 2033 (*U.S. Energy Information Administration*, 2021). These projections account for market trends such as changes in technology, federal policy[10], and fuel prices. The median projection is used, though scenarios with different parameters produce little divergence from the median case through 2050. Figure 5 shows the historical and projected DG net-metered capacity in Virginia. Historical data are represented by the dark green bars, from 2010 to 2020. Projected annual installations are shown from 2021 onwards. Note the large observed increase in installed capacity in between 2019 and 2020. This may be, in part, due to the provisions (and perceptions) of VCEA, though full impacts are unlikely to be realized that quickly. Applying the average national growth rates may therefore understate the projections in Virginia if projections were to continue along the growth rate observed from 2019 to 2020. The biggest implication of understating baseline DG growth is cost savings to AHJs may be greater than estimated in this report.

Detailed annual growth calculations and methodology can be found in Appendix B. Note that all alternatives' extensive and extensive marginal growth are estimated relative to the baseline scenario (i.e., above and beyond the status quo growth projections).

Since no action is taken under the status quo, no additional costs to the state, localities, utilities, or consumers are incurred. Deadweight loss from inefficient processes will persist to the degree to which localities take no further action. The political feasibility of this alternative is high, as no legislative action is needed. Transparency and equity both rank low since current barriers to solar DG persist.

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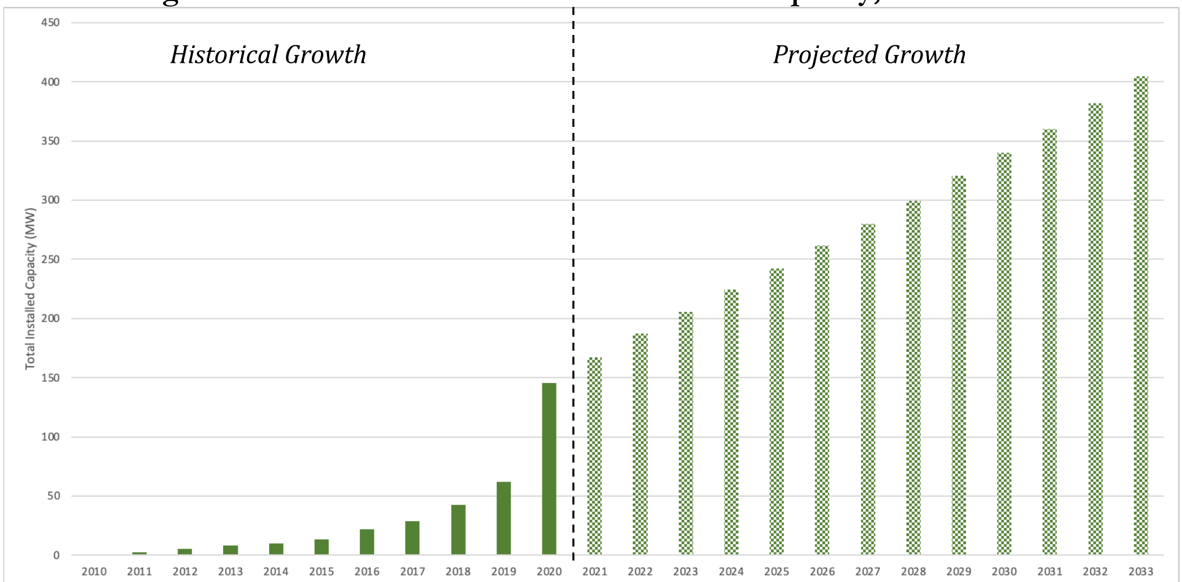
[9] The non-net-metered, or "commercial" share of DG encompasses DG solar systems with commercial, industrial, agricultural, school, government, or non-profits, excluding community solar.
[10] The federal ITC is set to expire for residential systems in 2024.

Figure 5: Annual Installed Net-Metered Solar Capacity, 2010 to 2033



Source: Author calculations, from Virginia Department of Mines, Minerals and Energy; U.S. Energy Information Administration

Alternative 1: State-Level Standardization of Permitting through SolarAPP

Net Costs: Intensive Margin

From 2023 to 2032, the net cost of this policy option is **-$7.61 million**. In other words, over the next decade, SolarAPP would have a net societal cost reduction of $7.61 million, driven by benefits accrued at the intensive margin. The cost savings to consumers through soft cost reduction drive most of the cost savings, at about $1.1 million in annual consumer savings. Total costs borne to the state of Virginia, local governments, solar contractors, and DG consumers are projected annually from 2023 to 2032 and aggregated. A detailed explanation of the cost calculations can be found in Appendix C.

Overall, evidence from a pilot study indicates that SolarAPP reduced permit and review processing to less than one day, resulting in a 12 day reduction in overall system adoption timelines (Williams et al., 2022). On average, SolarAPP saved 1.1 hours of local official time for each permit reviewed, plus 1.3 hours for every permit revision reviewed (Williams et al., 2022). In addition to AHJ cost-savings, research indicates that cost-savings accrue to DG consumers. Though beyond the scope of the SolarAPP pilot, a body of literature estimates the reduction in soft costs due to streamlined permitting processes. Cost reduction is driven by several mechanisms. Time saved by developers, increased cost certainty, and permit review time predictability help decrease labor and transaction costs. Plus, a week delay in permitting increases likelihood of project cancellation by 5-10%; cancellations waste resources and drive up costs for other customers (*SolarAPP: Cutting the Cost of Residential Solar*, n.d.). Additionally, one-third of solar developers nationwide reported either avoiding or charging premiums for installations in areas with burdensome local permitting and ordinance requirements (Wiser & Dong, 2013). SolarAPP addresses these issues.

Based on a meta-analysis of the literature and appropriate scaling to the Virginia context, this report assumes average cost savings of 3% of total system cost due to streamlined permitting, or $.0795/W. This is an average reduction in after-tax deadweight loss by $557 for an average 7-kW system, accrued as customer savings. In other words, the average DG system would be $557 cheaper. For complete discussion of the research on cost reduction due to permitting streamlining, see Appendix C.

A robust sensitivity analysis was performed. A lower bound estimate reveals the net cost to be -$1.42 million, while an upper bound estimates a net cost of -$106.29 million. These bounds are largely by differences in assumed consumer cost savings and are guided by the literature. Moreover, at the most extreme, even if the alternative did not translate into *any* DG consumer savings through price reduction, the alternative would still save money on net. AHJs save a total of $88,200 (an average of $3,200 per locality from 2026 to 2032) even *after* accounting for all their implementation and administrative costs. While not a significant total net savings in AHJ time alone, overall, this means that implementing this streamlined procedure would not induce long-run financial burdens on AHJs, all the while creating more efficient, solar-friendly solar acquisition market processes.

Effectiveness: Extensive Marginal Growth

This alternative is estimated to have a **negligible** impact on extensive marginal growth. Per the theory of change mechanism for this alternative, streamlined permitting increase solar investment due to lower costs, positive customer experience and peer effects, and government encouragement. While the impact of PII on prices is relatively robust (though variable), research estimating the second part of this mechanism— the impact of price reduction from streamlined PII on additional installed capacity— is mixed. There is evidence that cost reductions from subsidies increase DG development (Hughes & Podolefsky, 2015). For instance, Crago and Chernyakhovskiy (2017) estimate 3.2% more annual PV installments per a $0.1/W rebate increase. However, it is difficult to generalize these effects. Streamlined permitting is less obvious to consumers than rebate programs. Crago and Chernyakhovskiy explain that this might be the mechanism explaining why tax exemptions have more muted impacts than rebate programs, similar to the impacts and theories provided by Sarzynski et al. (2012).

