CURRENT
ENERGY GROUP

Value of Distributed Energy Resources in Virginia

An Assessment of Benefits and Cost-Effectiveness

Prepared for Solar United Neighbors

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1 Executive Summary

Virginia is anticipating some of the fastest-growing electricity demand in the nation. At the same time, traditional supply-side resources face rising costs and significant development delays. Advances in Distributed Energy Resources (DERs) technology, business models, and regulatory frameworks now allow such resources to be deployed at scale, enabling the Commonwealth to meet projected load growth reliably and affordably while continuing to advance its decarbonization goals.

Virginia has recognized the value of DERs through the 2020 Virginia Clean Economy Act (VCEA) and the 2025 Community Energy Act. This report builds upon those policy frameworks to detail the role that DERs can play in addressing Virginia's energy system needs. While not exhaustive, the report presents an analysis of the benefits of DERs, as well as the opportunities and actions that need to be undertaken to unlock their full value. The report is organized as follows:

- Benefits of DERs by Technology Type (Chapter 2)
- Cost-Effectiveness of a Near-Term Portfolio of DERs (Chapter 3)
- Implementation Risks & Policy Recommendations (Chapter 4)

What are Distributed Energy Resources (DERs)? DERs are small- to medium-scale energy technologies that generate or store electricity close to where consumers use it or through local sharing agreements. Common types of DERs include community solar systems, rooftop solar panels, battery energy storage systems, and electric vehicles and their chargers. Energy efficiency upgrades (that reduce total energy use) and demand response technologies (that manage or reduce energy use during peak times) are also forms of DERs. When DERs are aggregated and coordinated via software-based orchestration tools, they are referred to as a Virtual Power Plant (VPP). VPPs are coordinated with grid operations, providing the same kind of reliability and economic value to the grid as traditional power plants.

Table 1. Distributed Energy Resources Evaluated in this Report

DERs Type	Key Technologies	Deployment Scale	Primary Function
Energy Efficiency (EE)	LED lighting, HVAC upgrades, smart thermostats	Customer	Reduces overall demand
Demand Response (DR)	Load shifting notifications & incentives	Customer	Shifts peak demand
Front of meter (FOM) Solar/Storage	Utility-scale, shared solar arrays and battery storage systems	Utility-Scale	Generates and/or stores energy directly to grid (not direct to end users)
Behind the Meter (BTM) Solar/Storage	Rooftop solar, home batteries	Customer	Generates and/or stores energy either directly to end users or via the grid
Virtual Power Plants (VPPs)	Software to aggregate connected technologies	Customer-Aggregated	Technology to aggregate and coordinate DERs

1.1 Key Findings

The benefits from DERs come from multiple value streams and proliferate throughout Virginia's economy (Chapter 2).

DERs offer a compelling opportunity to meet electric system needs. Beyond cost savings, DERs provide additional non-monetized and risk-mitigating benefits. Their rapid deployment and modular design increase planning flexibility and reduce development risk if future conditions, such as load growth, commodity prices, and/or carbon policy deviate from current forecasts and assumptions. DERs can democratize energy participation, empowering customers while enhancing localized resilience to disruptive events. By displacing fossil fuel generation, DERs reduce air pollution and greenhouse gas emissions, improving public health across Virginia. In addition, weatherization and appliance upgrade assistance result in enhanced comfort and livability, particularly when integrated with low-income assistance programs.

Compared to traditional utility-scale resources, DERs can more effectively advance energy equity by localizing and concentrating benefits within the communities that need them the most— including low-income communities and those with high energy burdens, less access to modern energy infrastructure, and/or disproportionate exposure to pollution. Because DERs are modular and flexible, programs can be intentionally designed to direct participant benefits and structure incentives to prioritize specific populations or geographies.

Table 2. Summary of Benefits of DERs

Utility System Benefits		Participant Benefits	Societal Benefits
Avoided capacity costs (generation, transmission, and distribution)	Resource diversity and reduced fuel costs risks	Lower electricity bill & cost assistance	Avoided greenhouse gas & air pollution emissions
Avoided energy costs	Modular build & "right-sizing" investments	Increased comfort/ livability	Brownfield development potential
Ancillary Services (voltage and frequency regulation)	Rapid deployment capability	Resilience through disruption events	Reduced land footprint & aesthetics
System resilience (reduced outage risks)	Reduced planning risks ("just-in-time" investments)	Democratization and energy empowerment	Economic contributions (jobs, labor income, output, tax revenues)
Renewable integration (reduced curtailments)	State policy compliance Leveraging private capital	Access to data and enhanced control	Workforce readiness for the energy transition

Accelerating deployment of DERs is a cost-effective strategy to meet near-term load growth, with net savings compared to fossil-fuel alternatives (Chapter 3).

In its 2025 Integrated Resource Plan (IRP) Update, Dominion Energy projected a 2,600 megawatt (MW) capacity shortfall by 2031 (absent additional new capacity resources).[1] DERs could help address large portions of this and other projected shortfalls in the Commonwealth, while also creating additional benefits for ratepayers and mitigating risks compared to fossil fuel resources.

The analysis examines a portfolio of incremental DERs (Table 3) that are feasible in the near-term based on existing statutory requirements under VCEA and the VPP Pilot program as envisioned by the Community Energy Act. Because requirements apply to Phase I (Dominion) and Phase II (Appalachian Power) utilities, the DERs portfolio as defined herein for Virginia is technically inclusive of only these two utilities (approximately 90% of Virginia's electricity customers).

Table 3. Virginia's Near-Term DERs Portfolio

With expanded investments, Virginia could have a DERs Portfolio of:		
	Current	**2028**
Energy Efficiency	1.6 GWh	4.0 GWh
Distributed Solar (<1 MW)	600 MW	1,100 MW
Distributed Solar (1-3 MW)	40 MW	400 MW
Distributed Battery Storage	7 MW	22 MW
Virtual Power Plant (VPP)	0 MW[2]	450 MW

The cost-effectiveness analysis evaluates a near-term portfolio of DERs relative to fossil-fuel alternatives.[3] The near-term DERs portfolio would provide the **same reliable capacity as a 950 MW new peaking natural gas plant**. Unlike a new gas turbine that needs 5 to 7 years for development,[4] DERs can be rapidly deployed and built modularly to right-size investments to needs—with the added benefit of not increasing greenhouse gas emissions or air pollution from fossil fuels.

The near-term portfolio of DERs delivers $606.1 million in annual monetized benefits against $317.9 million in annual costs, resulting in **$288.2 million in annual net savings and a cost-effectiveness ratio of 1.91**. Benefits are categorized in capacity and energy value streams: avoided

[1] Dominion Energy, "Virginia Electric and Power Company's 2025 Update to the 2024 Integrated Resource Plan", *Virginia SCC Case No. PUR-2025-00184*, (October 15, 2025), Appendix 2B-9, Figure 2.1.9. https://cdn-dominionenergy-prd-001.azureedge.net/-/media/content/about/our-company/irp/pdfs/2025-integrated-resource-plan-update.pdf.

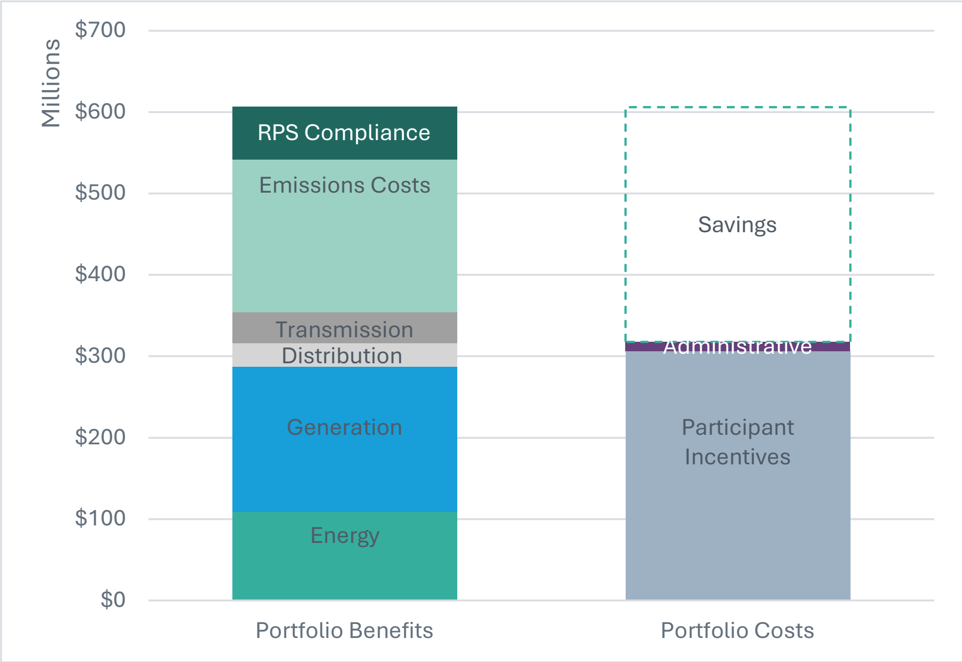
[2] While there are approximately 68 MW total of existing demand response (DR) resources, behind-the-meter (BTM) batteries, and electric vehicles (EVs) in Virginia, they are not aggregated into a VPP program where they can be dispatched uniformly. Accordingly, the value of existing VPPs in Virginia is zero. Including the existing DERs, the 2028 VPP portfolio would be comprised of approximately 380 MW in net new participating resources.

[3] Notably, the cost-effectiveness test is not the same as the utility, participant, and societal benefits described above; for example, a participant incentive payment is both a benefit for participants as well as a cost for the utility.

[4] Jared Anderson, "US gas-fired turbine wait times as much as seven years; costs up sharply", *S&P Global* (May 20, 2025), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

generation capacity totals $175.8 million, while avoided transmission and distribution add $38.3 million and $28.4 million, respectively. On the energy side, the portfolio results in energy savings of 3.8 million MWh, yielding $113.2 million in avoided energy costs, $187.2 million in avoided emissions costs, and $63.2 million in RPS compliance value. Figure 1 displays the magnitude of the cost-effectiveness test components and resulting savings.

Figure 1. Annualized Cost-Effectiveness Results



For the 3.2 million customers served by Dominion and Appalachian Power,[5, 6] the $288.2 million in annual savings indicates that **adopting the near-term portfolio of DERs will save the average customer up to $90 dollars per year.** These values reflect only monetized benefits; the additional benefits of distributed resources include other important values that are not monetized (as summarized by the benefits listed in Table 2 above).

A more restricted view of cost-effectiveness, which considers only benefits from avoided infrastructure elements, underscores the robustness of the results. **Considering only the benefits of avoided costs for energy, generation capacity, transmission, and distribution—excluding avoided costs for emissions and RPS compliance—still results in a cost-effective portfolio, yielding annual savings of $37.8 million.**

[5] Dominion Energy, "Economic Development Virginia", https://www.dominionenergy.com/economicdevelopment/virginia.
[6] American Electric Power, "Virginia Economic Development", https://www.aep.com/economicdevelopment/regions/virginia/.

1.2 Summary of Recommendations

This report finds that Virginia can cost-effectively deploy a significantly larger portfolio of DERs in the near term (than currently deployed), providing substantial energy, capacity, and system value as early as 2028. Achieving this depends on taking a number of steps to eliminate barriers and unlock the full value of DERs. **The primary barriers to near-term success are not technical or economic, but institutional—stemming from policy design, program implementation, and utility incentives that are misaligned with least-cost, highest-value system outcomes.**

To unlock the full value of DERs and meet Virginia's growing energy needs cost-effectively, this report recommends:

1. **Strengthen and expand the VPP Pilot.** The current VPP Pilot is an important first step, but it should be enhanced to demonstrate full system and ratepayer benefits.
   - Increase the size of the aggregator component in the VPP Pilot program to pave the way for a robust permanent program with ambitious procurement targets.
   - Strengthen the VPP Pilot by prioritizing automated offerings that dispatch virtually, building upon the success of manual demand response programs like Peak Time Rebates.
   - Establish clear pathways for expansion to additional service territories, such as a 50 MW VPP Pilot for Appalachian Power.
2. **Address barriers to deployment by modernizing regulatory and utility structures that currently constrain DERs growth.** Virginia can expand DERs integration to capture additional system benefits.
   - To ensure progress prior to 2035, add interim requirements for small-scale solar and BTM battery storage to align with the utility-scale interim targets.
   - Ensure all utilities recognize DERs & VPPs using appropriate capacity accreditation that reflects their performance and reliability contributions, ensuring they are recognized on equal footing with conventional resources in resource planning and capacity markets.
   - Uphold the spirit and letter of the VCEA and Community Energy Act by not allowing backsliding on targets and enforcing disallowances or other penalties for underperformance.
   - Allow large loads to directly fund DERs programs. Authorize the SCC to open proceedings to create a DERs compensation scheme.
   - Remove or increase the distributed generation (DG) caps. The current limits restrict cost-effective customer participation and stunt the market for DERs.
   - Establish minimum DERs deployment levels, interim targets, and incentives for disturbed lands (parking lots, brownfields, landfills) to accelerate Virginia's brownfield priorities.
   - Ensure fair DERs compensation for the value provided to the grid to expand access and improve customer equity while maintaining grid cost recovery.
   - Identify and implement needed distribution system upgrades and advanced grid functions to enable dynamic DERs integration and participation.
   - Develop a set of targeted performance-incentive mechanisms (PIMs) to incentivize utilities to meet DERs targets and address utility biases that impede DERs deployment.

2 Benefits of Distributed Energy Resources

DERs deliver a wide range of benefits to Virginia's electric system, its customers, participants, and society at large. These benefits span multiple dimensions—some can be quantified and monetized, while others are best described qualitatively. Understanding the full spectrum of values is essential because these resources represent more than incremental improvements to the grid; they embody a paradigm shift in how energy is produced, stored, and managed—and thus result in new, additional value streams compared to traditional utility-scale resources.

Historically, electricity customers have been passive consumers of energy. DERs change this dynamic by enabling customers to become active participants in a decentralized, flexible, and sustainable energy ecosystem. Through technologies such as rooftop solar, battery storage, energy efficiency, and demand response, customers can generate their own electricity, reduce consumption, and provide grid services that enhance reliability and resilience.

This section begins with an overview of DERs technologies and then explores the benefits they provide in detail.

2.1 Overview of DERs Technologies

DERs are defined as small- to medium-scale energy technologies that generate or store electricity close to where it is used, such as homes, businesses, or communities.[7] Common types of DERs include rooftop solar panels, battery energy storage systems (BESS), small wind turbines, combined heat and power systems, electric vehicles and chargers (when used as grid resources) and demand response technologies (that manage or reduce energy use during peak times).

The specific types of resources and technologies that are evaluated in this report include both behind-the-meter resources (those on the customer's side), front-of-meter resources (those on the utility's side), reduced or shifted energy use, and aggregations of these resources. The specific technologies are as follows:

Behind-the-Meter (BTM) Resources:

- **Distributed Solar** refers to solar energy systems that are located close to the point of use, such as a residence or business, rather than at a centralized power plant. These systems are typically installed as panels on rooftops or small ground-mounted arrays and are often owned or leased by households or other individual entities. These systems are sometimes connected to the grid in a way that allows for two-way ("bi-directional" or "hybridized") energy flows back to the grid, else used to power onsite electricity.
- **Distributed Storage** refers to energy storage systems, such as batteries, which are installed at or near the point of energy generation or use. These systems can store both electricity generated on-site (e.g., by rooftop solar) and electricity from the grid (if bi-directional). The stored electricity is then discharged later to meet the customer's needs, improve reliability and resilience, or support the larger grid. Distributed storage can also include electric vehicle

[7] Under current Virginia law, a DERs is defined as up to five MW. Virginia General Assembly, *An Act to direct certain electric utilities to petition the SCC for approval to conduct a virtual power plant pilot program*, H.B. 2346, 2025 Sess. (Va. 2025), https://lis.blob.core.windows.net/files/1055797.PDF.

batteries when they are set up with a two-way system to discharge back to the grid (i.e., "vehicle-to-grid").

- **Distributed Solar + Storage** refers to a system that combines solar power (typically from solar panels) with energy storage (typically batteries). The storage resource stores electricity generated during the day for use when solar production is low or demand is high (e.g., at night or during power outages).

Front-of-Meter (FOM) Resources:

- **Shared Solar and/or Storage** are FOM resources that, unlike BTM solar and/or storage, are installed on the utility's side of the meter but shared collectively by customers. They can be either privately owned or owned by the utility and leased to customers. Also referred to as "community" solar or storage, or both, these resources are commonly located on disturbed lands like parking lots, brownfields, landfills, agricultural lands, and adjacent to highways.[8]

Reduced or Shifted Energy Use:

- **Energy Efficiency (EE)** refers to reducing electricity use by using less energy to perform the same task. It generally involves replacing energy intensive equipment with more efficient alternatives. Common EE measures for commercial and industrial customers include replacing heaters, boilers, and machinery. Residential EE can incorporate home weatherization and upgrades, including water heaters, smart appliances, and heat pumps.

- **Demand Response (DR)** refers to behavioral incentives to shift energy use to reduce peak demand for electricity. Demand response programs either ask or offer incentives to customers to reduce their electricity use during certain times of day or when notified during an event. Demand response can either be automated through software that enables the utility to make the change directly or manually by the customer. Technologies that offer automatic demand response include smart thermostats, EV managed charging, and other controllable loads (water heaters, pools pumps, other commercial energy uses).

Aggregation of Demand-Side Resources

- **Virtual Power Plant (VPP)** is a network of aggregated distributed energy resources that are coordinated through advanced software to act like a single power plant. Either a utility or a third-party aggregator can enroll customers and coordinate the operation of the VPP. The types of resources that can be used for VPPs include: smart thermostats, electric water heaters, battery storage systems (with or without rooftop solar), electric vehicles, electric vehicle chargers (bi-directional or not), and all other curtailable residential, commercial, industrial, and agricultural loads. A VPP can either be owned and/or operated by the utility or contracted through a third-party provider. VPPs are also referred to as distributed power plants (DPPs), DERs aggregators, and other similar names.

[8] A related technology is "small-scale" renewables, which generally refer to wind or solar less than 3 MW. While these can have similar ownership structures to community resources, they are often owned by individual entities rather than collective entities.

Table 4. Summary of DERs Resources & Technologies

DERs Type	Key Technologies	Deployment Scale	Primary Function
Energy Efficiency (EE)	LED lighting, HVAC upgrades, smart thermostats	Residential/ Commercial	Reduces overall demand
Demand Response (DR)	Load shifting notifications & incentives	Residential/ Commercial/ Industrial	Shifts peak demand
FOM Solar/Storage	Community solar/battery storage	Utility-Scale	Generates and/or stores energy directly to grid (not direct to end users)
BTM Solar/Storage	Rooftop solar, home batteries	Residential/ Commercial	Generates and/or stores energy either directly to end users or via the grid
Virtual Power Plants (VPPs)	Software to aggregate connected technologies, automated demand response	Customer-Aggregated	Technology to aggregate and coordinate DERs

2.2 Summary of Benefits

In coordination with Solar United Neighbors (SUN), Current Energy Group (CEG) has identified and contextualized these benefits within Virginia's planning environment, recent utility resource decisions, and policy developments. Where possible, benefits are quantified using Virginia-specific data; where data is limited, assessments draw on industry benchmarks and best practices.