Therefore, the literature on PII must be studied independently from other incentive programs. Krasko and Doris (2013) find that a one-step increase in a state's interconnection favorability score leads to a 6.2% increase in solar demand. This gives evidence that processes do matter for solar growth, but interconnection is a different process than permitting and involves the utility rather than the local government, so generalizing this result is again insufficient. Lin and Yi (2014) found no impact of city and state streamlined permitting on PV development, but this analysis did not consider implementation time and did not restrict the sample to residential systems. Hsu (2019) found a large association— localities with streamlined permitting have nearly 20% more solar installations. However, this impact is sensitive to model specifications and is not able to confirm causality. White (2019) cannot confirm that streamlined permitting impacts PV installation rates, though the author notes sparse data limits the analysis.

As such, due to challenges controlling for bias, data limitations, and weak evidence, it is unclear that there will be a sizable impact on PV development directly from SolarAPP. Though an effect may be present, it may be hampered by other governmental, utility, and/or institutional barriers aside from AHJ permit review (such as zoning, interconnection, inspection, etc.). Further, this may because the price reductions are accruing to consumers who would invest in DG irrespective of this policy, and therefore not encouraging new consumers to enter the market per se.

Political Feasibility

This alternative ranks **Low-Moderate** for the political feasibility criterion.

Climate change and renewable energy are historically partisan issues in the Virginia legislature. For instance, several proposed bills in the 2022 session are aimed at rolling back emissions standards and progress on climate mitigation measures (H.B. 73; H.B. 74; H.B. 118; H.B. 892; H.B. 894; H.B. 1301; H.B. 1204; S.B. 532), and incentivizing coal production (H.B. 656; H.B. 1326). These are largely carried by Republican legislators (*Virginia General Assembly 2022: Priorities for Environment and Energy*, 2022). On the other hand, there are a variety of clean energy bills (largely proposed by Democrats), and several pertain to DG. For example, H.B. 471 institutes solar-ready roof requirements for new construction of state agencies and energy-positive building design for schools. Sponsored by four Democratic legislatures, it failed to garner bipartisan support and died in committee (HB 471, 202.).

Some bills illustrate how legislators view authority, hierarchies, and decision-making power in energy matters. House Bill 723 supports transparency in electric cooperative governance (HB723, 2022). This bill failed to pass the House Commerce and Energy Committee. Similarly, House Bill 588 calls for SCC review and regulatory action in cases when rates set by investor-owned utilities are determined unjust and unreasonable (HB5888, 2022). This curbs Dominion and Appalachian Power's rate-setting power. This bill died in committee. Failure to advance these measures shows support of power concentration favoring utilities and status quo decision-making. This potentially foreshadows unpopularity of SolarAPP, which increase transparency and standardize processes.

Another proposed bill, HB 172, allows a locality in which a resident is seeking to install an energy project to restrict the visibility of the installation to "maintain the view of the surrounding community" (HB 172, 2022). This bill prioritizes AHJs discretion over resident rights to install DG in permitting and zoning matters and would conflict with the best practices of SolarAPP. Del. Marshall (R-14) was the chief patron; his district of Danville is in area in which resistance to this alternative would be anticipated. This bill was referred to the House Commerce and Energy committee but failed. It's failure to pass is a positive sign, but the Republican support of the bill indicates that Alternative 1 would face resistance.

Finally, interviews of several stakeholders conducted for this report provide illuminating perspectives. A discussion with the Energy and Climate Policy Manager for The Nature Conservancy in Virginia expressed enthusiasm at a cost-savings digital standardization mechanism for DG permitting like SolarAPP. Framing the alternative in a way to avoid the terminology of "mandate" may increase political feasibility. Nevertheless, a discussion with a representative from Conservatives for Clean Energy remarked that while a cost-savings framework has bipartisan appeal, a state-mandate is likely not going to gain Republican support. An interview with Del. Hudson (D-57) concurred that a mandate may be a "non-starter." Interestingly, Del. Hudson pointed to the bipartisan Marcus-David Peters Act, an act that mandated municipalities to change crisis response systems. This mandate gave smaller localities more time to comply with the act given their resource constraints (S.B. 5038, 2020; H.B. 5043, 2020). Even though this alternative provides a similar time extension for certain AHJs, an interview with a SolSmart program technical advisor in Virginia believed that many AHJs simply do not have the personnel or political will to implement permitting changes without state support; further, there are some rural districts that simply do not have the DG demand to warrant compliance. Without an enforcement mechanism, it is unclear if these areas would utilize SolarAPP

Finally, it is important to note that *any* legislation in support of distributed solar will face resistance from utility companies. The Nature Conservancy anticipated resistance from Dominion Energy, in particular. Hopefully, focusing on the AHJ-related processes of solar installation such as permitting (as opposed interconnection) lessens opposition from investor-utilities. Nevertheless, some lobbying against this bill by Dominion is anticipated.

Equity

This alternative's overall equity rank is **Low-Moderate**. Equity is analyzed along two dimensions.

1. <u>Group-Based (Income) Equity.</u> Reducing costs in a non-distortionary manner minimizes financial burdens and increase access for all consumers. Unlike tax incentives, overall system cost reductions are beneficial to all Virginians interested in going solar. Furthermore, those who cannot afford the upfront cost and thus utilize third-party ownership and/or finance DG through loan assistance also receive benefits of cost reductions, since loan and interest payments are reduced. Nevertheless, the size of this cost reduction may not be large enough to meaningfully remove financial barriers for low to moderate income consumers. A 3% reduction in price is substantive, but the cost of solar is still at least $10,000, and home-ownership is often necessary. Therefore, consumer-oriented equity of this policy is low.
2. <u>Membership (Service Area) Equity.</u> Several design constructs of this alternative aim to consider regional difficulty of compliance with a state-wide mandate. By applying to all AHJs, this policy helps move the needle in AHJs that may be more historically resistant to solar growth but have a growing consumer demand. However, often rural and lower-income AHJs have less resources and ability to comply with state mandates. The extra year of implementation time gives under-resourced areas flexibility to adopt SolarAPP on their own timelines. However, a mandate without state assistance will be a bigger cost burden for smaller, low-income areas than wealthier communities. Furthermore, this alternative doesn't consider current practices in areas with already efficient processes, potentially burdening these areas where the marginal benefit of SolarAPP over current permitting processes is low. Furthermore, greatest locality need pertaining to DG varies and may lie outside of permitting specifically, and this fails to address those needs.

Transparency

This alternative ranks **Moderate** for transparency. Statewide adoption of SolarAPP would significantly improve the transparency in a key installation process across all AHJs in Virginia. Automated permit checklists increase speed and efficiency of communication between local governments and installers. SolarAPP would provide transparency about process, expectation, and timeline to installers and consumers across the state. However, the scope of this alternative is limited to smaller systems and other institutional barriers and red tape may persist and vary by jurisdiction. Permitting is but one process in the DG installation pipeline. Interconnection, local zoning and ordinances, and inspection are among the other transactional processes involved in development and installation, and transparency of these transactions would be unaffected.

Alternative 2: State Incentive for SolSmart Partnership

Net Cost: Intensive Margin

From 2023 to 2032, the net cost of this alternative is **-$9.44 million.** In other words, over the next decade, this policy would have a net societal cost reduction in Virginia of $9.44 million.