The distribution of these benefits is an important consideration. Some accrue to the electric system and all ratepayers, while others flow directly to participating customers or to society as a whole. To provide clarity and structure, this report organizes DERs benefits into three primary categories:

1. **System Benefits:** These are benefits that improve the performance and cost-efficiency of the electric grid. Examples include avoided generation, transmission, and distribution capacity costs, as well as avoided energy costs, reduced fuel price risk, and others.
2. **Participant Benefits:** These benefits accrue directly to customers who adopt DERs technologies. They include lower electricity bills, access to financial incentives, improved comfort and livability, resilience during outages, and empowerment through greater control and visibility of energy use.
3. **Societal Benefits:** These benefits extend beyond individual participants and utilities to the broader public. They encompass avoided greenhouse gas and air pollutant emissions, improved public health, brownfield development potential, workforce development, and economic growth from DERs investments.

Table 5. Summary of Benefits of DERs

Utility System Benefits		Participant Benefits	Societal Benefits
Avoided capacity costs (generation, transmission, and distribution)	Resource diversity and reduced fuel costs risks	Lower electricity bill & cost assistance	Avoided greenhouse gas & air pollution emissions
Avoided energy costs	Modular build & "right-sizing" investments	Increased comfort/ livability	Brownfield development potential
Ancillary Services (voltage and frequency regulation)	Rapid deployment capability	Resilience through disruption events	Reduced land footprint & aesthetics
System resilience (reduced outage risks)	Reduced planning risks ("just-in-time" investments)	Democratization and energy empowerment	Economic contributions (jobs, labor income, output, tax revenues)
Renewable integration (reduced curtailments)	State policy compliance	Access to data and enhanced control	Workforce readiness for the energy transition
	Leveraging private capital		

Together, these categories capture the comprehensive value proposition of DERs—demonstrating that their deployment not only addresses system needs but also advances affordability, equity, and sustainability goals for Virginia. Benefits vary in terms of their measurability across the following dimensions:

- **Monetizable benefits**, such as avoided energy and capacity costs.
- **Quantitative benefits**, such as reduced emissions.
- **Qualitative benefits**, such as customer empowerment and increased comfort.

2.3 System Benefits

Deploying DERs can enhance the electric system—the interconnected network of generation, transmission, and distribution that delivers power to customers—by providing electricity where and when it is needed. The contributions DERs make to support reliable and efficient system operations are known as grid services. By supplying these services, DERs can reduce or defer the need for traditional infrastructure investments—such as new poles, wires, transformers, or substation upgrades—while performing many of the same functions at potentially lower cost and with greater flexibility.

These benefits to the electric system ultimately translate into savings for both utilities and electric customers. Reduced system costs resulting from DERs-provided grid services lower utility expenditures and can contribute to lower electricity prices for consumers. Utilities track the costs of maintaining and operating the electric system, making the quantitative benefits of DERs to the system more straightforward to assess than benefits that accrue to individual customers (which might depend on rate design, as well as individual preferences and values).

Recent policy and technological developments have further expanded opportunities for customer-side resources to participate in wholesale electricity markets. Under Federal Energy Regulatory

Commission (FERC) Order No. 2222, DERs are permitted to participate directly in regional transmission organization and independent system operator markets alongside conventional generation.[9] This change enables additional value streams for customers and utilities through market revenues while also supporting grid reliability.

DERs can provide a wide range of grid services across all levels of the electric system. While studies have examined many potential services, practical valuation and compensation frameworks typically focus on a narrower subset of services with measurable and deployable benefits.[10] One example is New York's Value of Distributed Energy Resources (VDER) framework, which quantifies DERs compensation based on four core electric system benefits—energy, capacity, demand reduction, and locational system relief—as well as environmental benefits, which are addressed later in this report as societal benefits. [11]

Consistent with this approach, our framework evaluates a focused set of monetized grid services while also describing important non-monetized benefits delivered by DERs. Avoided cost projections are organized by the portion of the electric system they affect. These services fall broadly into two categories, energy and capacity, which correspond to the primary system costs that DERs help avoid. Capacity-related benefits are further disaggregated by generation, transmission, and distribution system impacts.[12, 13]

Energy and capacity provided by DERs benefit the electric system because they substitute for services the system would otherwise need to supply. Energy generated by distributed generation, such as solar, or avoided through energy efficiency reduces the amount of electricity that must be produced by utility-scale generators. This reduction lowers operational costs, including fuel, maintenance, and electrical losses associated with delivering energy to customers. Similarly, capacity contributions from DERs reduce the amount of generation, transmission, and distribution capacity required to meet peak demand, allowing utilities to defer or avoid investments in new lines, substations, and transformers. Other benefits to the system include operational benefits, like reduced operational risk through a diverse resource mix and leveraging private capital. Benefits to system planning include a mitigation of planning risks and supporting compliance with state policies.

[9] FERC, "Order No. 2222 Explainer: Facilitating Participation in Electricity Markets by Distributed Energy Resources" (September 25, 2025), https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy.

[10] See, for example, Patrick Balducci et al., "Assigning value to energy storage systems at multiple points in an electrical grid", *Energy & Environmental Science* 11 (June 4, 2018): 1926–44, https://doi.org/10.1039/C8EE00569A.

[11] New York State Energy Research and Development Authority (NYSERDA), "The Value Stack", https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources.

[12] Capacity is the ability to deliver energy at a given time. A simple analogy is a water pipe. Energy is analogous to the volume of water that flows, while capacity is the rate at which it can flow. A large volume of water can be delivered over a long time, from a small water pipe. However, if users demand a large volume of water at one time, then a much larger pipe, with higher capacity, is needed to provide adequate service.

[13] This category of capacity benefits for the distribution, transmission, and generation systems encompasses the same values quantified in NYSERDA's Value of DERs framework for Capacity, Demand Reduction, and Locational System Relief.

2.3.1 Avoided Capacity Costs

DERs deliver capacity benefits by lowering net electricity demand during peak demand periods. By reducing the maximum demand that must be supplied by generation, transmission, and distribution systems, less capacity is needed at each of these levels. Customers in Virginia can avoid costly investments in new infrastructure, including power plants, transmission lines, and distribution equipment by increasing DERs on the system.

Avoided capacity costs are calculated in terms of the annual cost savings per unit of firm capacity provided. Firm capacity refers to the portion of a resource's capacity that can be counted on to reliably meet peak demand. One common way to measure firm capacity is through the Effective Load Carrying Capability (ELCC), which quantifies the additional load a system can support with a given resource without reducing overall reliability. Every resource is subject to outages for maintenance, faults, or operating limitations that result in firm capacity contribution below the resource's nameplate capacity. Normalizing avoided capacity value in terms of firm capacity enables a consistent comparison across different resource types with different firm capacity percentages.

The avoided capacity value is also annualized because the costs of capacity are largely discrete capital investments during the resource's service life. Annualizing the total costs of the resource into a yearly cost in present-day dollars enables us to assess the value of deferring or eliminating the resource on an annual basis and compare that annual value directly to the annual costs of an alternative resource. To derive the annual expense from the initial capital costs, we calculate the annual carrying charge. The carrying charge calculation is an annual fixed payment calculation based on the asset life and utility cost of capital. We used Dominion's weighted average cost of capital (WACC) of 7.0%.[14]

Avoided Generation Capacity Costs

Generating capacity is provided by all generators that produce energy for the system. However, if additional capacity is required, the resource that utilities have historically procured was combustion turbine (CT) capacity. For example, Dominion recently filed for a certificate of convenience and necessity for the Chesterfield Energy Reliability Center (CERC), a 944 MW nameplate capacity natural gas CT generating facility.[15] In that sense, CTs represent the *marginal* resource that could be avoided by the deployment of DERs.

Our analysis of the avoided generation capacity value considers the cost of investing in a CT and maintaining its availability to generate electricity, if needed. The avoided generation capacity cost does not include the cost of generating. Thus, the avoided generation capacity cost includes initial capital expenses, fixed operation and maintenance (O&M), and firm transportation fuel supply costs.[16]

[14] Dominion last updated its WACC in its 2025 Rate Case; Dominion Energy, *Virginia Electric and Power Company Capital Structure and Cost of Capital Statement: Filing Schedule 3,* SCC, Case No. PUR-2025-00058 (March 31, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/84tc01!.PDF.
[15] Dominion Energy, *Virginia Electric and Power Company - For approval of a Certificates of Public Convenience and Necessity to construct/operate the proposed Chesterfield Energy and approval of designated Rider CERC,* SCC, Case No. PUR-2025-00037 (March 4, 2025), https://www.scc.virginia.gov/docketsearch#caseDetails/145916.
[16] Utilities contract for firm fuel transportation to enhance the reliability of the unit, ensuring that should its capacity be needed, the unit will have the fuel supply necessary to generate electricity. The firm transportation fuel supply costs do not include the price of natural gas.

The initial capital cost of constructing a new generator is the most significant component of the generation capacity cost. Recent market conditions have led to increased capital costs for new combustion turbines.[17] The analysis is informed by the capital costs filed in support of Dominion's request for approval of the CERC, $1,577/kW in 2025 dollars.[18] The annualized capital cost, using a 30-year useful life, is $137.13/kW-yr.

The total expense of a generation resource also includes costs to ensure that the resource remains available to operate at full capacity throughout the year and its useful life. For CTs, this requires a firm fuel supply to ensure that the unit is not de-rated during peak hours, particularly in winter, when gas supply might be constrained.[19]

For a CT, the National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline (ATB) moderate projections of fixed O&M are used for a 2028 in-service date, $28.98/kW-yr.[20] The firm fuel supply cost is estimated as $21.85/kW-yr, based on firm transportation rates for other utilities.[21,22] The generation capacity cost components are listed in Table 6.

Table 6. Avoided Generation Capacity Cost Components

Cost Component	Cost
Annualized Capital Cost ($/kW-yr)	$137.13
Fixed O&M ($/kW-yr)	$28.98
Firm Fuel Transportation ($/kW-yr)	$21.85

Generating capacity must account not only for serving customer load, but also for electrical losses and required planning reserves to reliably serve demand on the distribution system. DERs reduce demand at the distribution level, thereby offsetting generating capacity that would otherwise be required to serve both system losses and reserve obligations.

[17] Phil Besuner et al., "The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S." *GridLab, Energy Futures Group, and Halcyon,* (September 2025), https://gridlab.org/portfolio-item/gas-tubine-cost-report/.

[18] Unless otherwise indicated, all costs or values in this report are inflated to 2028 dollar years, using an inflation rate of 3%. The total cost of the CERC was $1,470 million in 2025 dollars, with a capacity of 944 MW. Direct Testimony of Jeffrey G. Miscikowksi, *Virginia SCC Case No. PUR-2025-00037* (March 3, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/845p01!.PDF.

[19] Recent major events have demonstrated that fuel supply constraints are a major contributor to CT outage rates. For example, MISO's review of winter storm Elliot in December 2022 highlighted the impact of "forced outages driven primarily by fuel supply issues." Midcontinent Independent System Operator (MISO), "Overview of Winter Storm Elliott December 23, Maximum Generation Event," *presented at the MISO Reliability Subcommittee*, (January 17, 2023), https://cdn.misoenergy.org/20230117.

[20] "2024 Electricity ATB Technologies and Data Overview," Annual Technology Baseline, National Laboratory of the Rockies, https://atb.nrel.gov/electricity/2024/index.

[21] Public Service Company of Colorado's 2024 Just Transition Solicitation published a firm fuel cost of $21/kW-yr for CTs. See, Colorado Public Utilities Commission *Docket No. 24A-0442E*.

[22] Louisville Gas and Electric's application for CPCN published a firm gas cost of $19/kW-yr. See, Kentucky Public Service Commission Docket No. 2025-00045.

In Virginia, approximately 6.25% of energy is lost as electricity travels through the transmission and distribution system.[23] As a result, serving 1 kW of load on the distribution system requires approximately 1.06 kW of generation. Consequently, a DERs that reduces load by 1 kW at the distribution level defers roughly 6% more capacity at the generation level.

Avoided generation capacity must also be adjusted to reflect planning reserve requirements. PJM maintains a reserve margin above expected peak load to ensure reliability during extreme weather events and unexpected unit outages. PJM's target reserve margin is 19.1% for the 2026 delivery year.[24]

In addition, avoided capacity costs must reflect the firm capacity contribution of the marginal generating resource. PJM calculates the ELCC of resources annually.[25] For a CT, PJM projects an ELCC of 61% for the 2027/2028 operating year, meaning only 61% of the CT's nameplate capacity is considered firm for reliability purposes.

The annual cost of firm generating capacity is calculated by summing the annualized capital carrying cost, fixed operations and maintenance costs, and firm fuel transportation costs. This total is then increased to account for electrical losses and reserve margin requirements. Finally, the adjusted cost is divided by the CT's ELCC to determine the cost of firm generating capacity required to serve 1 kW of load on the distribution system.

Using this methodology, the resulting value is $386.25 per kW-year, which represents the avoided generation capacity value of a 1 kW firm load reduction provided by DERs. The individual generation capacity cost adjustments and resulting firm capacity cost are summarized in Table 7.

Table 7. Avoided Generation Capacity Firm Cost

Capacity Cost Calculation	Value
Nameplate Capacity Cost ($/kW-yr)	$187.96
Electrical Loss Factor	6.25%
Reserve Margin	19.1%
ELCC	61%
Firm Generation Capacity Cost ($/kW-yr)	**$386.25**

Avoided Transmission Costs

Reducing net demand at the distribution level also reduces the need for transmission capacity to deliver energy from generation to distribution systems. The value of transmission capacity avoided by DERs was assessed using FERC Form 1 filings to estimate the cost of Dominion's transmission

[23] U.S. Energy Information Administration, "Virginia Electricity Profile 2024" (November 10, 2025), https://www.eia.gov/electricity/state/virginia/.
[24] Monitoring Analytics, LLC, "2025 Quarterly State of the Market Report for PJM: January through September", *Section 5: Capacity Market,* (November 13, 2025), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025q3-som-pjm-sec5.pdf.
[25] PJM, "ELCC Class Ratings for the 2027/2028 Base Residual Auction" (n.d.), https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf.

infrastructure. FERC Form 1 records a utility's total costs in a uniform system of accounts.[26] A subset of FERC accounts records the costs (net plant) of transmission infrastructure owned by the utility.[27] The total net distribution plant in these accounts was divided by Dominion's annual peak load to derive an embedded expense of distribution assets per kW of demand. This analysis was repeated for historical years 2019-2024 to produce an average expense. Dominion's average transmission infrastructure cost was $772.75 per kW.

The annual carrying charge calculation assumed a 50-year asset life for transmission infrastructure and Dominion's WACC. Additional costs were included for O&M, estimated at 3% of capital cost of transmission infrastructure annually, or $23.18.[28] Electrical losses were, again, assumed to be 6%.

The final deferred avoided transmission capacity value is $84.12 per kW per year. Table 8 lists each of the avoided transmission cost components.

Table 8. Avoided Transmission Capacity Cost Components

Capacity Cost Components	Cost
Transmission Annualized Capital Cost ($/kW-yr)	$55.99
O&M ($/kW-yr)	$23.18
Electrical Loss Factor	6.25%
Firm Transmission Capacity Cost ($/kW-yr)	**$84.12**

Avoided Distribution Costs

Evaluation of the avoided distribution capacity value follows a similar method to transmission using a subset of FERC accounts for distribution infrastructure owned by Dominion.[29] The total net distribution plant in these accounts was divided by Dominion's annual peak load. This analysis was repeated for historical years 2019-2024 to produce an average expense of $622.42 per kW.

The annual carrying charge calculation used a 50-year asset life for distribution infrastructure and Dominion's WACC. Distribution O&M was estimated at the same rate as transmission at 3% of capital expense annually, or $18.67. Electrical losses were, again, assumed to be 6%.

[26] Federal Energy Regulatory Commission, "Electric Industry Forms: Form No. 1 - Annual Report of Major Electric Utility" (n.d.), https://www.ferc.gov/general-information-0/electric-industry-forms.

[27] Specifically, our analysis included FERC accounts 352 - Structures and Improvements, 353 - Station Equipment, 354 - Towers and Fixtures, 355 - Poles and Fixtures, 356 - Overhead Conductors and Devices, 357 - Underground Conduit, and 358 - Underground Conductors and Devices as common transmission system elements that scale with customer demand. Code of Federal Regulations, Title 18, Chapter I, Subchapter C, Part 101: https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101.

[28] Midcontinent Independent System Operator, "Transmission Expansion Plan 2022, Transmission Cost Estimation Guide", (April 2022), Table 5.1, https://cdn.misoenergy.org/20220208%20PSC%20Item%2005c%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP22_Draft622733.pdf.

[29] Specifically, our analysis included FERC accounts 361 – Structures and Improvements, 362 – Station equipment, 364 – Poles, towers, and fixtures, 365 – overhead conductors, 366 – underground conduit, and 367 – underground conductors as common distribution system elements that scale with customer demand.

The final deferred distribution capacity value is $62.42 per kW per year. Table 9 lists each of the avoided distribution cost components.

Table 9. Avoided Distribution Capacity Cost Components

Capacity Cost Components	Cost
Distribution Annualized Capital Cost ($/kW-yr)	$40.07
O&M ($/kW-yr)	$18.67
Electrical Loss Factor	6.25%
Firm Generation Capacity Cost ($/kW-yr)	**$62.42**

2.3.2 Avoided Energy Cost

DERs avoid the costs of generating electricity by reducing energy consumption (such as energy efficiency), generating electricity on the distribution system (such as solar), or moving energy consumption from periods of high energy cost to periods of low cost (such as demand response or battery storage). This analysis is focused on DERs alternatives to generation needed to serve growing load, and the most likely sources of energy are gas combustion turbines and combined cycle gas turbines. In addition to direct costs of producing energy, gas-fueled generation also creates the societal cost of emissions generated as a byproduct. In this section, we considered the energy savings and generation from DERs that avoid the direct energy costs from both CTs as well as combined cycle (CC) natural gas units.

The cost of electricity from each generator includes fuel and variable O&M expenses. Fuel costs were estimated based on the heat rate for each unit, the amount of fuel needed to produce a unit of energy, and the price of fuel. Heat rates for combustion turbines and combine cycles were sourced from Dominion's 2024 IRP.[30] The fuel price came from the EIA Annual Energy Outlook 2025's forecast of natural gas delivered prices to the electric power sector, projected to be $3.57/MMBtu in 2028.[31] The heat rate and gas price result in a fuel cost per MWh of electricity produced of $40.92 for a CT, and $25.10 for a CC. NREL's 2024 ATB estimates the variable O&M for CTs at $7.81/MWh and for CCs at $2.76/MWh.[32]

The cost of energy must also be adjusted to account for electrical losses in delivering energy from the generator to the customers on the distribution system. We used the same loss factor of 6.25% to increase the cost of energy. Altogether, this results in a direct avoided cost of energy generation of $52.28/MWh for a CT and $29.77/MWh for a CC. The cost components for avoided energy cost for the CT and CC are compiled in Table 10.