Similar to the previous alternative, this policy intervention has a negative fiscal impact, meaning that the cost savings to localities and consumers are greater than the up-front costs of the grant incentives, time investments, and capital used for training and program implementation. An independent third party assessment of SolSmart efficacy found that, on average, SolSmart reduces permitting time processing by 7.5 days per installation (Canfield et al., 2021). O'Shaughnessy, et al. (2020) also confirm that SolSmart communities have, on average, 25% shorter permit review application times than non-SolSmart designated communities. While SolSmart designees' permitting reforms help speed up installation timelines, increase process efficiency, and foster solar development and consumer satisfaction, AHJ time-savings are relatively small to negligible. Nevertheless, cost-savings realized by DG consumers are substantive. The SolSmart report found that, across 58 SolSmart communities studied, statistically significant PV system price decreases were measured among bronze communities; solar soft costs by $.22/W due to SolSmart activities (Canfield et al., 2021).

A robust sensitivity analysis of cost savings was performed. Under the lower bound estimation, in which consumer savings are less than one third of those observed in the SolSmart analysis ($.06/W), the total net cost is still negative, -$1.94 million. An upper bound estimation, which is informed by price reductions consistent with other literature on regulatory and streamlining efforts, reveals a total net cost of -$24.26 million. At the most extreme, even if the alternative did not translate into *any* DG consumer savings through price reduction— which is unlikely given evidence from the body literature— the alternative would have a net cost of $208,000 across the coming decade.

For a detailed discussion of the cost calculations, sensitivity analysis, and research on cost reduction, see Appendix C.

Effectiveness: Extensive Marginal Growth

It is estimated that SolSmart participation will generate an additional **34 MW to 56 MW** in total installed solar capacity above status quo projections. This is a 6.9% to 10.3% increase in the total projected capacity of distributed solar in Virginia by 2032. Implementing best practices in permitting, zoning, outreach, and other strategies to improve cost-effectiveness and market readiness at the local level is demonstrated to foster solar growth.

Among 356 SolSmart communities, SolSmart designation causally increased installed solar capacity an average 69 kW per month, or about 3 new installations per community each month, above baseline growth (Canfield et al., 2021). The average additional solar capacity in each year is contingent upon the number of communities who have become SolSmart designees. Thus, this analysis scales the impact to account for program roll-out and uncertainty. For full details on extensive marginal growth methodology and calculations, see Appendix D.

Political Feasibility

This intervention scores **Moderate** for the political feasibility criterion.

The same concerns about partisan politics assessed under the previous alternative apply here. Again, HB 172 highlights the prioritization of AHJ discretion (HB 172, 2022). The benefit of SolSmart is that this policy options works with a locality to determine goals and actions unique to their jurisdiction. This allows for more heterogeneity than a state mandate model. Furthermore, state incentives are provided to nudge behavior, and at its core, the program is voluntary. These aspects garner bipartisan support. Plus, Southwest Virginia, a rural, Republican area, already has several SolSmart designees. This helps build statewide trust and support of program participation.

In an interview conducted for this report, Conservatives for Clean Energy expressed that a voluntary, incentive-based model highlighting cost-savings for residents and localities may be feasible, depending upon program details. A SolSmart Advisor consulted for this analysis also noted that several communities in Virginia that had preliminary consultations inquired about monetary benefits and/or grant funding from SolSmart participation, seeking support beyond technical advisory and inherent program benefits. This suggests that the incentive might be a favorable nudge for some communities. However, any legislation that involves state funds must go to appropriations, reducing the likelihood of passage. State costs are relatively small, though, (less than equivalent of the salary of one full-time employee for two years). Combined with voluntary nature of this policy option and its cost-savings framework, moderate political feasibility may be anticipated.

Nevertheless, fear of AHJ's losing autonomy and general political resistance from some Republicans, particularly those who sought to repeal VCEA provisions in the 2022 legislative session, is still anticipated. An interesting parallel from the 2022 legislative session is HB 998 and SB 452. These bills proposed that localities are permitted to incentivize and/or set requirements for building-owners to report and reduce energy use intensity (H.B 998, 2022; S.B. 452, 2022). This was referred to subcommittee but failed passage to the general body in both chambers. While the structure is different— in these bills local governments are incentivizing private building owners to change behavior, whereas the SolSmart alternative incentives localities to change behavior— the fact that a voluntary incentive program did not pass subcommittee evidence of potential resistance to this legislation if coalition-building, framing, and legal wording are not carefully considered. Plus, given that the SolSmart alternative is entirely voluntary in nature, it may be more bipartisan than these bills. Interestingly, the House version (HB 998), which was sponsored Democratically sponsored, was supported by five Republicans and one Democrat, but received rejection from three Democrats. The Senate counterpart fell on mostly party lines, with support from Democrats and rejection by Republicans. Hence, even seemingly environmentalist legislation may fall on unexpected party lines, given its perceived stringency (or lack thereof). If Democrats do not think it incentivizes the "right" action or that is not strict enough, then there is a possibility of resistance from this party as well.

Finally, the concerns regarding investor-owned utility resistance mentioned in Alternative 1 apply to this policy option, as well. However, unlike the first Alternative which applies to all utility service areas, the targeting of grants to higher-need areas may AHJs in cooperative utility service areas, thus not covering all of Dominion's service area. In this respect, anticipated utility resistance to DG legislation may be lessened due to the smaller scope.

Equity

The overall equity of this alternative is ranked **Moderate**. Equity is analyzed along two dimensions: with respect to consumer income class and jurisdictional need and capacity.

1. Group-Based (Income) Equity. Like the prior alternative, this intervention reduces solar soft costs in a non-distortionary manner (unlike tax credits) and can theoretically benefit all Virginians interested in going solar. While the estimated solar price reductions are larger than from SolarAPP— thus presumably making DG even more affordable— nevertheless, the size of the cost reduction may still not be large enough to realistically help low and moderate income residents install solar systems. However, this alternative may increase in equity in ways aside from price reduction. Community engagement, bulk purchasing, or installation of DG on public buildings are all within the scope of SolSmart practices, and these further reduce barriers and allow the benefits of DG to be realized by more community members. Yet, specific actions taken, and the prioritization and integration of equitable solar growth practices is left to the discretion of each participating locality.
2. Membership (Service Area) Equity. Since this alternative is voluntary, provides state-support, and prioritizes financing for areas with greatest need, regional equity is high. By designating portions of funding for lower-resource AHJs and/or areas with greatest need, it ensures that areas that currently have efficient solar provision and programs do not incur unnecessary costs and that higher resource areas do not receive grants for actions that they would have likely undertaken anyways. Therefore, regional equity is high.

Transparency

This alternative achieves **Moderate** transparency. In participating SolSmart AHJs, no two localities achieve designation the same way. However, three of the most common strategies utilized are reforms to permitting, updating planning, zoning and development codes, and community engagement. All three of these mechanisms clarify procedures, help increase communication between local governments, solar developers, and residents, and streamline and potentially digitize processes. Plus, AHJs can select the areas in which they need the most reform, maximizing transparency and best-practice take-up. Furthermore, bias in decision-making is minimized under this alternative because the practices undertaken are motivated by pre-determined principles and point systems run by the federal SolSmart initiative. For instance, local decision- and rule-making can be influenced by stakeholders' hesitancy to solar for either aesthetic or political reasons, or because of lack of technical knowledge. SolSmart reduces these conflicts, thereby increasing transparency in local institutions.