[30] Combustion Turbine heat rate was taken as the average "CT Brownfield 4X" at 10.19 MMBtu/MWh and Combined Cycle heat rate was taken as average CC 2x1, at 6.25 MMBtu/MWh.; Dominion Energy, *Virginia Electric and Power Company's 2024 Integrated Resource Plan,* Virginia SCC Case No. PUR-2024-00184, Appendix 3B-5 "Average CT Brownfield 4X," (October 15, 2024), https://www.scc.virginia.gov/docketsearch/DOCS/820101!.PDF.
[31] Energy Information Administration, Annual Energy Outlook 2025, https://www.eia.gov/outlooks/aeo/.
[32] Variable O&M estimates were based on NREL ATB's moderate projections for a 2028 in-service data.

Table 10. Avoided Energy Cost

Cost Component	Technology Type	Cost ($/MWh)
Fuel	Combustion Cycle (CC)	$25.10
	Combustion Turbine (CT)	$40.92
Variable O&M	Combustion Cycle (CC)	$2.76
	Combustion Turbine (CT)	$7.81
Electrical Loss	Combustion Cycle (CC)	6.25%
	Combustion Turbine (CT)	6.25%
Total	Combustion Cycle (CC)	**$29.77**
	Combustion Turbine (CT)	**$52.28**

The cost of energy from a CC is less expensive than that from a CT. Therefore, CCs are typically operated more often to produce energy, while CTs operate only during peak demand hours. In determining the total energy costs of the fossil fueled portfolio, we used Dominion's average capacity factors (the fraction of time a unit is generating power) for its CTs and CCs to determine how much energy was delivered from each type of generation.[33]

2.3.3 Non-Monetized Benefits

DERs provide several grid services and other benefits to the electric system that are not as easily monetized as avoided costs for capacity and energy. Although our assessment of these benefits is qualitative, these benefits nonetheless represent genuine cost savings for utilities and customers.

Operational Benefits

The grid services provided by DERs have operational benefits that enhance flexibility, performance, and resilience of the electric system. When DERs are well integrated into electric utility operations, these services result in more reliable service for customers at lower cost.

Ancillary Services

Ancillary services are coordinated actions that maintain balance of the electric grid. The electric system is a constant balancing act to maintain the correct voltage and frequency, and adequate capacity.[34] Inverter-based resources (IBRs), including primarily solar and energy storage, can provide rapid responses to maintain this balance.

New IBRs are programmed to automatically adjust operation to support correct voltage and frequency in their area. These IBRs could further be actively managed and controlled to support system-wide stability needs. This contribution to grid balance can:

[33] For CTs, the projected capacity factor was averaged from Dominion's newest gas peaking plants (Ladysmith and Remington) for the years 2027-2029. For CCs, capacity factor was averaged for all gas baseload generators.; Dominion Energy 2024 IRP, Appendix 3B-4.

[34] In the electric grid, frequency is the speed at which the alternating current (AC) waveform oscillates, while voltage is the electrical pressure that drives power through transmission and distribution lines.

1) reduce the need for traditional voltage support infrastructure, like capacitor banks, that provide only that service, and
2) manage voltage throughout the distribution system to improve voltage optimization and conservation voltage reduction programs which contribute to additional energy and capacity savings.

DERs can also serve as operating reserves – resources that remain online, with the ability to increase or decrease generation within seconds to respond to changing system demand. For traditional fossil-fueled resources, like CTs, to provide operating reserves they must constantly run at reduced power levels. As quantified earlier in this report, the cost of generating electricity with CTs is much more expensive than baseload generators (or renewable generation), leading to increasing energy costs for providing operating reserves. Battery storage can quickly inject or absorb energy from the electric system, meaning it can provide operating reserves without incurring high energy generation costs.

Resilience

DERs materially enhance distribution system resilience by maintaining electric service during grid disruptions and reducing the scope and duration of outages. When faults occur on the distribution system, DERs can continue supplying power locally, limiting customer impacts even when portions of the grid are damaged or de-energized.

DERs provide resilience through multiple, complementary use cases. For example, a large energy storage system on the distribution system could enable sectionalizing and controlled islanding, allowing electrically isolated portions of the grid to remain energized when upstream facilities are compromised, such as when a primary feeder is taken out of service due to storm damage.

Behind-the-meter solar and battery storage offer an even more granular form of resilience by providing customers with on-site backup power when the surrounding grid is unavailable. These resources enable homes and businesses to sustain critical loads during outages, reducing reliance on emergency response, mitigating economic losses, and improving public safety—particularly during extreme weather and other high-impact events.

In addition, load reduction from DERs—including customer-sited solar, storage, and controllable load—facilitates faster distribution system reconfiguration during outages. By lowering demand on intact feeders, DERs reduce the risk of overloads when power is rerouted around damaged infrastructure, enabling utilities to restore service to a larger number of customers more quickly.

By keeping power on locally and reducing stress on the remaining grid during contingencies, DERs lower both customer outage costs and utility expenditures associated with hardening, reinforcing, or duplicating distribution infrastructure. In this way, investments in DERs—particularly behind-the-meter solar and storage—function as cost-effective resilience assets that complement traditional grid investments while delivering direct reliability benefits to customers.

Renewable Integration

The increasing level of renewable generation can lead to novel issues for the electric system, such as constrained capacity for moving renewable energy from the generators to other customers, and rapid changes in net load as renewable generation increases or decreases. Demand response and energy storage resources can reduce these system impacts from renewable energy by shifting net load and counteracting changes in generation.

For example, during periods of high renewable generation, energy storage resources can charge from the grid, to utilize the energy that might otherwise overload the electric system or lead to curtailment of those renewable resources.

As another example, demand response could counteract a sudden decrease in solar generation (e.g., due to cloud cover) by triggering a setback of thermostats for 15 minutes while other resources ramp up to meet the growing net load due to the reduced solar generation. These renewable integration benefits avoid other utility investments to meet these challenges, such as additional operating reserves, or increased distribution and transmission capacity, saving customers money while facilitating the continued transition to clean electricity sources.

Resource Diversity and Reduced Fuel Costs Risk Reduction

Incorporating DERs into the electric system creates resource diversity and limits dependence on fossil fuels which can reduce operational risks for the electric system. Alternatively, continuing to build and operate the electric system dependent on central fossil-fueled generation, in an era of rapidly changing technology, prices, and policies creates operational risks for utilities.

In recent years, fuel supply issues have highlighted reliability concerns for electric systems largely dependent on gas-fired generation. This risk is particularly acute during the winter, when electricity generation competes with heating needs for access to limited gas capacity. In December 2022, Winter Storm Elliott produced record peak demand conditions in PJM while gas supply disruptions forced outages at gas-fired units, resulting in 23% of gas-fired capacity within PJM being unavailable.[35]

In 2023, Virginia's electric system generated more than half its energy from gas and approximately 12% from renewables.[36] Continuing to add gas-fired resources increases the risk of widespread outages, while diversifying the resource mix reduces fuel supply and forced outage risks.

Fuel outages are not the only operational risk to gas resources. Gas prices have fluctuated up to 500% in the past five years,[37] which are costs that are passed on to customers through fuel and purchased power adjustment riders. Fuel costs contribute 80% to 90% of the direct costs of energy generation.[38] Virginia generated over 6.5 million MWh of electricity from gas in 2023.[39] A doubling of the cost of gas (which we calculated to be $25.10/MWh for a new CC generator) would result in a $163 million increase in electricity bills in VA. In contrast, renewable distributed generation resources have only fixed costs, providing relative price stability for electric customers.

[35] PJM, "Winter Storm Elliott Event Analysis and Recommendation Report" (July 17, 2023), Figures 38 and 39, https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[36] U.S. Energy Information Administration, "Virginia State Profile and Energy Estimates", https://www.eia.gov/state/?sid=VA.

[37] U.S. Energy Information Administration, "Henry Hub Natural Gas Spot Price", https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

[38] See Section 2.3.2 on Avoided Energy Cost.

[39] U.S. Energy Information Administration, "Virginia State Profile and Energy Estimates", https://www.eia.gov/state/?sid=VA.

Leveraging Private Capital

DERs offer utilities an opportunity to leverage a separate, non-traditional form of financing from private capital investments. Unlike traditional utility-owned infrastructure, many DERs are financed directly by participants—such as households, small businesses, and third-party providers—rather than by the utility itself.

In addition, large energy users can deploy private capital to fund DERs installations that serve both their own needs and the broader grid, as demonstrated by large-load examples such as data center–backed clean energy and grid-support investments. For example, Google has committed to funding energy efficiency programs in Nebraska,[40] Texas,[41] and Arkansas.[42]

Harnessing private capital through deployment of DERs directly lowers the utility revenue requirement. When DERs displace utility-owned assets, ratepayers avoid paying the utility's weighted average cost of capital, including both debt and equity financing costs, currently estimated to be 7%.[43] This approach optimizes the use of ratepayer funds by targeting utility investments, while also allowing private actors to fund assets that can meet system needs more efficiently.

Beyond cost savings, leveraging private capital also reduces financial and operational risk for ratepayers. Third-party developers and participants assume performance, technology, and market risks associated with DERs investments, rather than shifting those risks onto customers through regulated rates. In this way, DERs substitute private capital for utility capital in a manner that lowers financing risks for the utility.

Planning Benefits

As a "right-sized" approach that can be rapidly scaled based on needs, DERs offer distinct planning benefits compared to traditional fossil fuel or wired alternative resource options.

Modular Build & Reduced Planning Risks

Energy storage, renewable energy, and demand-side management (DSM) strategies are increasingly recognized as low- or no-regrets options in utility planning. These resources retain their value across a wide range of future scenarios, including those involving slower load growth, changing regulatory environments, or evolving market dynamics. Unlike conventional thermal resources, they are less exposed to policy risks. Similarly, unlike capital-intensive, long-lead-time, large-scale resources, they do not introduce overbuilding risk to the system.

Modular, scalable resources offer inherent planning flexibility, allowing utilities to take a more adaptive, incremental approach to capacity investment. This flexibility helps reduce the risk of

[40] Lincoln Electric System, "LES receives funding from Google to scale energy-efficiency projects for affordable housing", (September 9, 2025), https://www.les.com/company/news/les-receives-funding-google-scale-energy-efficiency-projects-affordable-housing.
[41] Google, "Google commits to increasing energy abundance and reliability for Texans", (November 14, 2025), https://datacenters.google/google-commits-to-increasing-energy-abundance-and-reliability-for-texans/.
[42] Google, "Google is investing in Arkansas with a new data center, energy efficiency programs and more", (October 2, 2025), https://blog.google/inside-google/company-announcements/google-american-innovation-arkansas/.
[43] Dominion last updated its WACC in its 2025 Rate Case: Dominion Energy, *Virginia Electric and Power Company Capital Structure and Cost of Capital Statement: Filing Schedule 3*, (March 31, 2025), SCC Case No. PUR-2025-00058.

overbuilding and avoids the financial burden of stranded assets, challenges that are especially pronounced with centralized gas-fired plants, which require significant upfront capital, have long development timelines, and face growing risks of underutilization in futures with flat load growth or tighter carbon constraints. In contrast, renewable energy, energy storage, and DSM can be deployed incrementally and continue to improve operational efficiency even during periods of lower demand—rather than sitting idle, as a CT would. Demand-side resources can also be scaled back if needs change, without leaving ratepayers responsible for long-term capital recovery. Some DSM programs, including VPPs, feature performance-based compensation that protects other customers if those resources underperform, unlike traditional fossil assets, where capital costs remain sunk regardless of performance.[44]

In addition, although current federal policies do not restrict investments in new gas-fired generation, this status is unlikely to persist indefinitely. Future carbon regulations, whether through direct pricing mechanisms, emissions caps, or operational constraints, could significantly erode the cost-effectiveness of fossil-based assets. In contrast, investments in clean energy portfolios are inherently future proof in this regard, insulating utilities and ratepayers from the uncertainty of evolving environmental policy.

Rapid Deployment

The US grid is facing a period of unprecedented load growth projections, creating an urgent need to deploy all available resources as fast as possible. As a result, priorities in resource planning have shifted from a focus on relative economics to considerations like deployment timelines and other execution concerns. This urgency, however, can lead to investments in resources that might appear valuable in the near-term, but pose a risk of overburdening ratepayers with high long-term costs. The challenge is further compounded by heightened concerns around reliability, especially during extreme weather events, leading utilities, regulators, and consumers to look for short-term solutions.

The sudden growth in demand for gas-fired capacity, combined with a lack of skilled labor and facilities to quickly ramp up production, has led to a growing backlog in gas turbine orders.[45] This backlog is not only leading to increased costs but also longer delivery timelines. In contrast, renewable energy, energy storage, and especially, demand-side resources can be deployed on significantly faster timelines.

- Rooftop and small-scale solar and storage systems (behind-the-meter) are usually operational in one year with residential rooftop projects usually complete in less than six months.
- Larger solar resources (including front-of-meter solar) can typically be brought online within three to five years.

[44] For example, see Public Service Company of Colorado's proposed ADPP tariff that is based on actual delivery during events: Public Service Company of Colorado, *Aggregator Virtual Power Plant Program*, Hearing Exhibit 102, Attachment ZDP-1, Colorado Public Utilities Commission, Proceeding No. 25A-0061E, (January 21, 2025), p. 12, https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=103492
[45] Diana DiGangi, "Gas turbine manufacturers expand capacity, but order backlog could prove stubborn", Utility Dive (September 5, 2025), https://www.utilitydive.com/news/mitsubishi-gas-turbine-manufacturing-capacity-expansion-supply-demand/759371/.

  - PacifiCorp's 2025 IRP studies identify a total implementation timeline of approximately three years for utility scale solar and small-scale wind projects.[46]
  - Duke Energy Carolinas and Duke Energy Progress assume that solar to be selected in the 2025 IRP can achieve commercial operations by 2030.[47]
  - In their 2024 IRP, Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU) identify 2028 as the earliest in-service year for both solar and wind resources.[48]
- Energy storage resources, including long-duration options, have construction timelines of one to three years.
  - A 200 MW carbon dioxide-based energy storage project in Columbia County, Wisconsin, is expected to begin construction in 2026 and be completed by 2027.[49]
  - PacifiCorp 2025 IRP studies identify a total implementation timeline of one to three years for four-hour batteries and two to three years for 12- and 100- hour energy storage options.[50]
  - Duke Energy Carolinas and Duke Energy Progress assume that storage resources selected in the 2025 IRP can achieve commercial operations by 2028.[51]
  - In their 2024 IRP, LG&E/KU identify 2028 as the earliest in-service year for four-hour and eight-hour batteries.[52]
- EE and DR resources can be procured and deployed on significantly shorter timelines.
  - A VPP in Ontario enrolled 100,000 homes for a total of 90 MW of participating resources within six months.[53]
  - In their 2024 IRP, LG&E/KU identify 2027 as the earliest in-service year for "Bring your own Device" resources (in contrast with gas fired resources which have an earliest in-service year of 2030).[54]
- Demand-side resources are also not subject to the same execution risks as traditional generation, such as supply chain constraints, labor shortages, or interconnection delays.

[46] PacifiCorp, 2025 Integrated Resource Plan, "Public Supply-Side Resource Data Summary-2025", (March 31, 2025), https://www.pacificorp.com/energy/integrated-resource-plan/support.html.
[47] Duke Energy, "Chapter 2: Methodology and Key Assumptions," in *2025 Carolinas Resource Plan* (October 1, 2025), https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/2025/02-chapter-2-methodology-key-assumptions-web.pdf.
[48] Louisville Gas and Electric Company and Kentucky Utilities Company, *2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company: Volume III*, Case No. 2024-00326 (Kentucky Public Service Commission, October 18, 2024), https://psc.ky.gov/pscecf/2024-00326/rick.lovekamp%40lge-ku.com/10182024014139/08-LGE_KU_2024_IRP_Volume_III.pdf.
[49] Public Service Commission of Wisconsin, *Joint Application of Wisconsin Power and Light Company, Wisconsin Public Service Corporation, and Madison Gas and Electric Company - Final Order,* Public Service Docket No. 5-CE-156, (June 30, 2025), https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=552008.
[50] PacifiCorp, 2025 Integrated Resource Plan.
[51] Duke Energy, 2025 Carolinas Resource Plan, Chapter 2.
[52] LG&E/KU, 2024 Joint IRP Volume III, Table 3.
[53] Emma Penrod, "How an Ontario Virtual Power Plant Enrolled 100,000 Homes in Just Six Months," *Utility Dive* (February 5, 2024), https://www.utilitydive.com/news/ontario-vpp-virtual-power-plant-energyhub/706496/.
[54] LG&E/KU, 2024 Joint IRP Volume III, Table 3, Table 1.

- The shorter construction timelines associated with DERs, combined with the ability to leverage surplus interconnection capacity for renewable energy and energy storage, can significantly accelerate the deployment of new capacity—well before new gas-fired units are able to reach commercial operation.

State Policy Compliance

The VCEA requires Dominion and Appalachian Power ("APCo") to participate in a renewable energy portfolio standard program (RPS Program) that establishes annual goals for the sale of renewable energy to all retail customers in the utility's service territory.[55] The RPS Program requirements shall be a percentage of the total electric energy sold in the previous calendar year – in 2025 they were 14% for APCo and 25% for Dominion.

DERs can play a critical role in helping Virginia meet its RPS Program mandates. As generating resources, technologies such as distributed solar directly contribute to RPS compliance by producing renewable energy and associated Renewable Energy Certificates (RECs). These certificates represent proof of one megawatt-hour (MWh) of renewable generation and are essential for utilities to demonstrate compliance with statutory targets.

If a Phase I or Phase II utility does not meet its annual RPS requirements, or if the cost of the RECs needed for compliance rises above $45 per MWh, the utility must make a deficiency payment. The payment is set at $45 for each MW of the shortfall for that year. However, for shortfalls related to solar, wind, or anaerobic digester projects located in Virginia and sized at 1 MW or smaller, the deficiency payment increases to $75 per MWh (Table 11). These values represent the effective shadow price for RECs (i.e., the effective price of compliance created by a policy constraint, even when no explicit market price exists).

Table 11. REC Deficiency Payment Levels

RPS Deficiency Payments	Cost
Generic	$45
Small-scale RPS Carve Out (<1 MW)	$75

In addition to supporting compliance with the VCEA, distributed energy resources also advance compliance with the Virginia Environmental Justice Act (VEJA) by enabling more targeted and equitable deployment of clean energy investments.[56] Passed in 2020, VEJA requires state agencies and regulated entities to consider and mitigate disproportionate environmental and health impacts on historically marginalized and overburdened communities.