Additionally, nearly all SolSmart AHJs who responded to an impact survey reported increased government knowledge, nearly 70% reported increased community knowledge and 65% reported improved government/installer relations (Canfield et al., 2021). These factors reduce transaction costs and improve communication and transparency in the solar development and installation processes. However, despite the large positive impact on solar transparency, the scope of this alternative is limited. Only participating AHJs receive the benefit, so transparency increases are not realized uniformly across the state.

Outcomes Matrix

The table below summarizes the main analysis. Each alternative is presented with its projected outcome for each criterion.

	Effectiveness	Net Cost	Political Feasibility	Equity	Transparency
Status Quo	0 MW	$0	High	Low	Low
Alternative One	Negligible	-$7.61 million	Low-Moderate	Low-Moderate	High-Moderate
Alternative Two	34 MW to 56 MW	-$ 9.44 million	Moderate	Moderate	Moderate

Recommendation

Based on the projected outcomes of each policy option and consideration of the trade-offs, **Alternative Two is recommended as the best course of action.**

The second alternative, state incentivization of SolSmart, is projected to have more favorable intensive and extensive marginal impacts. SolSmart promotes solar development and reduces prices through a larger variety of mechanisms than SolarAPP, which only reforms permitting practices. Note that SolarAPP has larger savings accrued to AHJs than SolSmart, but the SolSmart alternative saves about $2 million more overall than SolarAPP due to larger savings to consumers (an average of $.022/W compared to $.0795/W).[11] This is consistent with the literature, which shows that PII reforms can reduce soft costs, but permitting *plus* other regulatory reforms (such as interconnection, zoning, and other mechanisms SolSmart leverages) produce larger savings because they address a wider array of barriers and processes in distributed solar development (Burkhardt et al., 2015). In its sensitivity analysis, Alternative 1 produces more cost-savings than the SolarAPP alternative in all scenarios except the most extreme, in which no consumer savings are generated from these activities. However, based on the literature, the likelihood of a failure to generate cost reductions for consumers is higher for SolarAPP than it is for the SolSmart alternative.

At the extensive margin, Alternative 2 outweighs Alternative 1. While SolarAPP is the "gold standard" for permitting, the evidence on the efficacy of permitting best practices translating directly to significantly increased DG take-up is mixed. Rather, it is likely that the cost savings and reduced deadweight loss accrue to individuals who would have invested in solar in the base case scenario, irrespective of policy intervention. Consequently, the estimated extensive marginal impacts of the SolSmart program are higher than the SolarAPP alternative. Nevertheless, extensive marginal benefits of SolSmart would not be realized across the entire state. This is not inherently a drawback, as incentivization and appropriate outreach may lead to growth in communities with the highest demand and/or need for SolSmart reform.

[11] Plus, the midpoint consumer savings for SolSmart are higher than even SolarAPP upper bound estimates ($.14/W).

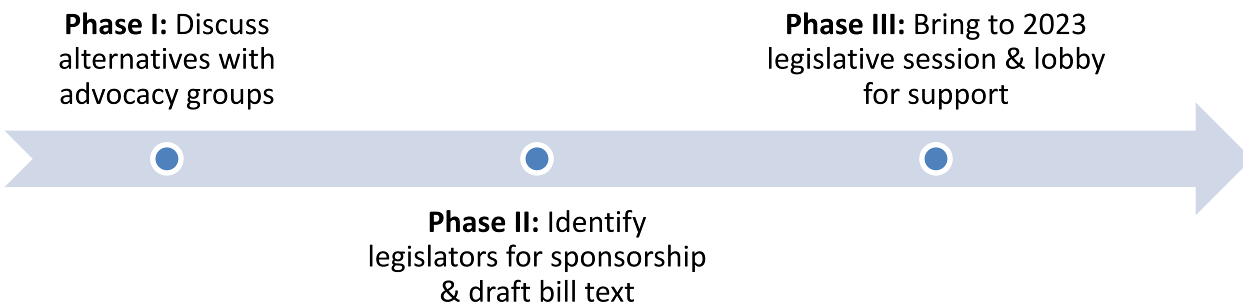
Regarding political feasibility, SolSmart is anticipated to be slightly more political feasible. The typical dynamics regarding climate change and utility resistance to DG will underpin both alternatives. The mandate-based approach of Alternative 1 is likely less feasible than the voluntary, incentivization nature of the SolSmart approach. On the flip side, the induction of state appropriations in the form of state grants and generating a report hamper feasibility of Alternative 2. Yet, based on stakeholder conversations, a statewide mandate seems to be a larger political barrier than minor up-front costs, particularly if long-run savings are emphasized.

Alternative 1 has a comparative advantage in transparency, but Alternative 2 ranks slightly higher in terms of equity.

Finally, while it may be moderately more politically feasible, its political viability rests on the framing and coalition-building undertaken to promote this bill. As such, careful consideration is given to this criterion in the adoption strategy detailed below.

Adoption Strategy

This section identifies a three-phase adoption strategy for the Piedmont Environmental Council to help foster the development of the recommended policy option.



Phase I: PEC should first initiate engagement with key advocacy organizations. This helps identify organizational priorities. The design and analysis of this alternative thoughtfully considered a variety of stakeholder perspectives. Nonetheless, political feasibility hinges on how the legislation is framed. When engaging with different groups, the priorities and benefits of this bill may vary. For example, Conservatives for Clean Energy emphasizes a voluntary approach and cost-savings benefits, while the Solar Workgroup of Southwest Virginia may prioritize and have skills in community engagement and equity aspects of SolSmart programs. Knowing and leveraging these vantage points during the lobbying of efforts of Phase III is critical. Moreover, these conversations build coalitions of support for this legislation. An initial list of stakeholder groups to contact includes:

- **Solar Energy Industry Association:** SEIA views permitting and soft cost reduction as one of its target policy priorities. Leveraging this industry network would be instrumental in gaining support for this alternative.
- **Virginial Municipal League (VML) & Virginia Association of Counties (VACO):** These organizations speak for the priorities and interests of localities. Understanding potential AHJ concerns and assuring the bill text meets these needs may be necessary for support. Conveying this bill maintains AHJ autonomy, saves money, and supports local officials to improve market efficiency will be important talking points in these conversations.
- **Conservatives for Clean Energy**: This group appeared initially interested in this policy option. Generating Republican support for this alternative is critical for political viability, and these stakeholders may share insight on helpful frameworks.
- **Appalachian Voices' Solar Workgroup of Southwest Virginia**: This organization successfully brought SolSmart designation to the seven counties in southwest Virginia. This network can generate evidence and support for SolSmart success, particularly in more rural, conservative, or otherwise high-barrier DG areas.
- **The Nature Conservancy:** While focused on USS siting on already-disturbed land in the 2022 Virginia legislative session, this organization is now looking towards distributed solar as an integrated part of their overall solar development strategy in Virginia.
- **Localities with SolSmart designation**: As of 2022, twenty-four Virginia localities already received SolSmart designation. Discussing the experiences of these communities can inform how to persuasively promote the legislation across different jurisdictions, to Democrats and Republicans alike.

Phase II: PEC convenes with legislators to identify potential sponsors and write bill text. While this list is not comprehensive, potential allied legislators include:

- **Delegate Tony O. Wilt (R-26):** Serving parts of Rockingham County and the City of Harrisonburg, he is a member of the Energy and Commerce and Agriculture and Chesapeake and Natural Resources Committees. Though voting against the VCEA in 2020, Del. Wilt demonstrated interested in facilitating solar projects by proposing legislation to expand community solar to Appalachian Power territory in 2022.
- **Senator Jennifer Boysko (D-33):** Serving areas of northern Virginia, she proposed SB 452 in 2022, creating the option for localities to adopt standards and incentive programs for energy efficiency. The structure of this bill shares aspects of the proposed policy option. Perspective on the sticking points of SB 452 in garnering bipartisan support will be informative.
- **Delegate Shelly Simonds (D-94):** Serving areas near Newport News, she is a member of the Agriculture, Chesapeake, and Natural Resources Committee. She sponsored HB 471 in 2022, which proposed requirements for solar-ready rooftops for state agencies and localities. A proponent of distributed solar, Del. Simonds may be a partner in this legislative effort.

Also, there will be several resistant stakeholders. As discussed, Investor-Owned Utilities, particularly Dominion Energy, are likely to oppose any effort to facilitate distributed generation. Given this opposition, highlighting that SolSmart helps *localities* reduce permitting, zoning, and outreach barriers to DG may lessen utility's opposition. Further, legislative resistance will exist, particularly from Republicans and districts who are a) resistant to renewable energy at large, b) concerned about state infringement on AHJ rights, and c) concerned about appropriations and utilizing taxpayer money for this effort. Thus, to mitigate this resistance, focus on the following features of this legislation:

- Efficiency improvement for localities and net cost-savings, especially for constituents
- Leveraging an already-existent federal program and minimal state funding needed
- Targeted, yet voluntary nature of the proposal

Phase III: PEC supports and lobbies for the legislation throughout the 2023 Legislative Session. PEC is familiar in partaking in these activities and has proven success in the 2022 session. These efforts include conducting stakeholder meetings, nurturing bipartisan partnerships, and working with constituents to garner support.

Implementation: Upon adoption, PEC can facilitate successful implementation of this program through its own programming and outreach. There are two target audiences for education and engagement around SolSmart designation. First, outreach to AHJs and officials who would benefit from participation would enable successful SolSmart implementation across the state. This includes the localities in the Piedmont region, but also expands to much of central and northern Virginia. Second, continued outreach and support of DG consumers in the Piedmont region is helpful. PEC already engages in this space, and continued delivery of information about solar developers, costs, and if DG is right for their home is extremely helpful. Communicating to constituents if their locality is a SolSmart designee or is in the process of achieving this status helps build public awareness of program success and additional resources available to them.

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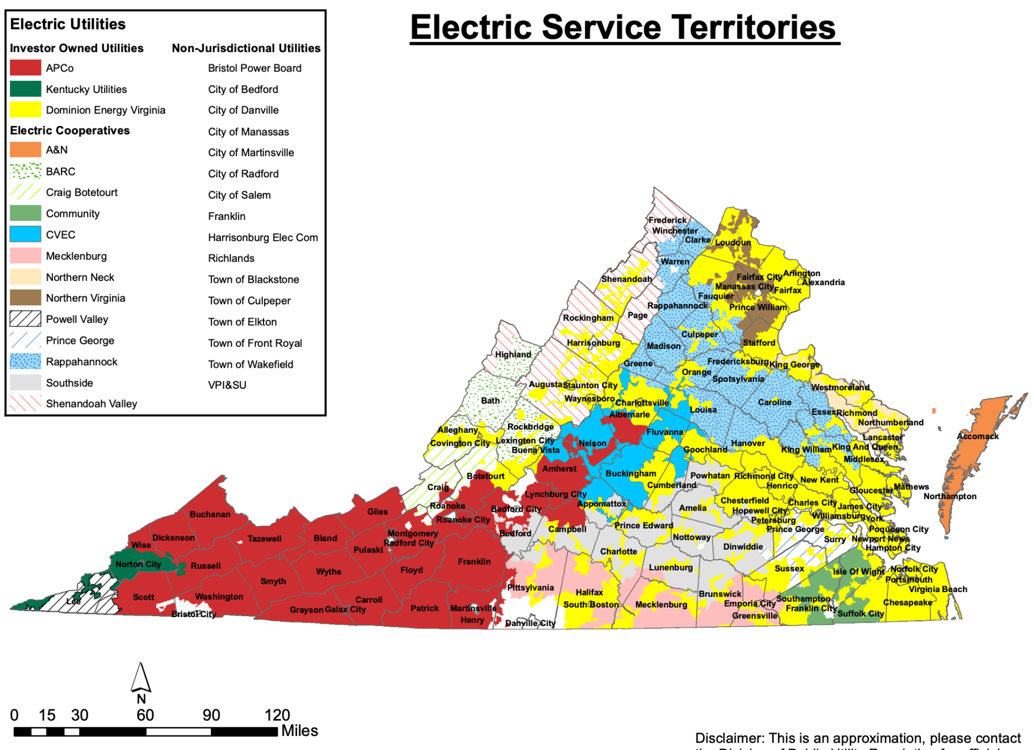
Appendix

Appendix A



Source: State Corporation Commission, 2020
Created by: Division of Public Utility Regulation, 2020

Disclaimer: This is an approximation, please contact the Division of Public Utility Regulation for official electric territory maps.

Appendix B: Status Quo Scenario

The table below shows the annual growth rate and projected total and net-metered capacity (77% of total DG in each year) in Virginia. The growth rate is based on the annual growth rate for installed capacity of distributed solar (*EIA Annual Energy Outlook*, 2021). The spreadsheet available at https://bit.ly/3uUboly provides a detailed breakdown of the status quo projections, in addition to detail on how this informs the alternative projections.

Year	Annual Growth Rate	Total DG Capacity	Net-Metered Capacity
2020		187.0	145.3
2021	15%	215.1	167.1
2022	12%	240.9	187.1
2023	10%	264.9	205.9
2024	9%	288.8	224.4
2025	8%	311.9	242.3
2026	8%	336.8	261.7
2027	7%	360.4	280.0
2028	7%	385.6	299.6
2029	7%	412.6	320.6
2030	6%	437.4	339.9
2031	6%	463.6	360.3
2032	6%	491.5	381.9
2033	6%	521.0	404.8

Appendix C: Cost Analysis

The detailed steps, assumptions, and methods utilized to calculate the net cost of each alternative is detailed here. The spreadsheet available at https://bit.ly/3uUboly provides a detailed breakdown of this work, including sensitivity analyses.

Time Horizon

This analysis uses a 10-year time horizon, from 2023 to 2032. The net present value of all costs is calculated, using a discount rate of 3%.

Scope

This analysis is scoped to the state of Virginia. All residents, localities, companies, and other stakeholders' costs that are within the state are considered. Costs borne to those outside this scope (e.g., the federal government) are not considered.

General Assumptions

The general assumptions are outlined in the "Major assumptions" tab of the spreadsheet, including links to primary and secondary sources that support these assumptions.

- Discount rate: 3%
- Average residential system: 7 kW
- Average Solar Panel Cost: $2.65/W
- Average Solar Specialist hourly wage: $24
- Average permitting/local government official hourly wage: $22
- Number of Solar Developers/Installation Companies: 72

Alternative 1: State-Level Standardization of Permitting through SolarAPP

The "SolarAPP" tab of the spreadsheet details the net cost calculations for this alternative. Costs are broken down by the stakeholder who bears the burden. The average up-front adoption, implementation, and training costs are monetized across 2023 and 2025. Cost savings are assumed to accrue from 2026 onwards and are monetized as outlined.