DERs—particularly distributed solar, storage, energy efficiency, and demand response—can be intentionally sited and designed to deliver localized benefits, including reduced energy burdens, improved resilience, and avoided exposure to pollution associated with centralized fossil generation. By facilitating clean energy deployment at the community level, DERs provide utilities with a flexible compliance pathway that aligns renewable energy procurement with statutory environmental justice objectives, while reducing the risk that infrastructure investments exacerbate existing inequities.

[55] Code of Virginia § 56-585.5.C.

[56] Code of Virginia, Title 2.2, Article 12. Virginia Environmental Justice Act.

2.4 Participant Benefits

Beyond their contributions to the electric system, DERs deliver tangible and meaningful benefits to participating customers. These benefits extend across financial, comfort, resilience, and empowerment dimensions, creating a compelling value proposition for households, businesses, and communities that choose to adopt DERs technologies.

Lower Energy Costs and Financial Incentives

Participation in DERs programs can reduce electricity bills for customers through on-site generation, energy efficiency measures, and demand response programs. Customers who install rooftop solar or pair solar with battery storage can offset a substantial portion of their energy consumption, while energy efficiency upgrades reduce overall usage. Through net energy metering, customers that generate electricity (such as with a rooftop solar system) are credited for the electricity they generate against the electricity they consume on their bill. The credits from net energy metering can even offset the entire electric bill if they generate more energy than they consume. With net metering, rooftop solar systems can pay for themselves in under ten years and continue to reduce electricity bills for up to thirty years.[57]

In addition to bill savings, participants often receive upfront incentives, rebates, or appliance cost assistance. Incentives vary by utility, program, and DERs type. As examples of incentive levels, Dominion has specified the following as part of their VPP Pilot filing:[58]

- **Residential Battery Storage Pilot:** One-time enrollment incentive of $1,000 plus an annual incentive of $294 for discharging batteries during grid events.
- **Residential Smart Thermostat:** $75 enrollment incentive and $40 annual incentive.
- **Residential EV Managed Charging:** $40 enrollment incentive and $10 monthly incentive (or $20 enrollment and $5 monthly for TOU customers).
- **Income and Age Qualifying Battery Storage Pilot:** Free battery installation (approx. $20,000 value) plus ongoing performance incentives.
- **Peak Time Rebate:** Up to $28 per customer annually for event participation.

On-bill financing or "pay-as-you-save" (PAYS) programs are additional tools for lowering financial and adoption barriers for DERs because they allow participants to pay for the installation over time through their utility bill, eliminating or greatly reducing the need for large initial expenditures.[59] Payments are often structured so that the monthly repayment is equal to or less than the energy cost savings generated by the DERs. This means participants can implement DERs without increasing overall household energy spending, making adoption feasible for low- and moderate-income customers.

[57] U.S. Department of Energy, "End-of-Life Management for Solar Photovoltaics", https://www.energy.gov/eere/solar/end-life-management-solar-photovoltaics.
[58] Direct Testimony of Courtney S. Young, *Virginia SCC Case No. PUR-2025-00211*, (December 1, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/89hz01!.PDF.
[59] Examples of on-bill financing programs include Michigan Saves/Traverse City Light & Power (Michigan), National Grid (Massachusetts & Rhode Island), Help My House (South Carolina), and Midwest Energy's How$mart (Kansas).

Enhanced Comfort and Livability

Energy efficiency measures—such as HVAC upgrades, smart thermostats, and weatherization (e.g., insulation, air sealing, new windows)—significantly improve indoor comfort by maintaining consistent, comfortable temperatures and eliminating drafts.

Crucially, these upgrades do much more than save money; they are a direct investment in the health and productivity of the occupants through:

- **Thermal Comfort:** When a home is reliably comfortable, occupants are better positioned to live their lives fully. Consistent, healthy temperatures mean children can focus better on schoolwork; adults can work remotely or rest more effectively; and the elderly or those with health conditions can safely reside in their homes regardless of the outside weather extremes. The elimination of thermal stress transforms the home into a sanctuary that supports overall well-being, rather than a source of discomfort or anxiety.
- **Improved Indoor Air Quality:** Modern, properly sized HVAC systems, especially those with advanced filters, can dramatically reduce indoor pollutants like dust, allergens, pet dander, and mold spores. Furthermore, sealing a home (weatherization) and installing modern, sealed-combustion heating systems and balanced ventilation systems prevent harmful combustion gases (like carbon monoxide) and moisture buildup (which causes mold) from affecting occupants.
- **Reduced Health Risks:** By improving thermal comfort, these measures reduce health risks associated with extreme temperatures. Eliminating dangerously cold or hot spots helps prevent respiratory symptoms, asthma exacerbations, and even fatal conditions like hypothermia or cardiovascular stress during heat waves.
- **Reduced Noise:** Upgrading from older, inefficient equipment to modern, high-efficiency models significantly reduces noise pollution both inside and outside the home.

Resilience During Disruptions

Behind-the-meter storage and solar-plus-storage systems provide backup power during outages, enabling homes and businesses to maintain essential services when the grid is down. This resilience is particularly valuable during extreme weather events or other disruptions, reducing vulnerability and increasing peace of mind for participants.

While a loss of power is inconvenient for most, it can be life-threatening for specific, often vulnerable, populations. The benefits of backup power are disproportionately high for these groups:

- **Medically Fragile Individuals**: People who rely on electricity-dependent durable medical equipment—such as ventilators, oxygen concentrators, or electric wheelchairs—face immediate and acute danger when power is lost. Backup batteries in these devices often last only a few hours, a threshold that is frequently surpassed during major, storm-related outages.
- **The Elderly and Chronically Ill**: Without power, air conditioning, heat, and refrigeration are lost. This can lead to hyperthermia (heat stroke) or hypothermia when the home's temperature cannot be regulated, especially for older adults or those with cardiovascular

and respiratory conditions.[60] Medications requiring refrigeration also become compromised due to outages or appliance failures during extreme conditions. Many older adults rely on others for medical care and assistance with daily activities, which further increases their vulnerability during outages.

- **Children and Youth:** Young bodies are less able to regulate temperature extremes, making them vulnerable during outages that eliminate heating or cooling.[61] Extended exposure to heat or cold can lead to serious health risks such as dehydration, heat exhaustion, or hypothermia. Additionally, disruptions can endanger pregnant and postpartum individuals and their infants, as loss of refrigeration compromises breastmilk and medications. Unsafe sleeping arrangements during cold conditions may also increase the risk of sudden infant death syndrome.[62]
- **Low-Income Households**: Studies show that socioeconomically disadvantaged communities often experience more frequent and longer-duration power outages due to older infrastructure and potential biases in utility restoration protocols.[63] Furthermore, they are less likely to have the financial resources to evacuate, replace spoiled food, or purchase expensive, temporary solutions like gas-powered generators (which themselves carry the risk of deadly carbon monoxide poisoning if used improperly).

Democratization and Energy Empowerment

DERs transform customers from passive consumers into active participants in the energy ecosystem. By generating their own electricity or contributing flexible load through demand response, participants gain energy independence and self-sufficiency. The democratization of energy resources fosters community engagement and supports broader equity goals. The shift from centralized to decentralized moves the power system closer to the users, giving them direct control over their energy supply and promoting a more resilient, distributed, and user-centric grid.

This drive for energy independence and self-consumption is a powerful motivator for many DERs adopters. For these individuals and communities, owning the means of energy production—such as rooftop solar panels paired with battery storage—is valued not just for the potential cost savings but for the ability to:

- Insulate themselves from utility rate fluctuations.
- Maintain power during centralized utility grid outages (increasing resilience and ability to support nearby community members).
- Decouple from a centralized utility system, which can be particularly appealing in regions with perceived reliability issues or excessive costs.

[60] National Integrated Heat Health Information System, “At Risk: Older Adults”, https://heat.gov/who-is-most-at-risk-to-extreme-heat/at-risk-older-adults/.
[61] American Academy of Pediatrics, “Extreme Temperatures: Disaster Management Resources” (October 25, 2024), https://www.aap.org/en/patient-care/disasters-and-children/disaster-management-resources-by-topic/extreme-temperatures/?srsltid=AfmBOooKz3TIG7NG9N_CpimcrNLr2MC-eCMYBwHqjOobyMT23674Qjfm
[62] National Institutes of Health, “Avoid SIDS During Cold Weather” (December 2010), https://newsinhealth.nih.gov/2010/12/avoid-sids-during-cold-weather
[63] Scott C. Ganz, Chenghao Duan, and Chuanyi Ji. "Socioeconomic vulnerability and differential impact of severe weather-induced power outages." *PNAS nexus* 2, no. 10 (2023), https://doi.org/10.1093/pnasnexus/pgad295.

Access to Data and Enhanced Control

Modern DERs technologies often include advanced monitoring and control features, giving participants real-time insights into their energy usage and system performance. Access to this data empowers customers to make informed decisions, optimize consumption, and further reduce costs. Access to detailed energy use data empowers residential customers to transform their energy behavior and make informed, active decisions. Through behavioral optimization customers can see exactly when and where energy is being consumed (e.g., HVAC vs. appliances), which allows customers to schedule large energy uses or make immediate adjustments to consumption patterns.

For commercial and industrial (C&I) customers, the data and control capabilities offer critical support for business objectives:

- **Sustainability Reporting:** Detailed, verified consumption and generation data directly supports mandatory or voluntary Environmental, Social, and Governance reporting and compliance with carbon-reduction targets. This verifiable data enhances corporate credibility and adherence to sustainability goals.
- **Operational Efficiency:** C&I facilities use data to identify and manage the largest drivers of energy cost, particularly demand charges (fees based on the single highest moment of energy consumption). Automated controls can preemptively curtail non-essential loads or discharge a battery to "shave" this peak, which directly reduces operating expenses.
- **Integration with Building Management Systems**: Advanced DERs control platforms seamlessly integrate with existing building management systems, allowing facilities managers to view energy assets (like solar and storage) and traditional assets (like chillers and lighting) through a single dashboard for holistic energy management. This additional information empowers users and helps identify potential cost-saving sources.

This sophisticated level of monitoring and control fundamentally changes the relationship between the customer and their energy use, moving it from passive billing to active, continuous optimization.

2.5 Societal Benefits

Societal benefits represent the benefit types that accrue broadly regardless of if people are customers of the utility or themselves participate directly in a DERs program.

Avoided GHG & Air Pollution Emissions

Utilizing DERs in place of traditional generation reduces reliance on fossil fuels, thereby avoiding associated emissions and mitigating environmental and public health impacts from air pollutants. The social cost of carbon represents the monetized value of societal damages for each metric ton of CO_2 emitted and is currently estimated at approximately $95.52.[64] The U.S. Environmental Protection Agency's CO-Benefits Risk Assessment (COBRA) tool quantifies the economic value of avoided air pollutants, including particulate matter (PM), sulfur dioxide (SO_2), and nitrogen dioxide (NO_2).[65] Considering the two primary types of generators responsible for these emissions—

[64] Rennert, K., Errickson, F., Prest, B.C. *et al.* "Comprehensive evidence implies a higher social cost of CO_2", *Nature* 610, 687–692 (2022). https://doi.org/10.1038/s41586-022-05224-9

[65] U.S. Environmental Protection Agency, "CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA)", https://www.epa.gov/cobra.

combustion turbines and combined-cycle units—a per-unit cost has been calculated for avoided carbon (CO_2) and air pollutants. To understand the magnitude of potential avoided costs associated with fossil fuel generation, the annual social cost associated with emissions from a 500 MW nameplate CC and 500 MW CT fossil-fueled portfolio (1000 MW total) are presented in Table 12.[66]

Table 12. Societal Benefits of Avoided GHG and Air Pollution by Generator Type

Emission Type	Technology Type	Societal Cost ($/MWh)	1000-MW Fossil Fuel Portfolio Cost ($ per year)
CO_2	Combustion Cycle (CC)	$31.59	$116 million
	Combustion Turbine (CT)	$51.50	$12 million
Air pollution (Nox, PM2.5, SO2)	Combustion Cycle (CC)	$14.74	$54 million
	Combustion Turbine (CT)	$33.74	$8 million
Total	Combustion Cycle (CC)	**$49.22**	**$190 million**
	Combustion Turbine (CT)	**$90.57**	

Brownfield and Disturbed Land Development Potential

Distributed resources have the potential to be deployed on disturbed lands, such as parking lots, brownfields, landfills, as well as in coordination with agricultural development (i.e., agrivoltaics). The opportunities for disturbed land deployment are particularly suitable for larger-scale, FOM solar and battery storage projects, such as community solar and storage. Locating energy resources on disturbed lands, whether they be utility-scale or small-scale, reduces land-use conflicts and accelerates project timelines compared to greenfield sites by leveraging areas that are already developed, but underutilized because they are unsuitable for other applications. The small scale and flexible interconnection of DERs enable their deployment on disturbed lands, allowing for efficient use of space while avoiding the constraints associated with larger energy projects.

Virginia has statewide brownfield redevelopment priorities, including a policy "to encourage remediation and restoration of brownfields by removing barriers and providing incentives and assistance whenever possible."[67] Locating DERs—such as FOM community solar and battery storage—on brownfields and other disturbed lands offers dual benefits: it accelerates renewable deployment while revitalizing underutilized properties.

Virginia's "Brownfields Restoration and Economic Redevelopment Assistance Fund" provides grants for site assessments and remediation that could be used for distributed generation projects.[68] By prioritizing these sites, DERs development avoids greenfield conversion, reduces permitting complexity, and aligns with state economic development goals. This approach also mitigates environmental liabilities, turning previously blighted areas into productive assets that generate clean energy and local tax revenue.

[66] See Appendix B. Modeling Assumptions (Fossil Fuel Resource Assumptions) for capacity factor assumptions.
[67] Code of Virginia § 10.1-1231 The Virginia Brownfields Restoration and Renewal Land Renewal Act.
[68] More information about Virginia's brownfields, including grants for site assessments, planning, and remediation through the Virginia Brownfields Restoration and Economic Redevelopment Assistance Fund, are available at: https://www.deq.virginia.gov/land-waste/remediation-programs/brownfields.

Reduced Land Footprint & Aesthetics

Distributed resources require less land than centralized generation. This smaller footprint preserves open space, agricultural land, and culturally significant landscapes, reducing conflicts over land use. Additionally, DERs can be integrated into existing built structures (e.g., rooftops, parking lots), minimizing visual impacts and maintaining community aesthetics. These siting advantages help maintain Virginia's rural character and heritage while enabling clean energy growth.

Reducing land impacts from energy infrastructure can help protect cultural, spiritual, and aesthetic values that are especially significant to Tribal Nations, which have historically experienced disproportionate and adverse impacts from such development. For example, members of the Nansemond Indian Nation have recently voiced concerns about the proposed Virginia Reliability Project pipeline expansion by TC Energy, which would cross the Nansemond River and the northern boundary of the Great Dismal Swamp.[69] These areas are considered vital cultural and spiritual places of refuge, and the tribe is concerned about the impact on centuries-old natural and cultural resources. Avoiding, minimizing, or deferring infrastructure investments through DERs reduces the risk to these non-monetized, yet highly significant, societal considerations.

Economic Contributions to Jobs, Labor Income, Economic Output, and Tax Revenues

Investments in DERs support employment and economic activity across multiple segments of Virginia's economy. Unlike large, centralized generation projects, DERs deployment is more labor-intensive and locally anchored, driving demand for electricians, HVAC technicians, energy auditors, engineers, software and data specialists, project managers, and ongoing operations and maintenance staff. These investments also generate indirect and induced economic effects through supply chains and increased household spending, contributing to labor income and statewide economic output.

The Clean Energy Policy states that it is Virginia's policy to maximize energy efficiency programs "in order to produce electricity cost savings and to create jobs and economic opportunity from the energy efficiency sector."[70] This objective recognizes that DERs investments create near-term construction and installation jobs while also supporting longer-term employment in program administration, system operations, customer engagement, and performance monitoring.

In 2020, Virginia Commonwealth University's Center for Urban and Regional Analysis analyzed the economic impact of deploying 2,500 MW of distributed solar capacity in the state.[71] Their findings indicated that achieving this level of solar build-out could generate more than 29,000 job-years of direct employment over the construction period—equivalent to roughly 2,900 sustained jobs per year if the installations were spread across a decade. These investments would create total economic output of $7.1 billion and would generate over $860 million in federal, state, and local tax revenues in Virginia.

[69] Katherine Hafner, "Nansemond Indian Nation, environmental groups concerned by pipeline project in Hampton Roads", *WHRO Public Media* (March 29, 2023), https://www.whro.org/2023-03-29/nansemond-indian-nation-environmental-groups-concerned-by-pipeline-project-in-hampton-roads.

[70] Code of Virginia § 45.2-1706.1.A.5.

[71] Virginia Commonwealth University, Center for Urban and Regional Analysis, "Assessing the Benefits of Distributed Solar in Virginia" (April 2020), https://cura.vcu.edu/media/cura/pdfs/cura-documents/CURAdistributedsolarreportv.1.2.withupdatedcurrentemployment.pdf.

Workforce Readiness for the Energy Transition

Virgina state policies like the VCEA recognize that the Commonwealth is amid a clean energy transition away from fossil fuels and towards non-emitting energy resources. The Commonwealth's Clean Energy Policy both acknowledges this transformation as well as the need to ready the economy and workforce in an equitable fashion: [72]

> "As Virginia transforms its energy economy, the Commonwealth must continue to prioritize economic competitiveness and workforce development in an equitable manner."

Shifting from traditional fossil fuels resources to clean energy requires technologically sophisticated and diverse resources, along with a skilled, widely distributed workforce and participation from businesses of all sizes. Virginia has developed two critical tools to help smooth the transition.

The first is that Virginia Energy—the state agency charged with advancing Virginia's energy, mining, and mineral policies and initiatives—has created "Clean Energy Workforce Programs" that equip energy workforce professionals with the skills necessary to support clean energy projects.[73] Through partnerships with educational institutions and employers, the programs provide workforce training and financial assistance. Jobs in clean energy are generally higher paying than regional averages. For example, electrical and electronics installers and repairers earn an average of $71,270 per year,[74] higher than the Virginia median annual income (statewide including both rural and urban areas) of $53,020.[75] Solar photovoltaic installers are close to the state median at $51,860; the industry is poised for significant growth of 42% from 2024 to 2034, much faster than the average for all occupations.[76]

Virginia's second tactic to position the state for the energy future is to ensure that the clean energy workforce and businesses have sufficient stability for the nascent industry to more quickly achieve commercial viability. Virgina has helped stabilize demand through the VCEA by setting minimum requirements for energy efficiency, creating the Virtual Power Plant Pilot, and establishing interim achievements for many clean energy technologies, including some distributed resources.[77] By ensuring a predictable market, Virginia reduces investment risk, supports workforce continuity, and enables clean energy businesses to scale more efficiently as technologies mature.