Information interviews with localities and solar companies conducted for this report suggest that the processes in Virginia are likely longer and costlier than the national average (and particularly of pro-solar California and Arizona jurisdictions willing to adopt SolarAPP during the pilot study), and thus cost-savings estimated in this analysis may be a low-end estimate.

<u>The State of Virginia.</u> Costs to the state of Virginia are negligible. A state-level mandate of permitting standardization in California determined in its impact statement to have a "negligible fiscal impact to the state" (Assembly Bill 2188, 2015).

<u>To Local Governments</u>. California AB 2188 also determined that the costs would be borne by localities, such that the second fiscal effect was "non-reimbursable costs to cities and counties to streamline their permitting processes and perform inspections in a shortened time frame" (Assembly

Bill 2188, 2015). This alternative in Virginia requires use of SolarAPP, so learnings from the pilot study of this software can be applied to estimate costs in Virginia.

SolarAPP software is free for localities and funded by federal and outside entities, thus the program maintenance and time spent by program specialists and developers training and advising localities as well as software development, maintenance, or system upgrade costs does not fall within the scope of this analysis— the state of Virginia.

However, the upfront costs borne by the localities in consulting with the SolarAPP program advisors, training on system usage, and implementing it into their processes is significant. These costs are calculated in the form of employee labor hours borne by the local officials. The SolarAPP pilot program found the 5 participating AHJs collectively spent 383 hours on SolarAPP+ implementation (Williams et al., 2022). This is an average of 76.6 employee staff hours per AHJ. It is important to note that this adoption time varied widely by local authority in the pilot study— ranging from 20 hours in Pleasant Hills, to 153 hours in Pima County. Similarly in Virginia, there will undoubtedly be heterogeneity in ease of adoption and implementation of SolarAPP. Nonetheless, an average estimate of local jurisdiction hours serves as an approximate estimate. Next, an assumed hourly wage of $22 for a local official is used (City of Charlottesville, 2022).

It is important to note that the SolarAPP pilot study focused on California and Arizona districts that were willing to engage in this process.[12] Therefore, they are not only voluntary and willing adopters, but not as resource and personnel constrained as many Virginia localities, particularly rural areas in the state. To generalize the pilot results more realistically to the Virginia case, additional costs for lower-income, more rural, and more resource-constrained localities are calculated in addition to the costs per average AHJ, informed by the pilot. Interviews with stakeholders and program administrators conducted for this report noted that some Virginia localities are hesitant to follow mandates, have not updated permitting and zoning codes in many years, and sometimes only have part-time staff who handle these matters. Combined with resistance to the program (whether due to political differences, the fact that their AHJ has low current DG demand and sees little need for streamlining, or from perceived threats of loss of local autonomy), this will likely add further administrative time and costs.

As stated previously, Virginia-specific data on DG penetration, current permitting and code standards, and costs of these processes is non-existent. Therefore, research on this topic inform the assumptions used. Cook et al. (2016) found that approximately 55% of localities do not mention solar PV in codes, indicating outdated zoning ordinances and permitting practices with respect to small-scale solar. Using this estimate, it is assumed that 55% of localities would have implementation cost burdens above the average costs observed in the SolarAPP pilot. It is difficult to know how much longer these processes would take and the additional resources needed (perhaps hiring a consultant, talking with other officials, upgrading internet services, etc.). Furthermore, given Virginia's limited access to broadband in some areas and anecdotal evidence with SolSmart program administrators, there are some localities who likely could not comply with this mandate within the first year, particularly without state support or funding (*Virginia Broadband Access*, n.d.).

[12] Several other localities have since adopted this model, including those in Maryland. Positive impacts were noted by other participating jurisdictions, evidencing that this model is generalizable. Adopting AHJs report similar time-savings as noted in this pilot, but a systematic data collection effort on adoption and impact was only undertaken in the five localities of the pilot study thus far. Thus, estimation of costs in Virginia are limited to this information.

Consequently, the roll-out design of the program is estimated from 2023 to 2025 in the following manner:

- 45% of localities (60 jurisdictions) would comply with the mandate and institute SolarAPP by 2024, incurring average costs similar to the pilot program
- 55% of local governments (53 jurisdictions) would incur costs twice that of the pilot program and roll-out program implementation over several years, by 2025.

Solar Contractors. The pilot study notes that contractors unfamiliar with SolarAPP required training on how to use the new digitized permitting system. Through the pilot, debugging occurred and processes were streamlined to be as user-friendly and easy to navigate for solar contractors as possible. There is a free webinar resource available to solar contractors (and a version available to solar inspectors) to demonstrate how to input residential rooftop permit applications into the SolarAPP tool and have permits issued for code-compliant systems.[13] This webinar and the certificate of completion issued on "How to Use SolarAPP" takes one credit-hour to complete. Therefore, it is assumed that it would take each employee one hour to receive training and answer questions to demonstrate knowledge of the system. It is assumed that 3 employees in across each of the 72 solar development and installation companies in Virginia would need to receive training in the first years of program rollout, 2023 through 2025. Using the average hourly wage of a solar developer, the annual costs of training time to solar companies' is estimated in the following equation (Glassdoor, 2022).

(1 hour) x (3 employees) x ($24 hourly wage) x (72 companies)

Cost Savings: AHJs. On average, SolarAPP saved local governments 1.1 hours for every permit reviewed, plus 1.3 hours for every permit revision reviewed. However, there are some localities that will upgrade their permitting systems to SolarAPP per the mandate (and incur the costs) but will not reap intensive marginal benefits because their permitting systems are already efficient. Detailed data on how many localities implement best practices at present do not exist. However, there are six counties that have already received SolSmart gold designation. To achieve gold designation, permitting turnaround must be 3 days or fewer. While SolarAPP may be a slight improvement over their current system, it is likely that not much time and cost savings is realized for these AHJs. The designated gold AHJs include some of the most populous areas; 19% of Virginia's population resides in a gold-standard area (*U.S. Census Bureau QuickFacts*, 2020; *SolSmart Designee Map*, 2022). As such, the cost savings are scaled to proportionately reflect that not all solar DG growth would generate intensive marginal benefits. To account for this, the number of DG installations that generate intensive marginal benefits is assumed to be 81% of total projected growth.[14] Cost savings to AHJs are calculated as in each year as:

[(1.1 hours) x (# DG permits) x ($22)] + [(1.3 hours) x (# DG permit revisions) x ($22)] x [133 localities x .81]

This yields total monetized savings of employee hours and efficiency for local governments. This report assumes 10% of systems require additional review (the review rate in the pilot study was 11%). Review is often due to project complexities; since SolarAPP automates review of incomplete

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[13] Trainings found at: https://cleanenergytraining.org/products/how-to-use-solarapp-for-rooftop-solar-projects.

[14] It is difficult to determine which systems will be installed in the six areas that will not see much incremental benefit from this alternative. As such, although it is estimated that only 4.5% of localities have best practices, population was used as a more accurate reflection of the share of solar growth occurring in these areas.

forms, time is saved contacting solar developers for missing, incomplete, or otherwise incorrect permit applications.