As the grid becomes more distributed, digital, and customer-integrated, the value of adaptable, cross-disciplinary skill sets increases, and DERs programs provide a practical on-ramp for workers to gain experience with these emerging systems. In this way, investments in DERs helps align workforce capabilities with long-term decarbonization, resilience, and electrification goals, ensuring that workers are prepared for future roles even as job categories and functions continue to shift.

[72] Virginia Code § 45.2-1706.1.C.
[73] More information about Virginia Energy's Clean Energy Workforce Program is available at: https://energy.virginia.gov/Energy/CEWP.shtml.
[74] U.S. Bureau of Labor Statistics, "Installation, Maintenance, and Repair Occupations", https://www.bls.gov/ooh/installation-maintenance-and-repair/home.htm.
[75] Virginia Department of Workforce Development and Advancement, "Virginia Occupational Employment and Wage Statistics 2024" (May 21, 2025), https://virginiaworks.gov/virginia-occupational-employment-and-wage.
[76] U.S. Bureau of Labor Statistics, "Solar Photovoltaic Installers", https://www.bls.gov/ooh/construction-and-extraction/solar-photovoltaic-installers.htm.
[77] See Section 3.2 for a further discussion of near-term requirements for DERs under VCEA and the Virtual Power Plant Pilot as defined by the Community Energy Act.

3 Cost-Effectiveness of DERs

This section moves beyond the overview of the benefits of DERs by evaluating the cost-effectiveness of an achievable near-term DERs portfolio to meet a portion of Virginia's future energy needs. The analysis uses Virginia-specific inputs for costs, performance, and deployment assumptions, which are documented in Appendix B. The objective is to provide a data-driven comparison of both benefits and costs of meeting future system needs using DERs rather than new fossil fuel resources.

3.1 Cost-Effectiveness Methodology

Cost-effective tests are used to evaluate if the benefits of DERs exceed the costs of the program. Passing the cost-effectiveness test demonstrates that the programs and/or portfolios are prudently incurred costs, which provides rationales not only for the utility to invest in those programs, but also for those costs to be recoverable through rates. There are multiple, varying cost-effectiveness tests because there are varying perspectives about benefits and costs. For example, an incentive payment is a benefit for participating customers but a cost for the utility.

Virginia utilities had been utilizing four different cost tests—The Participants Test, the Utility Cost Test, the Ratepayer Impact Measure Test, and the Total Resource Cost Test—none of which provided a full accounting or complete consideration of Virginia's state-specific policies. The cost tests were sometimes contradictory, as a program could pass one but fail another, making decision-making arbitrary and inconsistent. In recognition of this challenge, the Virginia legislature directed the SCC to "promulgate regulations establishing a single, consistent cost-effectiveness test for use in evaluating proposed energy efficiency programs," [78] which the SCC released in May of 2025.[79] Beginning in 2029, utilities are to analyze cost effectiveness primarily using a **Virginia jurisdiction-specific test (JST)**, with the Total Resource Cost (TRC) test used as well as for a comparative assessment. Table 13 summarizes each of the cost-effectiveness tests.

[78] Virginia 2024 Senate Bill 565/House Bill 746.

[79] Virginia State Corporation Commission, *Order Establishing Rulemaking*, Case No. PUR-2024-00120, (May 13, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/85j301!.PDF.

Table 13. Cost-Effectiveness Tests Used in Virginia

Test	Perspective	Key Question Answered	Categories of Costs and Benefits Included
Participants Test (PT)	Program participants	*Will the customers who participate in the program be better off financially?*	Includes participants' bill savings, incentives, out-of-pocket costs, and non-energy benefits that accrue directly to participants.
Utility Cost Test (UCT)	The utility system	*Will utility system costs be reduced?*	Includes avoided energy, capacity, and T&D costs versus program administration costs and incentives paid by the utility. Excludes participant costs/benefits.
Ratepayer Impact Measure Test (RIM)	Non-participating ratepayers	*Will rates go up for customers who do not participate?*	Includes utility system avoided costs, program costs, and lost revenues from reduced sales. Determines rate impacts, not overall cost-effectiveness.
Total Resource Cost Test (TRC)*	Utility system + participating customers	*Will total costs to the utility plus participants be reduced?*	Includes utility system avoided costs plus participant costs, plus the total cost of acquiring or installing DERs measure, including utility incentives and the remaining incremental project cost paid by the participating customer (net of additional incentives).
Virginia Jurisdiction-Specific Test (JST)*	Emphasizes impacts on the utility system and customers	*Is the program beneficial under Virginia's statutory cost-effectiveness criteria?*	Includes both utility system and societal benefits/costs, such as program incentives and avoided compliance costs. It differs from a TRC by including state-specific policy factors and excluding participant non-energy benefits unless explicitly authorized.

* Indicates that this test will be used in Virginia after 2028.

This analysis uses a cost-effectiveness test that aligns most closely with the preliminary Virginia JST framework. The Virginia JST is based upon the National Energy Screening Project's National Standard Practice Manual for Benefit Cost Analysis of Distributed Energy Resources.[80] The Virginia JST has not yet been implemented and does not yet have a methodology for how to monetize all benefits. Accordingly, this analysis monetizes all costs but only includes values for benefits with readily monetized elements using existing methods. This approach results in a conservative cost-effectiveness estimate because it does not include all benefits. Table 14 details which benefits and costs associated with the Virginia JST are monetized for this analysis.

[80] Virginia 2024 Senate Bill 565/House Bill 746 states that "In developing this test, the Commission shall (i) refer to the cost-benefit analysis framework and process contained in the National Energy Screening Project's National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, in addition to any other materials deemed relevant by the Commission".

Table 14. Monetized Cost-Effectiveness Elements

Impact Type	Impact	Approach
Energy	**Energy Generation**	**Monetized**
	Capacity	**Monetized**
	Environmental Compliance	Qualitative
	RPS/CES Compliance	**Monetized**
	Market Price Effects	Qualitative
	Ancillary Services	Qualitative
Transmission	**Transmission Capacity, System Losses, & O&M**	**Monetized**
Distribution	**Distribution Capacity, System Losses, & O&M**	**Monetized**
	Distribution Voltage	Qualitative
General	**Financial Incentives**	**Monetized**
	Program Administration	**Monetized**
	Utility Performance Incentives	Qualitative
	Credit and Collection	Qualitative
	Risk	Qualitative
	Reliability	Qualitative
	Resilience	Qualitative
Fuels	**Fuel (includes Delivery Costs and O&M)**	**Monetized**
Societal	**Greenhouse Gas Emissions**	**Monetized**
	Other Environmental Impacts	Qualitative
	Public Health	**Monetized**
	Resilience	Qualitative

Source: Created using Table 1 and Table 2 from Virginia State Corporation Commission, Order Establishing Rulemaking, Case No. PUR-2024-00120, (May 13, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/880h01!.PDF .

The monetized values of the DERs are based on avoided costs. While there is overlap with the categories of benefits described in Chapter 2, the elements of the cost-effectiveness test are independent and applied using the test's specific framework. Impacts can be either benefits or costs, depending on if they result in net savings or net costs. Generally, financial incentives and program administration are costs, while the remaining impacts result in benefits.

See *Appendix B* for the input values and assumptions for each monetized impact type.

3.2 Composition of DERs Portfolio

To estimate the value of DERs it is necessary to first identify the portfolio, as the composition of DERs and scale of the portfolio will determine the ultimate valuation. A portfolio view is necessary because it is through deploying DERs at scale that enables the resources to compete with traditional supply-side or centralized investments. Key to the scalability is the assumption that DERs are managed collectively to maximize grid benefits, which is why the VPP is critical to ensure cohesive and automated participation of the portfolio resources.

This analysis evaluates a DERs portfolio using 2028 as the representative year based upon established values for two elements of DERs for this time period: energy efficiency targets for Dominion and APCo, as well as the VPP program pilot for Dominion. Table 15 summarizes the levels of each element of the DERs portfolio evaluated in the cost-effectiveness analysis (i.e., the net increase between current levels and the 2028 DERs portfolio). The data sources and assumptions for the current and future values are detailed in the subsections that follow.

Table 15. Total and Net DERs Portfolio Evaluated for Cost-Effectiveness

	Current	2028	Net Increase
Energy Efficiency	1.6 GWh	4.0 GWh	**2.4 GWh**
Distributed Solar (<1 MW)	600 MW	1,100 MW	**500 MW**
Distributed Solar (1-3 MW)	40 MW	400 MW	**360 MW**
VPP Total	0 MW[81]	450 MW	**382 MW**
DR	*60 MW*	*160 MW*	*100 MW*
BTM Battery	*7 MW*	*22 MW*	*15 MW*
EV	*<1 MW*	*121 MW*	*120 MW*
BYOD Aggregator	-	*147 MW*	*147 MW*

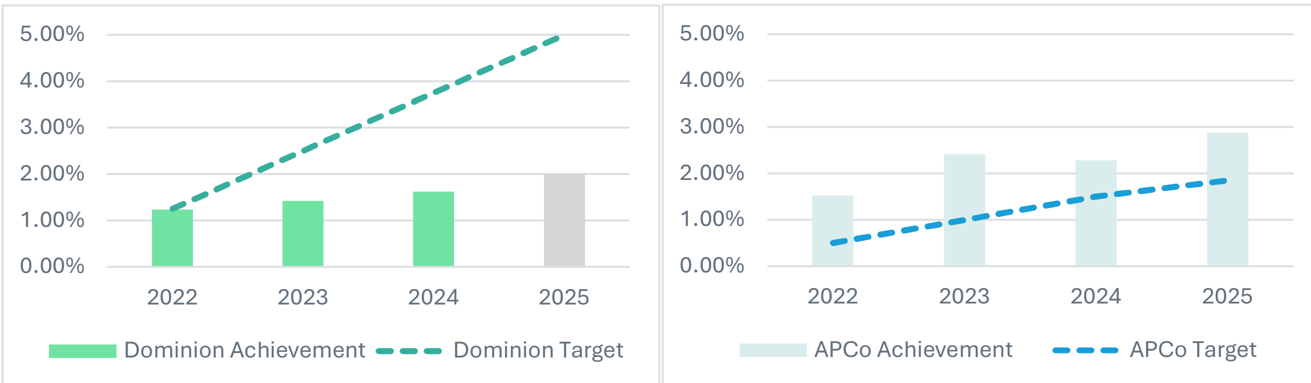
3.2.1 Energy Efficiency

The VCEA, codified through the Code of Virginia, established minimum levels of annual energy savings from energy efficiency for Dominion and APCo for the years 2022 through 2025.[82] At least 15% of such proposed costs of energy efficiency programs are required to be allocated to programs designed to benefit low-income, elderly, or disabled individuals or veterans. The levels of annual energy savings required for each utility are specified as a percentage of retail sales, with 2019 retail sales as the baseline. Baseline 2019 retail sales are 14,452,000 MWh for Appalachian Power[83] and 68,231,360 MWh for Dominion.[84]

[81] While there are approximately 68 MW total of existing demand response (DR), behind-the-meter (BTM) battery, and electric vehicles (EVs) in Virginia, they are not currently aggregated into a VPP program where they can be dispatched uniformly. Accordingly, the value of existing VPPs in Virginia is zero. Including the existing DERs, the 2028 VPP portfolio would be comprised of approximately 380 MW in net new resources.
[82] Code of Virginia § 56-596.2. *Energy efficiency policy and programs; financial assistance for low-income customers*
[83] Virginia State Corporation Commission, *Report of Mathias Roussy, Jr., Hearing Examiner* (November 19, 2024), Case No. PUR-2024-00134, page 18, https://www.scc.virginia.gov/docketsearch/DOCS/82mf01!.PDF
[84] Virginia State Corporation Commission, *Report of Mathias Roussy, Jr., Hearing Examiner* (November 12, 2024), Case No. PUR-2023-00227, page 14, https://www.scc.virginia.gov/docketsearch/DOCS/82%24401!.PDF.

Dominion met the first target in 2022 but has since fallen well below target levels, with the gap increasing each year. APCo has exceeded the 2022 through 2025 targets—despite year-to-year EE savings declining from 2023 to 2024 by 25,043 MWh. Figure 2 charts the historical targets compared to achievements for each of the two covered utilities.

Figure 2. VCEA Energy Efficiency Targets & Achievements (%, 2022-2025)



Source: Code of Virginia § 56-596.2. (APCo): *Report of Mathias Roussy, Jr., Hearing Examiner, Case No. PUR-2024-00134* at 18. (Dominion): *Report of Mathias Roussy, Jr., Hearing Examiner, Case No. PUR-2023-00227* at 14 and VA SCC *Combined Annual Report on Energy Efficiency Programs* at 4 (for the year 2024). Note: Dominion values for 2025 are an estimate (as values have not yet been released).

The SCC recently approved energy efficiency targets for the years 2026 through 2028 for Dominion[85] and APCo.[86] Figure 3 details the upcoming targets for each utility. Due to the lagging historical achievements, Dominion's targets were decreased such that the original 2025 target of 5% is now the requirement for 2028. APCo's targets continue on a similar trajectory over the next three years.

In 2028 the energy efficiency savings targets for both utilities will total 3,989,648 MWh, an **increase of approximately 2.4 GWh** from current achievement levels.[87] This level of achievement is **deemed to be feasible by the SCC**,[88] but will require significant investments to more than double energy efficiency saving levels for Dominion.

[85] Final Order Case No. PUR-2023-00227, (February 27, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/841401!.PDF
[86] Final Order Case No. PUR-2024-00134, (February 28, 2025), http://scc.virginia.gov/docketsearch/DOCS/844501!.PDF
[87] Dominion has not yet reported their 2025 achievements. Assuming a similar 2025 achievement as 2024 would require an increase of 2,469,187 MWh for both utilities to achieve 2028 target levels, so 2.4 GWh is used as the estimate to account for potential saving increases in 2025.
[88] Final Order Case No. PUR-2023-00227, (February 27, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/841401!.PDF

Figure 3. VCEA Energy Efficiency Targets (2026-2028)

Year	Dominion Target (%)	Dominion Target (MWh)	APCo Target (%)	APCo Target (MWh)
2026	3.0%	2,046,941 MWh	3.0%	433,808 MWh
2027	4.0%	2,729,254 MWh	3.5%	505,820 MWh
2028	5.0%	3,411,568 MWh	4.0%	578,080 MWh

Source: MWh calculated based on percentage targets established by SCC and 2019 baseline retail sales

3.2.2 Distributed Solar

The VCEA has two provisions that specify target levels of distributed generating resources: the "1% RPS carve-out" and the "small-scale solar requirement." The first applies to distributed resources less than 1 MW, while the second applies specifically to solar less than 3 MW.

1% RPS Carveout (<1 MW)

Dominion and APCo are required to participate in a renewable energy portfolio standard program (RPS Program) that establishes annual goals for the sale of renewable energy to retail customers. For the year 2028, the RPS program requirement (calculated as the percentage of the total electric energy sold in the previous calendar year) is 24% for APCo and 35% for Dominion.[89]

The "RPS carveout" applies only to Dominion and requires that 1% of the RPS program requirement in any given compliance year with "solar, wind, or anaerobic digestion" resources of 1 MW or less,[90] with a maximum of 3 MW at a single location and 25% composed of low-income qualifying projects (or, if not available, located on or adjacent to schools).[91]

Based on Dominion's load forecasts for the year 2027 of 104,327 GWh,[92] 1% of the 35% RPS requirement would equal 365,145 MWh, approximately 210 MW of nameplate capacity (assuming a 20% capacity factor). The company is already achieving more than this 1% carveout requirement value—**for 2024 Dominion reported 551 MW nameplate capacity for distributed solar, approximately 340 MW more than what will be necessary for compliance in 2028.**[93]

Because the target is not larger than current levels of distributed solar for Dominion—and because APCo does not have a RPS carve-out requirement—this analysis assumes a more aggressive target for the 2028 DERs portfolio. Table 16 details the amount of distributed generation required in 2028 at varying RPS carve-out levels and including APCo in the requirement.[94] Only 3% and higher values result in a requirement that is larger than current levels of small-scale distributed solar generation.

[89] Code of Virginia § 56-585.5.C.
[90] For purposes of this analysis all distributed generation less than 1 MW under the RPS carveout is assumed to come from solar, rather than small-scale wind or anerobic digestion.
[91] Code of Virginia § 56-585.5.C.2.
[92] Dominion 2025 IRP Update, *Figure 2.1.9: 2025 Company Load Forecast*.
[93] EIA-861 (2024), Virginia Electric & Power Company, Distribution (5 MW), and Net Metering (546 MW).
[94] APCo's 2027 load forecast is 16,510 GWh: Appalachian Power, "2022 Integrated Resource Plan" (April 29, 2022), Exhibit A-2a, https://rga.lis.virginia.gov/Published/2022/RD206/PDF

Table 16. Distributed Solar in 2028 Under Varying RPS Carve-Out Levels (1% to 5%)

	1%	2%	3%	4%	5%
Dominion (MWh)	365,145	730,289	1,095,434	1,460,578	1,825,723
APCo (MWh) (not mandated)	39,624	79,248	118,872	158,496	198,120
Total (MWh)	404,769	809,537	1,214,306	1,619,074	2,023,843
Total (MW)	**231**	**462**	**693**	**924**	**1,155**
2024 Small Scale Solar: 600 MW (~1 GWh), Equal to 2.6% of 2028 RPS Requirement					

Note: Total MW assumes a 0.2 capacity factor for solar to estimate nameplate capacity.

Distributed solar has a nexus with distributed storage as the two are commonly paired together for a generation source to charge the behind-the-meter storage resources. The VCEA requires an additional 20 MW of distributed storage by 2028 (see next section for further details on the small-scale battery storage requirement). Assuming that higher levels of solar are needed to unlock additional battery storage is the basis for an increased RPS carve-out. Statewide as of 2024, Virginia has approximately 1 MW of distributed battery storage for every 100 MW of small-scale solar nameplate capacity (733 MW of total solar less than 1 MW and 7 MW for behind-the-meter battery storage).[95] Assuming future battery storage can be paired equally with existing and new distributed solar, approximately **500 MW of new distributed solar less than 1 MW** could be utilized to unlock higher levels of behind-the-meter battery storage—corresponding to approximately 1,100 MW total nameplate small-scale solar, a similar level as the 5% RPS carve-out level for 2028.