Cost Savings: DG Consumers (Price Reduction). Dong and Wiser (2013) estimate city-level impacts of streamlined permitting in 3,000 PV installation across 44 California cities. Their results indicate that the most favorable permitting practices (compared to cities with the most onerous permitting processes) reduce average residential PV prices by 4-12%, holding constant other factors. They also find installation time decreases in line with the results of the SolarAPP study. Using a much wider dataset across nearly 300,000 PV installation in the U.S., O'Shaughnessy et al. (2022) confirm that permitting, interconnection, and inspection (PII) processes and rates vary substantially by jurisdiction, and that PII reforms reduce solar installation timelines. Similarly, Burkhardt et al. (2015) find that local permitting procedures lead to price differences of $0.18/W between the jurisdictions with the most and least favorable permitting practices. Between jurisdictions in the middle range (comparing the 5th to 95th percentile jurisdictions), favorable permitting reduces average prices by $.14/W (2.2% of total system costs in a typical 5-kW residential PV installation). Since SolarAPP is designed to integrate with updated permit codes, the major components of the favorability scorecard in these studies would be satisfied with successful local adoption of SolarAPP.

Consequently, this report assumes cost savings due to streamlined permitting of $0.0795/W, which is 3% of total system cost, given the current national average solar panel cost is $2.65/W. This is an average reduction in deadweight loss of $556 for a standard 7-kW system, accrued as customer savings. Annual consumer savings due to PV installation price reduction is calculated as: (-$0.0795/W) x (1,000,000) x (projected MW growth), where[15] the projection of DG capacity growth is based on the status quo, in all years in which benefits are realized (i.e., 2025 to 2032).

SolarAPP pilot also found an average price reduction of permitting fees. Essentially, in response to time savings and expanded ability to process more permits, localities responded by reducing permitting fees, such that the net impact was an average reduction in costs to solar contractors of $6 per permit (even after accounting for the $25 SolarAPP fee per permit submission). Since this is a negligible impact and the disaggregation of mechanisms that cause overall price system reductions is beyond the scope of the report, this effect is not independently calculated. Using a single aggregate measure of cost reduction avoids double-counting benefits.

Sensitivity Analysis. A sensitivity analysis at an upper and lower bound was performed. Calculations can be found in the "SolarAPP- LB" and "SolarAPP UB" sheets of the spreadsheet found at https://bit.ly/3uUboly. For the lower bound estimate, the analysis assumed above-average costs were incurred in all localities (not just 53 AHJs, which is assumed for the main results). Additionally, a much lower rate of customer savings is assumed, $0.02/W. Soft cost reduction of $.02/W would be a quarter of the estimated cost savings assumed in the main analysis and is less than the average reductions found in the literature. Further, a discount rate of 7% was used. The conservative lower bound still finds net cost savings, with a total cost of -$1.64 million. For the upper bound, costs were assumed identical to the main analysis, but cost savings to consumers were assumed to be $0.14/W, and a discount rate of 1% was used. A price reduction of $0.14/W is based on the estimates found in Burkhardt et al. (2015). Under this scenario, net cost is over -$106 million, due to the large accumulation of customer savings each year (a total of about $15 million per year, which is an average of $980 per DG system).

15 There are 1,000,000 Watts in a Megawatt.

Alternative 2: State-Incentive for SolSmart Partnership

The "SolSmart" tab of the spreadsheet details the net cost calculations for this alternative. Costs are broken down the stakeholder who bears the burden. The average upfront adoption, implementation, and training costs are monetized across 2023 and 2026, accounting for rollout and increasing take-up of the program. Cost savings are assumed to accrue from 2024 onwards and are also scaled proportionately to program rollout.

State of Virginia. There are two main investments for the state government. First, the state will provide 30 localities with grants to help alleviate administrative burdens and incentivize program participation. Grant awards of $5,000 likely suffice in nudging positive behavior. This is a substantive monetary award; in addition to free technical assistance provided to qualifying AHJs through the SolSmart program itself, the grant should cover additional costs of SolSmart activities.

Second, the state would incur the costs of data collection, program evaluation, and drafting of a report on impacts of SolSmart improvements. Past legislation commissioning JLARC to conduct research for the state estimate no additional fiscal impact of these activities (HB170E, 2022; SB280, 2020; HB 903, 2016). JLARC studies requiring collaboration with other departments sometimes require additional funding; therefore, this analysis assumes a JLARC report on SolSmart effectiveness in Virginia will cost an additional $10,000 the year after program rollout is finalized, in 2026. A large share of the costs could be allocated within the existing JLARC capacity, but consultation with the participating localities and SolSmart advisors, as well as collection of program data is intended to have a slight additional fiscal impact on the state.

Local Governments. It is estimated that the awarded grants sufficiently cover the cost burden to localities. In the event that the entire grant is not used, the state can determine that other appropriate energy projects investments funding can be allocated towards.[16] Therefore, no additional upfront labor and investment cost is projected for 30 localities.

Presently, twenty-four municipalities in Virginia already received SolSmart designation. See Appendix E for the full list of designees. Once the state promotes this model and Virginia-specific evidence is garnered in the JLARC report, it is anticipated that additional communities will adopt SolSmart consultation and best practices, since they seek to gain the long-run benefits from this program. This report estimates 20% of remaining localities will participate in SolSmart without the incentive—an additional 16 municipalities. These 16 municipalities will incur upfront costs not offset by state government grants. Data on the time investment involved in SolSmart consultation and program commitment is not available. However, SolSmart notes that localities can expect, up to 100 hours of technical assistance from SolSmart advisors (Laurent, 2016). Costs to localities primarily include labor hours (personnel consulting with SolSmart advisors, revising local codes, etc.), but may also include capital costs for activities like website design, adoption of digital systems, and other outreach, depending upon the actions deemed necessary by the locality and SolSmart advisor to reach their designation goals. Therefore, 40 additional staff hours (on full-time week of

[16]Potential additional uses of grant funding may include providing DG rebates for or helping invest in DG on public buildings. The exact legislative wording could detail specific permissible uses of grant funding. It should be written that such investments should only be undertaken with funding remaining after offsetting any investment costs incurred during SolSmart participation and compliance.

labor) are added to the 100 hours in consultation with SolSmart advisors, to account for a high-end estimation of AHJ costs. Monetized AHJ labor hours are calculated as:

(140 hours) x ($22 hour wage) = $3,080

This is rounded up to $5,000 to also include any additional upfront costs not available in current budgetary resources. For reference, this estimate is about 1.5 to 3 times more than the estimated up-front investment costs per AHJ than SolarAPP, which is reasonable given that SolSmart covers a wider area of activities and programs than just permitting. The costs of SolSmart-adopting AHJs beyond the grant awardees is estimated to occur over two years, 2025 and 2026, once learnings from the JLARC report are disseminated to local authorities.

Operation and maintenance costs borne by localities are likely negligible, as permitting and zoning code updates and streamlining are up-front investments. For localities that undertake community engagement resources, website maintenance costs may be incurred, but again, the ongoing maintenance of these sources is likely minimal, as most of the cost is incurred in the initial investment in time and resources. Plus, the SolSmart consultation and technical assistance is free of charge to local governments.

Solar Contractors. Like the SolarAPP alternative, solar installation and development companies will need to learn new codes and permits, and any new software or processes that localities adopt. Ultimately, these practices will save time and promote growth in the solar industry, but there is nonetheless some minimal time investment spent by employees to learn changes. Given that data on these costs and impacts on the solar industry is limited, the cost calculation methodology used for the SolarAPP alternative is also used here: (1 hour) x ($24 hourly wage) x (72 companies) x (3 employees). These training costs are incurred in 2024 and 2025. Importantly, not all installers may need to undergo trainings, since not all companies service areas that will be SolSmart designees. Nevertheless, it is assumed that all companies undergo training, which is perhaps a high-end cost estimation.