Small-Scale Solar Requirement (<3 MW)

The VCEA also specifies minimum levels of procurement of zero-carbon electricity generating capacity by 2035,[96] with requirements for both Phase I and Phase II utilities:

- Dominion must "construct, acquire, or enter into agreements" to purchase 16,100 MW of new solar or onshore wind, of which 1,100 MW must be small-scale (defined as less than 3 MW nameplate).[97]
    - Of the smaller-scale generation, a minimum of 35% must be owned by entities other than the utility.
    - A minimum of 200 MW of the 16,100 MW total must be on previously developed project sites (e.g., disturbed lands).
    - Interim targets prior to 2035 require 6,000 MW (of the total 16,100 MW) by 2028 (3,000 MW by the end of 2024 and another 3,000 MW by the end of 2027). While

[95] EIA-861, EIA-860, and EIA-851 (2024).
[96] Code of Virginia § 56-585.5.D.
[97] Code of Virginia § 56-585.5.D.2.

not mandatory, the small-scale (less than 3 MW) proportion of these interim targets would be 410 MW by 2028**.**

- APCo must construct, acquire, or enter into agreements to purchase 600 MW of new solar or onshore wind. Unlike Dominion, there is no requirement that any of this generation capacity be for small-scale resources.

A value of **400 MW of distributed solar between 1 MW and 3 MW** is used for the DERs portfolio analysis. Because Dominion must "construct, acquire, or enter into agreements" for the small-scale solar less than 3 MW, this analysis assumes that this solar capacity is separate and additional to the distributed solar less than 1 MW required for the RPS carveout. The 400 MW value of solar between is meant to be illustrative as an order of magnitude estimate, were there to be interim requirements for small-scale solar procurement prior to 2035.

As of 2025 there are approximately 40 MW of distributed solar between 1-3 MW. This value includes nearly 17 MW of shared solar as part of Dominion's Shared Solar program in-service by the end of 2025 (APCO's shared solar program's earliest in-service date is in 2026).[98, 99] Under Virginia's Shared Solar Statue,[100] Dominion and APCo customers are able to subscribe to a shared solar project and receive a monthly bill credit. The remaining 22 MW of the 40 MW of current nameplate capacity solar between 1 and 3 MW are either utility-owned, contracted with power purchase agreements (PPAs), or non-net metering distributed solar (for service to Dominion or APCo customers only).[101, 102]

3.2.3 VPP

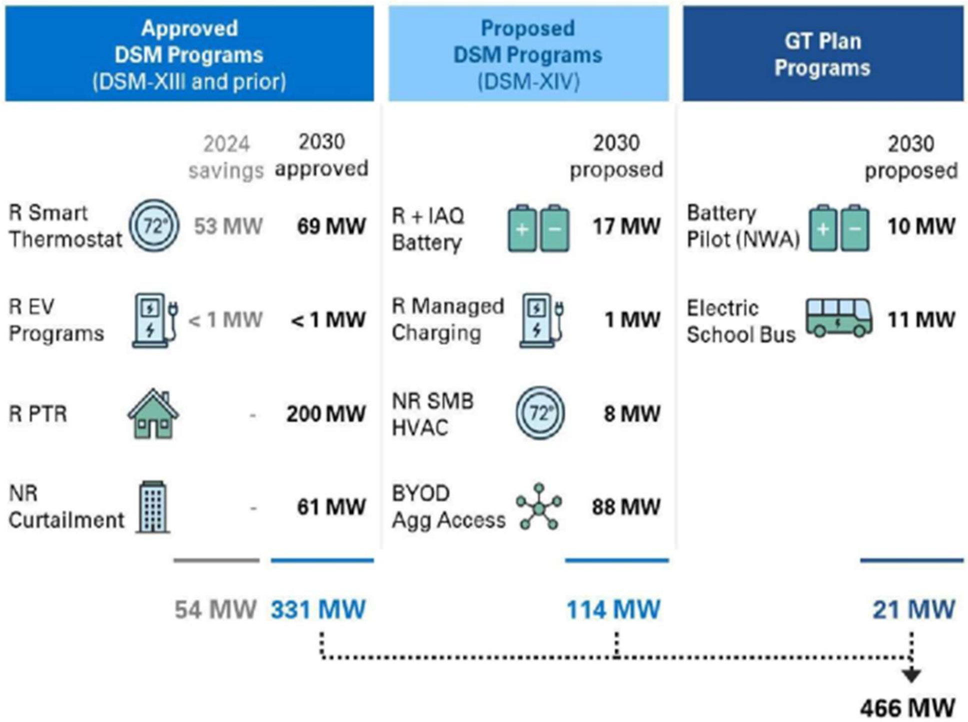
Dominion is required by the Community Energy Act of 2025 to create a Virtual Power Plant (i.e., VPP) pilot program of up to 450 MW. This capacity target is explicitly defined as the "aggregations of distributed energy resources" and does not strictly correspond to nameplate or peak capacity measurements. [103] The Act specifies that the VPP should incentivize new customers as well as incorporate existing DSM programs. Specific mandates for the VPP Pilot include the incorporation of at least 15 MW sourced from residential battery storage and the integration of an electric school bus program component. The pilot is expected to launch in the first quarter of 2027 and last for 18 months, concluding by July 1, 2028. Upon this conclusion, the Commission is mandated to initiate formal proceedings to establish a permanent VPP program for the electric utility.

Dominion submitted their VPP Pilot proposal on December 1, 2025.[104] Dominion proposes a total of 466 MW of participating resources by 2030 (Figure 4). Much of the near-term capacity attributed to the VPP is drawn from existing or previously approved demand response programs, most notably the Residential Peak Time Rebate program, which relies on voluntary, customer-initiated behavioral response (via email or text) rather than automated or dispatchable control. As a result, a

[98] Dominion Energy, *Shared Solar Program*, Project Awarded Capacity table, https://www.dominionenergy.com/virginia/renewable-energy-programs/shared-solar-program
[99] Appalachian Power, *Shared Solar Program*, Project Awarded Capacity table, https://www.appalachianpower.com/clean-energy/renewable/solar/shared-solar-program
[100] Code of Virginia § 56-594.3 Shared solar programs; Phase II Utility; § 56-594.4. Shared solar programs; Phase I Utility.
[101] EIA-861 (2024), Non-Net Metering Distributed, Photovoltaic.
[102] EIA-860 (2024), Schedule 3, 'Solar Technology Data' (Operable Units Only).
[103] Virginia 2025 HB 2346/SB 1100.
[104] Direct Testimony of Courtney S. Young.

significant share of the VPP's projected capacity is not firm, automated, or directly controlled through Distributed Energy Management Systems (DERMS).

Figure 4. Dominion's VPP Pilot Potential Pathway



Source: Application of Virginia Electric and Power Company for approval of its Virtual Plant Pilot Program under § 56:585.1:16 of the Code of Virginia. Case No. PUR-2025-00211, Doc No. 251210018, Schedule 1, Figure 7.

Focusing only on the dispatchable components within the VPP Pilot—excluding residential peak time rebates (PTR) and non-residential (NR) curtailment—leaves approximately 205 MW for the VPP program by 2030. There is approximately 53 MW of existing capacity that can be used for the VPP, meaning that Dominion proposes approximately 152 MW of new net resources for the VPP Pilot. Most incremental growth and coordination of new resources for the VPP Pilot will come through the BYOD Aggregator Access (88 MW) rather than through utility-administered programs. As a result, the pace, composition, and performance of future VPP capacity additions would be largely dependent on aggregator participation and market response, rather than on direct utility procurement or enrollment.

While there are approximately 68 MW total of existing demand response (DR), behind-the-meter (BTM) battery, and electric vehicles (EVs) in Virginia,[105] they are not currently aggregated into a VPP program where they can be dispatched uniformly. The cost-effectiveness analysis instead evaluates a more ambitious VPP Pilot program of 382 MW total participating dispatchable nameplate capacity (Table 17), reflecting achieving a total 450 MW from a larger buildout of Dominion's demand response, EV participation, BTM battery storage, and the BYOD Aggregator program, without needing to rely on non-automated peak-time-rebates or curtailment.

[105] EIA-860 (2024).

Table 17. Modeled VPP Portfolio for Cost-Effectiveness Analysis (2028)

VPP Element	Existing	Incremental	Total
Demand Response	60	**100**	160
Battery Storage	7	**15**	22
EV	1	**120**	121
BYOD Technology Aggregator	0	**147**	147
VPP Pilot Total	**68**	**382**	**450**

Source: Existing values are statewide based on EIA-860 and EIA-861 data for 2024.

The VPP portfolio evaluated herein is based upon statewide existing values for each VPP element. According, this representative portfolio could reflect **either an expanded VPP Pilot for Dominion and/or augmenting statewide participation by requiring a VPP Pilot for APCo as well**. The total values by 2028 are based upon distinct feasibility assumptions for each VPP element, as follows:

- **DR of 100 MW** incremental peak load reduction by 2028. The total value equates to the sum of Dominion and APCo's demand response target for 2028 of 132 MW and 29 MW, respectively.[106, 107]
- **Distributed Battery Storage of 15 MW** of total nameplate is driven by regulatory requirements and assumes that all new battery additions participate in the VPP Pilot. The VCEA requires 3,100 MW of energy storage by 2035 (2,700 MW for Dominion and 400 MW for APCo), with no interim targets.[108] There is a goal for 10% of such energy storage to be installed behind the meter.[109] Separately, the Community Energy Act requires at least 15 MW of residential BTM battery storage for participation in the VPP Pilot.[110] Accordingly, this analysis uses an incremental 15 MW value for 2028, assuming that is all net new battery that contributes to both the VPP Pilot and VCEA requirements.[111] With the 7 MW of existing battery storage between Phase I and II utilities,[112] the total in 2028 is 22 MW.
- **EV participation of 120 MW** in managed charging programs (demand response and/or time-of-use). By 2028, EV adoption is expected to contribute 237 MW of coincident peak load in Dominion's territory alone.[113] This analysis assumes that 50% of this EV load is enrolled in an EV Demand Response or managed charging program (EV VPP), enabling utilities to curtail or shift charging during peak periods.

[106] Dominion Energy, Virginia Electric and Power Company - 2024 Integrated Resource Plan ("Dominion's 2024 IRP"), Virginia SCC Case No. PUR-2024-00184, filed October 15, 2024, Appendix 3E-2 and 3F-2 summing all programs marked (DR) inc. Water saving, Thermostat, EV charging.
[107] APCo's target is calculated proportionally from Dominion's target, assuming an approximately 400% increase from 2024 demand response program savings of 7.3 MW.
[108] Code of Virginia § 56-585.5.E.
[109] Code of Virginia § 56-585.5.D.4.
[110] Virginia HB 2346/SB 1100, https://lis.virginia.gov/bill-details/20251/SB1100.
[111] Dominion currently has 3 MW of battery storage while APCo has 4, per EIA/861 (2024).
[112] EIA-861 (2024).
[113] Dominion's 2024 IRP, Appendix 2A, Figure 6.

- **BYOD Technology Aggregator of 147 MW** of nameplate participating resources. This is a calculated value, equal to the remaining amount necessary to bring the total VPP to 450 MW for 2028, including existing resources.

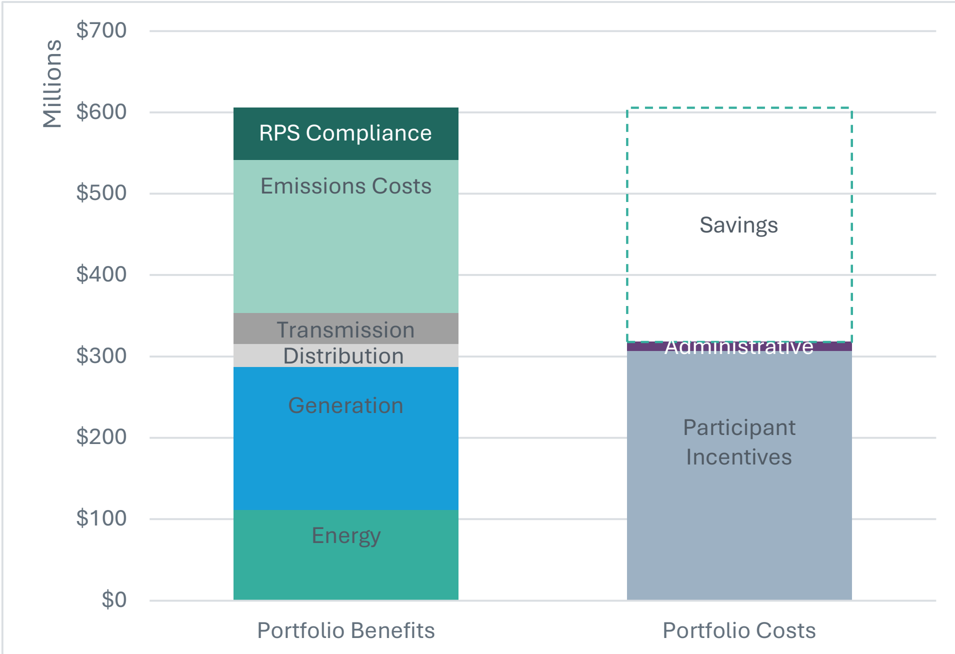
3.3 Cost-Effectiveness Test Results

The DERs portfolio delivers $606.1 million in annual monetized benefits against $317.9 million in annual costs, resulting in **$288.2 million in annual net savings and a cost-effectiveness ratio of 1.91** (Table 18). These results explicitly consider opportunity cost, comparing DERs performance to the avoided costs of fossil-fuel alternatives—namely natural gas CTs for capacity and CCs for energy. Benefits are categorized in capacity and energy value streams: avoided generation capacity totals $175.8 million, while avoided transmission and distribution add $38.3 million and $28.4 million, respectively. On the energy side, the portfolio results in energy savings of 3.8 million MWh, yielding $113.2 million in avoided energy costs, $187.2 million in avoided emissions costs, and $63.2 million in RPS compliance value. Figure 5 displays the magnitude of the cost-effectiveness test components and resulting savings.

Table 18. Annualized Cost-Effectiveness Results

Component	Result
Nameplate Capacity (MW)	1,242 MW
Reliable Capacity (MW)	590 MW
Energy Generation (MWh):	3,803,440 MWh
Benefits:	
Capacity Value	
Avoided Generation (inc. Firm Fuel Transport) ($)	$175.8 million
Avoided Distribution (inc. Losses + O&M) ($)	$28.4 million
Avoided Transmission (inc. Losses + O&M) ($)	$38.3 million
Energy Value	
Avoided Energy Cost (inc. fuel costs) ($)	$113.2 million
Other Values	
Avoided Emissions Cost ($)	$187.2 million
RPS Compliance ($)	$63.2 million
Total Value ($/yr):	**$606.1 million**
Costs:	
Utility Costs ($)	
Participant Incentives ($)	$306.6 million
Administrative costs ($)	$11.3 million
Total Cost ($/yr)	**$317.9 million**
Cost-Effectiveness:	
Savings ($)	**$288.2 million**
Cost-Effectiveness Ratio	**1.91**

Figure 5. Annualized Cost-Effectiveness Components



Crucially, this analysis monetizes only a subset of value streams—those with readily quantifiable benefits—while excluding non-monetized elements such as resilience, risk reduction, and ancillary services. Even under this conservative scope, the portfolio demonstrates strong cost-effectiveness, with benefits exceeding costs by a wide margin. Most program costs stem from participant incentives and administrative overhead yet the benefits exceed the costs, leading to a cost-effectiveness value higher than one. The 1.91 ratio underscores that DERs are not only competitive but economically lower cost than traditional supply-side investments, even when evaluated against the narrow lens of monetized costs alone.

A more restricted view of cost-effectiveness, which considers only benefits from avoided infrastructure elements, underscores the robustness of the results. **Considering only avoided energy, generation capacity, transmission, and distribution as benefits of DERs—excluding avoided costs for emissions and RPS compliance—still results in the portfolio being cost-effective, yielding annual savings of $37.8 million.**

3.4 Qualitative Benefits

The DERs portfolio results in 590 MW of reliable, firm capacity—equal to the same reliable capacity provided by a 950 MW natural gas combustion turbine (CT) peaking plant or an 800 MW natural gas combined cycle (CC) non-peaking plant. **This comparison underscores the efficiency of distributed resources in delivering dependable peak capacity without the capital intensity, fuel risks, or environmental harms of fossil fuel generation.**

By leveraging aggregation and diversity, the DERs portfolio achieves similar reliability at a fraction of the scale and cost, while avoiding emissions and compliance liabilities inherent to fossil-fueled plants. Unlike a new CT or CC unit, which requires years of development and exposes ratepayers to volatile gas prices, DERs can be deployed rapidly and modularly, aligning investments with actual system needs. This flexibility reduces planning risk and mitigates stranded asset concerns—critical advantages as Virginia faces uncertain load growth and evolving policy mandates. Even when evaluated strictly on monetized avoided costs, the portfolio demonstrates that distributed resources are not only technically viable but economically superior to conventional supply-side options.

The benefits from DERs can be augmented through strategic deployment. By avoiding greenfield development, DERs minimize environmental disruption and preserve cultural and aesthetic values, while enabling distributed generation closer to load centers—reducing transmission needs and improving grid resilience. These locational advantages, though not monetized in the cost-effectiveness analysis, represent system and societal value that strengthens the case for scaling DERs deployment statewide. Participant and societal benefits are discussed further in Section 2.4 and Section 2.5, respectively.

4 Implementation Risks and Policy Pathways

To realize the full potential of DERs and associated cost savings, Virginia must navigate two critical dimensions: mitigating risks that could derail near-term progress and implementing policy pathways that enable sustained growth. The following subsections examine these challenges and opportunities—first by identifying key risks to achieving the near-term portfolio of DERs by 2028, and then by outlining actionable policy recommendations to strengthen implementation and long-term success.

4.1 Near-Term Achievement Risks

While this analysis demonstrates that a significantly expanded portfolio of DERs is cost-effective and feasible by 2028, several material risks could impede near-term achievement if not addressed. These risks stem less from technical or economic limitations than from policy design, program implementation, and regulatory enforcement. Insufficiently ambitious targets, the structure of the VPP Pilot, and inconsistent accountability mechanisms for utility compliance create uncertainty around whether Virginia will realize the DERs levels assumed in this analysis on the required timeline.

Lack of Interim Targets and Allowing Backsliding.

A central risk to near-term DERs deployment is that existing statutory and regulatory targets are not sufficiently ambitious relative to what this analysis shows is both achievable and cost-effective, particularly for distributed solar and energy efficiency. For example, the small-scale 1% RPS carve out for distributed generation of less than 1 MW for 2028 is already being exceeded by Dominion today, meaning that compliance with the statutory minimum does not require additional near-term deployment. In practice, this creates little incentive for continued growth despite the economic and system value of additional distributed solar.