Cost Savings: AHJs. Researchers used a propensity score matching and difference-in-difference approach to determine the causal impact of SolSmart designation on permitting timelines reductions. This study does not calculate the average hourly time savings per permit, as is done in the SolarAPP pilot analysis. However, gold SolSmart designation requires localities to have permitting review timeframes less 3 days; this is one of the largest barriers for attaining gold designation. Therefore, total cost savings due to streamlined permitting are assumed to be 25% of that in SolarAPP.[17] AHJ annual savings derivate of reduced employee hours and improved efficiency is calculated as:

[(0.275 hours per permit) x (# DG permits) x ($22)]

Since it is assumed that 46 total areas will become SolSmart participants, cost savings are scaled appropriately, and occur annually as programs rollout implementation.[18]

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[17] SolarAPP can be thought of as the "gold standard"; not all SolSmart designees will utilize this technology and instead streamline and standardize permitting in other ways. Assuming average permitting turnaround is 4 days for SolSmart designees (above the 3-day gold designation threshold), this is 4 times as long as SolarAPP, and so savings are estimated as-quarter of the average time-savings under the SolarAPP best practice.

[18] For instance, the baseline scenario projects there will be 3,073 new residential DG systems installed in 2024. Scaling this by 34.5% (since 46/133 AHJs will participate) will yield time savings for 1,060 systems. Now, it is probable that the DG growth will be concentrated in the areas that do adopt SolSmart best practices (as they are better resourced, have

Cost Savings: DG Consumers: As widely discussed in this report, a body of literature estimates soft costs reduction from PII reform. Furthermore, interviews conducted with government officials and solar developers reveal that improved government relations and inter-department coordination among local officials is one of the largest perceived benefits (Canfield et al., 2021). Research indicates the overall price reduction due to SolSmart activities is driven by bronze designation communities; these are typically communities with lower resources and higher barriers and red tape driving up soft costs. Bronze communities are similar to the localities that this intervention targets—areas with some solar demand, above average barriers to DG solar growth, and those that move from no recognition to bronze designation. Evidence indicates that across 58 SolSmart communities studied, bronze communities decreased solar soft costs by $.22/W (Canfield et al., 2021).

The price reduction estimated by (Canfield et al., 2021) because of SolSmart programs is consistent with Burkhardt et al. (2015) and Dong and Wiser (2013). For instance, Burkhardt et al. (2015) find that permitting procedure variations can produce system price differences of $.18/W, and broader regulatory variations can produce price differences of about $0.50/W. Thus, total savings due to PV installation price reduction is calculated in each year as:

($.22/W) x (amount of new installed solar, in W)

The trend for new DG systems is based on baseline growth projections. The status quo growth is scaled by 34.5% to account for the share of growth that occur solely in designated SolSmart AHJs.

A robust sensitivity analysis of cost savings was performed and can be found in the "SolSmart- LB" and "SolSmart- UB" sheets of the spreadsheet found https://bit.ly/3uUboly. At the lower bound, customer savings of $0.06/W and discount rate of 7% are used. Soft cost reduction of $.06/W would be a quarter of the estimated cost savings found by Canfield et al. (2021). The maximum total net cost is -$1.94 million under the conservative scenario. At the upper bound, cost reductions of $0.509/W are used, informed by Burkhardt et al. (2015), which found that broader regulatory changes, like SolSmart, cause price differences of $0.50/W between jurisdictions. Other model specifications in this paper indicate that potentially between 9-13% of cost reductions between 2011 and 2012 in their data are attributable to permitting and other local regulatory changes. Using an upper bound cost reduction of $0.50/W and a discount rate of 1%, this alternative would have a net cost of -$24.26 million. This translates to consumer savings of about 8% of total DG system costs, or $3,500 of a typical 5-kW system.

Appendix D: Extensive Growth Calculations

Alternative 2: State-Incentive for SolSmart Partnership

Research estimates that "SolSmart increases installed capacity by 69 kW/month, or 3 systems/month, on average in a community" (Canfield et al., 2021). Two methodologies are used to calculate an upper and lower bound for the total solar growth due to SolSmart designation. It is important to note that this effect holds for the gold and silver designees but is weakly estimated for

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higher demand for solar at present, and likely have more pro-solar sentiments). However, this distribution of growth within the state is unknown and imprecisely modeled. Hence, cost savings are scaled by the overall share of VA localities who undergo reform under this intervention.

bronze designees. Currently, 11 out of the 24 SolSmart communities in Virginia (42%) have reached gold or silver status. It is likely that more AHJs will be able to reach silver or gold status with state-governmental support. Therefore, to scale the magnitude of this effect appropriately, it is assumed that 50% of participating localities will reach above bronze designation, or 23 of the 46 newly participating AHJs. Therefore, annual extensive marginal growth is calculated as:

(69 kW per month) x (12 months) x (23 SolSmart communities)

The average additional solar capacity in each year is contingent upon the number of communities who have become SolSmart designees, and thus the analysis scales the impact according to roll-out. (Canfield et al., 2021) projected this growth in the short-term (1.5 years), but it is unclear how long this effect persists in the long-run. The data were insufficient at the time of analysis to project outcomes over a longer time frame. Therefore, though it is likely that growth at the extensive margin may persist several years after program implementation, this report estimates growth in the amount of DG solar capacity installed above the status quo for 2 years after full program rollout for a community (until 2027). While this may be a low-end estimate, nevertheless, it is estimated that SolSmart participation will cause 56.3 kW in total installed solar capacity. This is 10.28% increase in the total projected MW capacity of distributed solar in Virginia by 2032.

(Canfield et al., 2021) claim that a 69 kW is the same as an average increase of 3 installations per month in a community. 69 kW per 3 installations would indicate that each system is 23 kW, which is above the typical residential system size range from 3 to 10 kW. Therefore, it is likely that SolSmart increases commercial DG installations and installations on public and government buildings. This is likely why gold and silver communities have the larger effect— they are better resourced and can afford investment of DG in public areas and/or have businesses that can invest in DG. Thus, a lower-bound estimate is also calculated. If the three new installations per month were residential, then this would equate to: (7 kW) x (3 systems) = 21 kW/month of new solar. Using this kW estimation across the same timeframe as the first methodology, this produces a lower bound estimate for the total extensive marginal growth in installed DG capacity of 34.02 MW by 2032.

Appendix E: Current SolSmart Designated Communities in Virginia

Community	**SolSmart Designation**
Albemarle County	Bronze
Alexandria	Gold
Altavista	Bronze
Arlington County	Bronze
Blacksburg	Silver
Charlottesville	Silver
City of Fairfax	Bronze
Dickenson County	Bronze
Fairfax County	Gold
Falls Church	Silver
James City County	Bronze
Lee County	Bronze
Loudoun County	Silver
New River Valley Regional Commission	*Bronze*
Newport News	Bronze
Northern Virginia Regional Commission	*Gold*
Norton	Bronze
Pulaski County	Gold
Richmond	Gold
Roanoke	Bronze
Russell County	Bronze
Scott County	Bronze
St. Paul	Bronze
Tazewell County	Bronze
Williamsburg	Silver
Wise County	Gold