This issue is compounded by the structure of several VCEA requirements that set final targets in 2035 without establishing interim milestones. Small-scale distributed resources and battery storage have milestones for the utility-scale generation only. Table 19 shows the interim targets as required under VCEA for the total amounts through 2035, as well as a schedule for what the interim targets would be if they also applied to the small-scale generation as well as BTM energy storage. Both resource categories require sustained, incremental investment over time, yet the **absence of interim targets allows deployment to be deferred, increasing the likelihood of a compressed and more expensive build-out later in the decade or of targets ultimately being missed altogether.**

Table 19. Actual & Proposed Interim Targets for Distributed Resources & BTM Battery Storage

Solar or Wind (Code of Virginia § 56-585.5.D.2) Incremental Targets			Energy Storage (Code of Virginia § 56-585.5.D.4) Incremental Targets		
Year	Interim Targets (MW) (All Sizes)	Proposed Targets for <3 MW (MW)	Year	Interim Targets (MW) (Dominion & APCo)	Proposed Interim Targets for BTM
2024	3,000	200	**2025**	275	27.5
2027	3,000	200	**2030**	1,075	107.5
2030	4,000	300	**2035**	1,750	175
2035	6,100	400			
Total	**16,100**	**1,100**	**Total**	**3,100**	**310**

Distributed solar is a key component needed to achieve higher levels of distributed storage, particularly behind-the-meter batteries that rely on on-site generation for charging and customer value propositions. Current levels of distributed storage in Virginia remain low relative to VCEA mandates, indicating substantial untapped potential. However, **without clearer near-term expectations for both small-scale solar and storage, which could be clarified through interim requirements, the complementary growth assumed in this portfolio may not materialize on schedule**.

There are additional concerns about failing to meet targets for BTM battery storage. While the VCEA does not impose specific interim targets yet, the VPP Pilot, as required by the Community Energy Act, requires Dominion to propose programs incentivizing residential customers to purchase battery storage devices for at least 15 MW through the term of the pilot program (July 1, 2028). **Despite this requirement, Dominion's proposed VPP Pilot does not specify 15 MW of residential or other BTM battery storage by 2028—proposing instead to meet the requirement by 2030**.[114]

Energy efficiency presents a related, but distinct, risk. Although efficiency targets exist for the near term, recent revisions reflect backsliding rather than increased ambition. **Dominion's original statutory requirement to reach 5% cumulative savings by 2025 has now been delayed until 2028 due to underperformance**. While the revised targets may be achievable, this history raises concerns that near-term energy efficiency deployment could again fall short absent stronger oversight and enforcement.

Design and Implementation Risks in the VPP Pilot

The structure of the current VPP Pilot proposal introduces another significant risk to near-term achievement of DERs capacity. While Dominion's proposed VPP Pilot is sized at 488 MW by 2030, a substantial portion of the proposed capacity relies on resources that do not function as a truly *virtual* power plant.[115]

Dominion's proposal depends heavily on their existing demand response programs for **Residential Peak Time Rebates (PTR) and non-residential curtailment which are manual, voluntary, and not**

[114] Direct Testimony of Courtney S. Young.

[115] See Figure 4 in Section 3.2.3.

directly dispatchable through a DERs management system. While these programs can contribute to peak reduction under favorable conditions, they do not provide the automated, reliable, and controllable capabilities that define a VPP. Residential Peak Time Rebates are conducted via email and/or text notifications, while non-residential curtailment is a mix of manual and automated demand response.

The grid value of the non-automated components of these programs is fundamentally different from that of connected devices such as batteries, smart thermostats, managed EV charging, or other controllable loads. As such, the 261 MW from these resources should not be considered eligible for the VPP portfolio. **Instead of relying on these manual offerings, Dominion should be instead shifting these customers to automated demand response**, such as smart thermostat or BYOD program participation.

Similarly, Dominion's proposal lacks sufficient detail regarding the incentive structure, performance requirements, and risk allocation for the BYOD aggregator component. Because most incremental VPP growth is expected to come from third-party aggregators rather than utility-administered programs, uncertainty around compensation, verification, and operational integration poses a real risk to enrollment levels and performance. Without clear rules and durable incentives, aggregator participation—and therefore VPP capacity—may fall well below modeled levels.

Inconsistent Enforcement and Utility Accountability

A final and cross-cutting risk is the lack of consistent accountability when utilities fail to meet DERs-related requirements. Although the VCEA establishes obligations for nearly all DERs elements evaluated in this report (including energy efficiency, distributed generation, storage, and renewable procurement) these requirements have not always been enforced in a manner that ensures timely compliance.

Dominion's failure to meet energy efficiency targets illustrates this challenge. **Rather than requiring corrective action when Dominion fell behind statutory targets, the targets themselves were revised downward and delayed.** This precedent increases the risk that future shortfalls in DERs deployment will similarly be addressed through target adjustments rather than through programmatic or managerial changes.

The SCC's conditional approval of new fossil-fueled capacity, such as the Chesterfield Energy Reliability Center (CERC), despite unmet policy requirements, further underscores this risk.[116] Approving capital-intensive supply-side resources while DERs obligations remain unfulfilled weakens the incentives for utilities to prioritize distributed alternatives and increases the likelihood that near-term DERs deployment will lag behind cost-effective levels.

Investor-owned utilities like Dominion and APCo are structurally disincentivized from prioritizing energy efficiency, demand response, and VPPs because these resources are largely treated as operating expenses rather than capital investments. Traditional cost-of-service regulation allows utilities to earn returns on capital expenditures but not on avoided costs or reduced sales, creating a

[116] CERC was approved by Final Order in Case No. PUR-2025-00037, despite Dominion failing to meet energy efficiency goals defined for VCEA, specifically, under VA Code § 56-585.1(A)(6): "The Commission shall not approve construction of any new utility-owned generating facilities that emit carbon dioxide as a by-product of combusting fuel to generate electricity unless the utility has already met the energy savings goals identified in § 56-596.2 and the Commission finds that supply-side resources are more cost-effective than demand-side or energy storage resources."

persistent bias ("Capex bias") toward utility-owned infrastructure over demand-side alternatives—even when the latter are more cost-effective for customers.

Absent stronger regulatory follow-through—such as conditioning approval of new generation on demonstrated progress toward DERs targets—**utilities face limited consequences for underperformance**. This dynamic represents a material risk to achieving the near-term DERs portfolio evaluated in this analysis.

4.2 Policy Recommendations

DERs are cost-effective solutions that can contribute to Virginia's growing demand while enhancing resilience, reducing emissions, and mitigating affordability concerns. Without expanded levels of DERs, Virginians could be forced into higher-cost alternatives, further threatening affordability in the state. There are two key strategies that comprise several intermediate actions that the Legislature and SCC can use to further expand and support DERs in Virginia:

1. **Strengthen and expand the VPP Pilot.** The current VPP Pilot is an important first step but is too small and short-term to demonstrate full system and ratepayer benefits. Under the current pilot program, DERs must be five MW or less in size, and Dominion must integrate up to 450 MW of aggregated capacity.[117] The initial phase of the pilot will conclude by July 2028, meaning the Pilot program will only span approximately 18 months. No other utilities in Virginia are required to offer a similar program at this time.

    a. **Increase the scale of the aggregator components within the VPP Pilot to support the transition to a robust, permanent program with ambitious procurement targets.** The current size of the pilot may limit participation and underrepresent the full system value that aggregated DERs can provide. Depending on the size of participating resources, the existing program cap may cause less than 100 MW of DERs to enroll in the pilot. Establishing a substantially larger minimum participation threshold (e.g., 450 MW minimum) would better reflect the VPP's potential to deliver grid flexibility, resilience, and ratepayer benefits, while still being small enough in scale to be feasible in a short timeframe.

    b. **Establish clear pathways for expansion to additional service territories, including a 50 MW pilot in Appalachian Power by 2028.** Virginians outside of Dominion's service territory would also benefit from participation in VPP programs. This requires establishing a process for expanding access to VPPs for the remaining utilities that power Virginia homes and businesses. For example, a 50 MW minimum VPP Pilot to serve Appalachian Power customers by 2028 would be a comparable program to what is required for Dominion.

    c. **Strengthen the VPP program by prioritizing automated (i.e., truly virtual) offerings.** Dominion's VPP Pilot currently includes 261 MW of manual, existing demand response (200 MW of peak time rebates for residential and 61 MW of non-residential curtailment). To fully realize the value of the VPP, the pilot should also include higher levels of truly virtual, automated offerings by mid-2028. While leveraging existing demand response resources is

[117] Code of Virginia § 56-585.1:16. Virtual power plant pilot program.

appropriate, automation is essential to enable rapid, coordinated dispatch of distributed energy resources, allowing them to operate as a single, integrated power plant. Participants that are already enrolled in existing demand response programs are likely strong candidates for VPP participation and could be enrolled through focused outreach to transition them into automated demand response offerings, such as smart thermostats.

2. **Address barriers to deployment by modernizing regulatory and utility structures that currently constrain DERs growth.** Virginia can expand DERs integration to capture additional system benefits, but this will require concerted efforts to alter existing laws and regulations, in addition to imposing new frameworks and rules to ensure an equitable and affordable energy transition.

    a. **Reduce Barriers to Participation**

        i. **Remove or increase the distributed generation (DG) caps.** The current sizing caps on DG restrict cost-effective customer participation and stunt the market for DERs. Customers that wish to install solar or another form of renewable generation at their home, farm, or business are not permitted to build their DG asset any larger than 25 kilowatts for a residential customer, 500 kilowatts for an agricultural customer, and three MW for a non-residential customer.[118] Further restrictions on system size limit the generating capacity to strictly meeting the energy needs of the site, with little room for upsizing to capture additional benefits from net metering or other programs that compensate the asset for the resilience and flexibility gains it can provide.

        ii. **Increase maximum size to qualify as "small-scale" from 1 MW/3 MW to 5 MW.** For compliance with Virginia RPS, Dominion is required to purchase renewable energy from small generators through two distinct tracks. Existing conditions on the sizing of these "small-scale" projects unnecessarily tempers the deployment of renewable DG and their contributions to state RPS targets. The first track stipulates at least 1% of Dominion's annual achievement of RPS requirements come from renewable energy projects that have generating capacity of one MW or less. The second track carves out a portion of Dominion's broader renewable energy purchases for small-scale solar projects. The utility must construct, acquire, or contract for 1,100 MW from solar assets that are three MW or less in size.[119] Despite the implicit support for small-scale renewable development in these RPS requirements, the disparate and conservative sizing rules that dictate compliant project sizes inhibit the contributions of small-scale generation to contribute to Virginia's clean energy goals. Establishing a uniform 5 MW sizing requirement for distributed renewables aligns DERs with the standard for Dominion's VPP Pilot and ensures that customers have a range of options when choosing resources that are most cost-effective for their home or business.

[118] Code of Virginia § 56-594. Net energy metering provisions.
[119] Code of Virginia § 56-585.5. Generation of electricity from renewable and zero carbon sources.

b. **Incentivize Asset Development**

i. **Allow large loads to directly fund DERs programs. Authorize the SCC to open proceedings to create a DERs compensation scheme.** Unlocking the full value of DERs includes allowing large loads to directly support DERs programs that provide a level of resources to counterbalance the load's demands on the grid. Programs permitted under this pathway can encourage the cohabitation of large loads and communities by incentivizing or requiring specific co-benefits, such as levels of investment in low-income communities, support of reliability goals, or assurance of progress towards additional priorities that are critical for an equitable and affordable grid. Certain large load customers have already demonstrated an interest in and set a precedent for direct funding of DERs programs; specifically, Google has done so in Nebraska ($300,000), Texas ($30 million), and Arkansas ($25 million).[120] Other states are considering or have implemented payments from data center large loads that are to be used to fund low-income weatherization programs (Indiana),[121] grid modernization (New Jersey),[122] and energy conservation programs (Minnesota).[123]

ii. **Ensure fair DERs compensation for the value provided to the grid to expand access and improve customer equity while maintaining grid cost recovery.** DERs provide endless value to the electric grid by granting flexible, responsive generation or load activities which bolster the supply and delivery of power to homes and businesses. It is critical for DERs to receive compensation that accurately and fairly reflects the benefits provided to the electric system, while balancing the need for utilities to recover costs associated with building and maintaining the grid. The financial and physical impacts of DERs need to be equitably shared amongst stakeholders to ensure that DERs are incentivized to provide service alongside protecting customers from excess charges.

iii. **Incentivize large loads to participate in automated demand response.** Virginia should establish a dedicated framework to incentivize large, flexible loads—such as data centers and other industrial customers—to participate in automated demand response. One promising approach is to fast-track interconnection for large loads that commit to being curtailable or dispatchable, similar to programs implemented by other utilities, including Portland General Electric.[124] This concept is also consistent with recent federal policy

[120] See Footnotes 38, 39, and 40.
[121] Indiana Utility Regulatory Commission, "In the matter of the verified petition of Indiana Michigan Power Company for approval of modifications to its industrial power tariff", *Cause No. 46097*, https://iurc.portal.in.gov/docketed-case-details/?id=b8cd5780-0546-ef11-8409-001dd803817e.
[122] Kate Plummer, "New Jersey Pushes Bill to Make Data Centers Pay for Electricity They Use", *Newsweek* (October 20, 2025), https://www.newsweek.com/new-jersey-pushes-bill-to-make-data-centers-pay-for-electricity-they-use-10906181
[123] Laws of Minnesota 2025, 1st Special Session, Chapter 12, https://www.revisor.mn.gov/bills/94/2025/1/HF/16/.
[124] GridCARE, "Portland General Electric and GridCARE Accelerate Hundreds of Megawatts of Data Center Power in Leading U.S. Market" (October 8, 2025), https://www.gridcare.ai/post/pge-and-gridcare-accelerate-hundreds-of-megawatts.

direction from Secretary Wright of the U.S. Department of Energy to FERC, which states: "the interconnection study of large loads that agree to be curtailable and hybrid facilities that agree to be curtailable and dispatchable should be expedited".[125] Enabling automated demand response from large loads can provide meaningful resource adequacy value, particularly with an established and transparent demand-side capacity accreditation methodology (e.g., effective load carrying capability, or ELCC), as recommended in a recent report for large loads in Nevada.[126] Notably, recent analysis of data center load growth in Virginia indicates that even modest levels of load flexibility could offset or defer the need for new capacity additions, reducing system costs while improving reliability.[127]

c. **Ensure Utility Integration**

i. **Ensure all utilities recognize DERs & VPPs using appropriate capacity accreditation that reflects their performance and reliability contributions, affirming they are recognized on equal footing with conventional resources in resource planning and capacity markets.** Powering Virginia's future in a clean, affordable, and equitable manner requires deploying flexible resources that can close the gap between supply and demand. Utilities must properly account for this grid value provided by DERs by accrediting and incorporating them into resource planning processes and capacity markets. Short- and long-term utility resource plans need to reflect the avoided costs of supplying and serving load, alongside the progression towards Virginia's RPS targets that are driven by DERs. Similarly, promoting DERs to a key role in capacity markets can improve available supply via generation reserves and reduce overall capacity demand, which in turn can reduce customer bills.

ii. **Identify and implement needed distribution system upgrades and advanced grid functions to enable dynamic DERs integration and participation.** Effective utilization of DERs requires a grid that capably and optimally interconnects and deploys flexible resources. In addition, the technology and infrastructure that enables widespread deployment of DERs must be safe and secure for all grid stakeholders. The existing pace of energy system modernization and its ability to integrate DERs falls short of what is needed for a flexible, and dynamic electric landscape. Virginia must engage in concerted and aggressive efforts to determine and execute necessary grid upgrades to enable DERs

[125] Chris Wright, "Secretary of Energy's Direction that the Federal Energy Regulatory Commission Initiate Rulemaking Procedures and Proposal Regarding the Interconnection of Large Loads Pursuant to the Secretary's Authority Under Section 403 of the Department of Energy Organization Act", *U.S. Department of Energy* (October 23, 2025), https://www.energy.gov/sites/default/files/2025-10/403 Large Loads Letter.pdf.
[126] Chris Cox, Aaron Schwartz, & Derek Stenclik, "Bringing Data Center Flexibility into Resource Adequacy Planning", *GridLab & Telos Energy* (September 2025), https://gridlab.org/portfolio-item/data-center-flexibility-nv-energy-case-study-report/.
[127] Energy + Environmental Economics, "Virginia Data Center Study: Electric Infrastructure and Customer Rate Impacts", *Prepared for the Virginia Joint Legislative Audit and Review Commission* (December 2024), https://jlarc.virginia.gov/pdfs/presentations/JLARC Virginia Data Center Study_FINAL_12-09-2024.pdf.

to reach their full potential. To ensure fair compensation for distribution system upgrades, the terms of Virginia's Distribution cost sharing program—which reduces first-mover penalties and spreads cost equitability across benefiting projects—must be upheld.[128]

iii. **Develop a set of targeted performance-incentive mechanisms (PIMs) to incentivize utilities to meet DERs targets and address utility biases that impede DERs deployment.** Customer-owned and sited DERs can present challenges to utility revenues by reducing energy usage or by replacing traditional electricity generation and delivery. Despite the numerous benefits to consumers by way of affordability, grid flexibility, and resilience, the impact on a utility's bottom line can result in technical or administrative barriers that restrict deployment and integration of DERs. By establishing a set of PIMs that reward utilities for meeting specific DERs targets, this can counteract inherent disincentives that impede DERs and ensure that utilities and customers are aligned on achieving a cleaner, more affordable grid.

iv. **Hold utilities accountable to existing VCEA, VEJA, and VPP requirements.** Virginia should not allow backsliding on VCEA targets and enforce compliance in SCC actions (e.g., approving CPCNs or cost recovery for new fossil fuel resources). Dominion's original statutory requirement to reach 5% cumulative energy savings by 2025 were delayed to 2028 due to underperformance—this backsliding should not be allowed to occur as targets have proven to be feasible and cost-effective. Under Virginia Code § 56-585.1(A)(6), no new carbon-emitting generation should be approved unless the utility has met annual energy efficiency goals. Including similar conditions for the minimum levels of DERs (including existing and new interim achievements) required under VCEA, as well as the VPP program, would help correct for the disincentives that utilities have to invest in distributed solutions.[129] Approval of new generation must be conditioned on demonstrated progress toward these targets, and cost recovery should occur through base rates—not automatic riders—unless statutory compliance is proven. These measures ensure low-cost, right-sized solutions are prioritized before ratepayers bear the burden of large infrastructure costs.

d. **Update Achievement Level Expectations**

i. **Create interim requirements for small-scale resource components.** As discussed in Section 4.1.1, adding interim requirements for small-scale solar and BTM battery storage would align with the utility-scale interim achievement requirements. This change would make it clear that continual progress is also expected for the small-scale resources prior to the full requirements in 2035, and promote the Commonwealth's goals of decarbonization, grid resilience, customer cost savings, and equitable access to clean energy benefits across all customer classes. Interim targets would also provide early

[128] Code of Virginia § 56-596.6.
[129] These disincentives are discussed further in subsection "e) Implement Performance Based Regulation (PBR) Features" below.

investments in these technologies, which would reinforce Virginia's policy to provide stability and certainty for the workforce and small businesses supporting these markets.

ii. **Implement small-scale resource solar requirement for APCo (none currently).** The existing RPS regime requires certain proportions of Dominion's compliant generation to be sourced from solar projects that are one to three MW in size (small-scale). This stipulation encourages the development of small, locally sited solar projects within Virginia to serve Dominion customers. APCo does not have a comparable requirement for small-scale solar. Establishing a small-scale solar provision would incentivize small, Virginia-based solar construction and allows APCo customers to rely upon local generation projects for their energy needs.

iii. **Increase the RPS carve out for DG from 1% to 5% beginning in 2028.** Presently, Dominion is required to meet 1% of its RPS targets with distributed generation that is one MW or less in size. In addition, one quarter of the proportion must be sited as a low-income qualifying project or located on or adjacent to a school. If expanded, these carveouts would promote more rapid deployment of small DG assets across Virginia and in low-income communities by raising standards for Dominion's investment in distributed generation.

iv. **Increase storage targets (maintaining 10% BTM distributed storage requirement).** Dominion and APCo are required to secure 2,700 MW and 400 MW, respectively, of energy storage capacity by 2035. In addition, the RPS law dictates that at least 10% of the storage must be behind-the-meter. The targets for storage need to be increased to reflect growing needs for reliable capacity as Virginia transitions to a clean energy future. Having the ability to store renewable energy and dispatch it whenever necessary is critical for controlling costs and assuring grid performance.

v. **Establish minimum DERs deployment levels and incentives for disturbed lands (parking lots, brownfields, landfills) to accelerate Virginia's brownfield priorities.** Dedicating a proportion of the 1,100 MW of small-scale solar by 2035 to disturbed lands—like what is required for 200 MW out of the 16,100 MW of utility-scale solar—would promote additional and more diverse brownfield development. Virginia's disturbed lands can play an important role in the state's energy future by serving as sites for DERs where there otherwise would have been little to no development. Coupling the growing need for a distributed, flexible energy system with Virgina's existing commitments to addressing brownfields can lead to numerous benefits for the communities that contain brownfields and may benefit from increased access to DERs.

vi. **Increase third-party development of small-scale solar and BTM storage from 35% to 65%.** Imposing a higher standard for investments in third-party owned solar assets provides direct financial opportunities for non-utility actors to develop solar in communities across Virginia.

e. **Implement Performance Based Regulation (PBR) Features**

i. **Develop a set of targeted performance-incentive mechanisms (PIMs), including updates to strengthen achievement of energy efficiency targets and select additional priority outcomes.** Implementing a set of PIMs allows Virginia to prioritize key energy outcomes and bolsters progress towards existing or potential energy goals. A PIM rewards or penalizes a utility based on their measurable performance in a certain area, so establishing standards by which utilities and customers can assess achievement of certain programs or priorities will incentivize activities that are supportive of the desired outcome. In Virginia, this can include a PIM related to energy efficiency, or other items that are critical for the state's energy grid.

ii. **Employ all-source competitive procurement in future utility resource procurement in a manner that allows participation from resource alternatives, including clean energy supply and demand-side management (DSM) solutions.** Requiring utilities to use this least-cost method for meeting energy demand is critical for supplying a grid that requires flexible and reliable clean energy. All-source competitive procurements are technology- and ownership-agnostic and provide opportunities for DERs and other energy resources that are typically excluded from utility procurement processes to provide generation, capacity, and grid services. Deploying DERs through a utility least-cost exercise benefits customers by avoiding the costs and emissions associated with traditional utility assets, incentivizing broader DERs market participation, and providing flexible and resilient energy resources.

iii. **Equalize Capital and Operating Expenses in utility ratemaking proceedings.** Traditional utility ratemaking typically incentivizes utilities to lean heavily on capital expenses to earn profits, while operating expenses are passed through to customers without markup. By deriving profits from large infrastructure projects and other capital expenses, utilities are not motivated to engage in capital or operating projects that can achieve the same grid outcomes for a lower cost. There are a handful of mechanisms that effectively "equalize" capital (Capex) and operating (Opex) expenditures by allowing for some or all Opex to be included in a utility's authorized earnings, or by rewarding or penalizing utilities for their performance on certain Opex or Capex programs. Requiring capital and operating expenses to have equal weight in ratemaking ensures utilities are committed to achieving operational and system efficiencies, which DERs are strongly suited to provide.

Appendices

Appendix A. Terminology

Bring Your Own Device (BYOD): Programs that allow participant's compatible smart devices (thermostats, water heaters, batteries, EV chargers) to sign up for the utility's demand response program, typically in exchange for small rebates. Similarly, Bring Your Own Thermostat (BYOT) is used for thermostat only programs.

Behind-the-meter (BTM): Customer-sited distributed power generation. This generation is "behind" because it is on the other side of the utility's electricity meter.

Demand Response (DR): A form of energy conservation that offers incentives to reduce energy, particularly during certain times of day and/or when notified by an event.

Demand Side Management (DSM): Includes both energy efficiency and demand response programs.

Distributed Energy Resource Management Systems (DERMS): Are the software platforms that are used to synchronize and aggregate DERs.

Energy Efficiency (EE): Measures or devices or process improvements that enable a consumer to use less energy to perform the same task.

Front-of-the-meter (FTM): Energy generation and storage systems that are connected to the utility side of the meter. These are generally larger resources (usually 1 to 5 MW range) compared to behind-the-meter (BTM) resources (usually <1 MW), but smaller than utility-scale generation (>10 MW).

Gross/Net Savings: In the context of demand-side management and energy efficiency programs, gross savings represents the total energy reduction from efficiency measures (regardless of if the savings would have occurred anyways). Net savings takes into account free riders and spillover effects to only measure net-new savings that would not have otherwise occurred.

Inverter Based Resources (IBRs): An inverter is a power electronic device that converts direct current (DC) electricity to alternating current (AC) electricity. IBRs resources include modern wind turbines, solar photovoltaic, and battery energy storage resources.

Net Energy Metering (NEM): A metering and billing program that allows customers who generate electricity from renewable energy generation assets to receive credit for excess power they export to the grid.

Time-of-Use (TOU): A utility pricing plan/rate structure where the cost of electricity changes depending on the time of day, with higher rates during peak hours and lower rates during off-peak hours.

Vehicle-to-Grid (V2G): Bidirectional charging where vehicles can inject power back to the grid. Related terms to V2G include vehicle-to-home (V2H), vehicle-to-building (V2B), and the umbrella term of vehicle-to-everything (V2X).

Appendix B. Modeling Assumptions

Parameter	Value	Source/Note
General Input Assumptions		
Discount Rate	7.0%	Dominion 2024 Rate Case - Filing Schedule 3
Inflation Rate	3%	CEG Estimate[130]
Installed Reserve Margin	19.1%	PJM Installed Reserve Margin[131]
Fossil Fuel Resource Assumptions		
Gas Commodity Costs ($/MMBTU)	$3.57	EIA Annual Energy Outlook 2025 - 2028 Delivered price to Electric Power sector
Gas Emissions (kg/MMBtu)	52.91	EIA Carbon Dioxide Emissions Coefficients
Firm Fuel Transportation Costs ($/kW-yr)	$21.85	Public Service Company of Colorado and Louisville Gas and Electric[132, 133]
Gas Unit Asset Life (years)	30	CEG Estimate
Heat Rate - CT (MMBtu/MWh)	10.19	Dominion 2024 IRP, Appendix 3B-5 - Average CT Brownfield 4X
Heat Rate - CC (MMBtu/MWh)	6.25	Dominion 2024 IRP, Appendix 3B-5 - Average CC 2x1
Capital Costs – CT ($/kW)	$1,702	Dominion CPCN filing for the Chesterfield Energy Reliability Center[134]
Capital Costs – CC ($/kW)	$2,460	Dominion Energy South Carolina 2024 IRP Update[135]
Fixed O&M – CT ($/kW-yr)	$28.98	NREL ATB[136]
Fixed O&M – CC ($/kW-yr)	$44.05	NREL ATB[137]
Variable O&M – CT ($/kW-yr)	$8.29	NREL ATB[138]

[130] Unless otherwise stated, all currency inputs are converted to 2028-year dollars using the inflation rate.
[131] Monitoring Analytics, "2025 Quarterly State of the Market Report for PJM" (November 13, 2025), Section 5, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025.shtml.
[132] Firm fuel cost of $21/kW-yr for CTs. Application of Public Service Company of Colorado for Approval of its 2024 Just Transition Solicitation, Proceeding No. 24A-0442E (Colorado Public Utilities Commission, October 15, 2024).
[133] Firm gas cost of $19/kW-yr. Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates, Case No. 2025-00045 (Kentucky Public Service Commission, February 28, 2025), https://psc.ky.gov/Case/ViewCaseFilings/2025-00045.
[134] Direct Testimony of Jeffrey G. Miscikowski, Virginia SCC Case No. PUR-2025-00037 (March 3, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/845p01!.PDF.
[135] Dominion Energy, "*DESC IRP Update Process and Schedule, Supply-Side Inputs Candidate Resource Options*", DESC IRP Stakeholder Advisory Group Session XVI, (November 12, 2024), https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/MeetingMaterials/DESC_IRP_Stakeholder_Advisory_Group_Session_XVI.pdf.
[136] See National Renewable Energy Laboratory 2024 Annual Technology Baseline ("NREL ATB"), NG Combustion Turbine (F-frame), Moderate Scenario, 2028 in-service year, https://atb.nrel.gov/electricity/2024b/fossil_energy_technologies.
[137] NREL ATB, NG 1-on-1 Combined Cycle (H-frame), Moderate Scenario, 2028 in-service year.
[138] NREL ATB, NG Combustion Turbine (F-frame), Moderate Scenario, 2028 in-service year.

Parameter	Value	Source/Note
Variable O&M – CC ($/kW-yr)	$2.93	NREL ATB[139]
ELCC – CT	61%	PJM ELCC Class Ratings for the 2027/2028 Base Residual Auction
ELCC – CC	74%	PJM ELCC Class Ratings for the 2027/2028 Base Residual Auction
Capacity Factor – CT	5%	Dominion 2024 IRP Appendix 3B-4[140]
Capacity Factor – CC	79%	Dominion 2024 IRP Appendix 3B-4[141]
Emissions Rate – PM2.5 – CT (kg/MWh)	0.030	S&P Global Market Intelligence[142]
Emissions Rate – PM2.5 – CC (kg/MWh)	0.066	S&P Global Market Intelligence
Emissions Rate – SO2 – CT (kg/MWh)	0.002	S&P Global Market Intelligence
Emissions Rate – SO2 – CC (kg/MWh)	0.002	S&P Global Market Intelligence
Emissions Rate – NOx – CT (kg/MWh)	0.038	S&P Global Market Intelligence
Emissions Rate – NOx – CC (kg/MWh)	0.096	S&P Global Market Intelligence
Transmission and Distribution System Assumptions		
Asset Life (years)	50	CEG Estimate
O&M Expense	3%	MISO Transmission Expansion Plan[143]
Energy Losses	6.25%	EIA Virginia Electricity Profile 2024[144]
Embedded Cost – Transmission ($/kW)	$772.75	Dominion FERC Form 1[145]
Embedded Cost – Distribution ($/kW)	$622.42	Dominion FERC Form 1[146]
DERs Assumptions		
Asset Life – Solar PV	30	CEG Estimate

[139] NREL ATB, NG 1-on-1 Combined Cycle (H-frame), Moderate Scenario, 2028 in-service year.
[140] Capacity factors filtered for new Gas Peaking plants (Ladysmith and Remington units), average in 2027-2029.
[141] Capacity factors filtered for Gas Baseload generators, average 2027-2029.
[142] Generation weighted average emissions rate of CT generators in NY. S&P Global Market Intelligence, Capital IQ (subscription), https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=127417.
[143] Annual expense as a fraction of capital cost. Midcontinent Independent System Operator, "Transmission Expansion Plan 2022, Transmission Cost Estimation Guide", (April 2022), Table 5.1 (Average Expense Factors), https://cdn.misoenergy.org/20220208%20PSC%20Item%2005c%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP22_Draft622733.pdf.
[144] Energy Information Administration, Virginia Electricity Profile 2024, Table 10, https://www.eia.gov/electricity/state/virginia/
[145] Sum of FERC accounts 352-358, divided by peak demand, averaged between 2019-2024.
[146] Sum of FERC accounts 362 and 364-367, divided by peak demand, averaged between 2019-2024.

Parameter	Value	Source/Note
Capital Costs – Commercial Solar ($/kW)	$1,847	NREL ATB[147]
Capital Costs – Residential Solar ($/kW)	$2,636	NREL ATB
Fixed O&M – Commercial Solar ($/kW-yr)	$19.71	NREL ATB
Fixed O&M – Residential Solar ($/kW-yr)	$30.14	NREL ATB
ELCC – Commercial Solar	7%	PJM ELCC Class Ratings for the 2027/2028 Base Residual Auction
ELCC – Residential Solar	7%	PJM ELCC Class Ratings for the 2027/2028 Base Residual Auction
Capacity Factor – Commercial Solar	18.88%	NREL PVWatts[148]
Capacity Factor – Residential Solar	18.45%	NREL PVWatts[149]
Capacity Factor – Battery	8.33%	2-hour daily dispatch
Battery Round-trip efficiency	0.85	CEG Estimate
NEM Program Costs	$0.122	Dominion Residential Tariff Rate (Schedule 1)[150]
VPP Assumptions		
VPP Total Program Costs – Demand Response ($/kW-yr)	$77.37	Dominion[151] and Appalachian Power DSM EM&V Reports[152]
VPP Total Program Costs – Batteries behind-the-meter ($/kW-yr)	$321.00	Public Service Company of Colorado VPP Program
VPP Total Program Costs – Electric Vehicle V2X ($/kW-yr)	$427.56	Participant incentive of 75% of resource benefits[153]

[147] NREL ATB, Commercial (Class 5 default), Moderate Scenario, 2028 in-service year, https://atb.nrel.gov/electricity/2024/commercial_pv.

[148] PVWatts, *Fixed ground mount, 1.2 DC-AC ratio PV system*, https://pvwatts.nrel.gov/pvwatts.php.

[149] PVWatts, *Fixed, roof mounted, 1.2 DC-AC ratio PV system*, https://pvwatts.nrel.gov/pvwatts.php.

[150] Dominion Energy, *Dominion Residential Tariff Schedule 1 generation, distribution, and transmission component costs, as well as costs for fuel (rider A), energy efficiency (rider C4A), distribution (rider DIST), Generation (rider GEN)*, https://www.dominionenergy.com/virginia/rates-and-tariffs/residential-rates.

[151] Total Demand Response program expenses divided by summer net peak reduction. DNV Energy Insights USA Inc. *Evaluation, Measurement, and Verification Report Developed for Virginia Electric and Power Company*, Virginia State Corporation Commission Case No. PUR-2023-00217, (June 15, 2025), https://www.dominionenergy.com/-/media/content/save-energy/x-pdfs/global/key-documents/emv-report-for-program.pdf.

[152] Virginia State Corporation Commission, *Combined Annual Report on Energy Efficiency Programs and the Feasibility of Achieving Energy Efficiency Goals* (October 1, 2024), https://www.scc.virginia.gov/media/sccvirginiagov-home/regulated-industries/utility-regulation/responsibilities/2024-1001-combined-energy-efficiency-annual-report.pdf.

[153] Based on a participant incentive of 75% of quantified avoided capacity, energy, and emissions benefits per kW of reduced demand ($490/kW-yr), with an additional 7% administrative costs.

Parameter	Value	Source/Note
VPP Total Program Costs – BYOD Tech Agnostic Aggregator ($/kW-yr)	$142.19	Dominion Bring-Your-Own-Device Aggregator Access Pilot VPP Program Proposal[154]
VPP Administrative Costs – Demand Response ($/kW-yr)	$5.99	Dominion and Appalachian Power DSM EM&V Reports
VPP Administrative Costs – Batteries behind-the-meter ($/kW-yr)	$21.00	Public Service Company of Colorado VPP Program[155]
VPP Administrative Costs – Electric Vehicle V2X ($/kW-yr)	$27.97	Public Service Company of Colorado VPP Program
VPP Total Program Costs – BYOD Tech Agnostic Aggregator ($/kW-yr)	$28.20	Dominion Bring-Your-Own-Device Aggregator Access Pilot VPP Program Proposal[156]
ELCC – VPP Demand Response Resources	92%	PJM ELCC Class Ratings for the 2027/2028 Base Residual Auction
Energy Efficiency Assumptions		
Total EE Program Costs ($/kWh)	$0.038	VA SCC Combined EE Reports[157]
EE Program Administrative Costs ($/kWh)	$0.0029	VA SCC Combined EE Reports
Capacity Factor – EE	65.2%	VA SCC Combined EE Reports[158]
Emissions Assumptions		
Social Cost of PM2.5 ($/ton)	$278,225	EPA COBRA[159]
Social Cost of SO2 ($/ton)	$85,786	EPA COBRA
Social Cost of NOx ($/ton)	$125,781	EPA COBRA
Social cost of carbon ($/Tonne)	$93.01	Nature[160]

[154] Proposed Summer Coincident Demand Peak Reduction divided by total program costs. Direct Testimony of Rachel L. Hagerman, Schedule 2, Virginia SCC Case No. PUR-2025-00210 (May 21, 2024), https://www.scc.virginia.gov/docketsearch/DOCS/7zht01!.PDF.

[155] Public Service Company of Colorado's Aggregator Virtual Power Plant Program contained an administrative budget that averaged 7% of total program costs, after the first year. Direct Testimony and Attachments of Jack W. Ihle, Colorado PUC Proceeding No. 25A-0061E (Colorado Public Utilities Commission, January 31, 2025).

[156] Proposed Summer Coincident Demand Peak Reduction divided by total program costs. Hagerman Testimony, Schedule 2.

[157] Program expenditures divided by lifetime net energy savings for Dominion Energy and Appalachian Power. Virginia SCC, *Combined Annual Report on Energy Efficiency Programs and the Feasibility of Achieving Energy Efficiency Goals* (October 1, 2024), 15, https://www.scc.virginia.gov/media/sccvirginiagov-home/regulated-industries/utility-regulation/responsibilities/2024-1001-combined-energy-efficiency-annual-report.pdf.

[158] Program annual net energy savings divided by total summer net peak reduction (MW) for Dominion Energy and Appalachian Power.

[159] Environmental Protection Agency, *CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA)*, Input Scenario: Virginia, Fuel Combustion: Electric Utility, Natural Gas, https://www.epa.gov/cobra.

[160] Rennert, Kevin et al. "Comprehensive Evidence Implies a Higher Social Cost of CO_2", *Nature* 610, no. 7933 (September 1, 2022): 687–92. https://doi.org/10.1038/s41586-022-05224-9.

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Beginning in 2007 with a student-inspired effort to install solar panels, a parent organized the first neighborhood solar co-op to make clean energy more affordable and accessible. This successful grassroots initiative evolved into a national organization, Solar United Neighbors, dedicated to empowering communities to take control of their energy systems. Today, SUN's mission is to help people go solar, join together, and fight for their energy rights.

More information about SUN is available at: https://solarunitedneighbors.org/

Disclaimer

This report was prepared by Current Energy Group on behalf of Solar United Neighbors (SUN). It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the author using currently available information and does not necessarily reflect those of any other entity associated with this work.

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