

Distributed Energy Resources Task Force – Interim Report

*For the Governor, the General Assembly, and the State Corporation
Commission*

Established pursuant to House Bill 285 / Senate Bill 223
(2026 Acts of Assembly, Chapters 1042/997)

DRAFT — FOR TASK FORCE DISCUSSION PURPOSES ONLY

Table of Contents

1. Executive Summary & Key Findings	4
2. Introduction	14
2.1 Statutory Mandate and Objectives of the Task Force	14
2.2 Overview of Task Force Approach and Process	14
Scope of Task Force Efforts	Error! Bookmark not defined.
2.3 Purpose and Contents of this Report.....	15
2.4 Definitions	15
2.4.1 DERs vs. VPPs	Error! Bookmark not defined.
2.4.2 Definitions of Related Terms	16
3. Vision for DERs and VPPs in the Commonwealth	18
3.1 Key Benefits of DERs and VPPs	18
3.2 How DERs and VPPs can address Virginia’s evolving energy needs	21
3.3 The Task Force’s Vision for DERs in Virginia	22
Near-Term and Long-Term Trajectory	23
4. Current State of DERs in Virginia	25
4.1 Legislative and Regulatory Foundations	25
4.2 Virginia’s DER Deployment Current State	27
<i>Virginia’s Historical DER Deployment</i>	28
<i>How Virginia Stacks Up Against Peers</i>	30
4.4 Conclusion	30
5. Task Force Findings, Recommendations, and Path Forward	32
5.1 Key Findings & Recommendations	33
Cross-Cutting.....	33
Recommendation 1: Pursue an Integrated, Systems-based DER Strategy with Necessary State Implementation Capacity.....	33
Recommendation 2: Leverage Data Centers to Drive DER & VPP Deployment	35
DER Market Participation (VPP Aggregation)	38
Recommendation 3: Establish VPP-Enabling Policies	38
Recommendation 4: Develop Expanded DER and VPP Compensation Models	41
Recommendation 5: Implement Minimum Changes to Enable VPP Participation in PJM Markets via FERC Order 2222	43
Recommendation 6: Align Utility Incentives and Planning Structures with DER Deployment.....	45
DER Adoption	47

Recommendation 7: Reduce Upfront Cost Barriers to DER Adoption	
Recommendation 8: Support Schools & Public Facility DER Adoption	48
Recommendation 9: Modernize DER Interconnection Policies	50
Recommendation 10: Remove Barriers to Electrification	Error! Bookmark not defined.
Recommendation 11: Enhance Customer Education and Outreach	55
5.2 VPP Enabling Policy Prioritization and Regulatory Roadmap	57
5.3 FERC Order 2222 DER Aggregation Roadmap	64
5.4 Integrated DER Action Plan Summary	55
Appendix	72
A. Overview of Task Force Members.....	72
B. Summary of Stakeholder Input and Process.....	72
C. Relevant Enabling Virginia Legislation	77
D. EPDI VPP Policy Framework.....	79
E. Example DER Interconnection Implementation Changes	Error! Bookmark not defined.
F. Summary of DER Modeling Outputs	84

1. Executive Summary & Key Findings

DER Task Force Mandate and Report Structure

Virginia is entering a period of unprecedented electricity demand growth. However, new generation and transmission projects take years to permit and build, interconnection queues are lengthening, and ratepayers are experiencing increasing electricity costs. Distributed energy resources (DERs) such as rooftop solar, batteries, smart thermostats, and managed EV charging are key tools for addressing these challenges by adding grid capacity faster and more cheaply than new generation or transmission, easing costs for customers, and substantially advancing clean energy goals. In recognition of the deliberate policy choices that need to be undertaken to advance greater DER deployment at scale, the General Assembly passed House Bill (HB) 285 and Senate Bill (SB) 223 during the 2026 Regular Session of the General Assembly (2026 Acts of Assembly, Chapters 1042 and 997). HB 285 / SB 223 established a Virginia DER Task Force to:

1. Develop a comprehensive strategy to advance energy affordability and the Commonwealth's transition toward integrated distributed energy resource markets.
2. Support the Commonwealth's compliance with Federal Energy Regulatory Commission (FERC) Order 2222.

Following this mandate, the DER Task Force, supported by executive branch staff and consulting support from Deloitte and the Energy Policy Design Institute (EPDI), conducted research on the current state of DERs in the Commonwealth; held four public Task Force meetings to discuss comparative DER policy models and align on emerging recommendation themes; elicited feedback in 1:1 interviews from diverse perspectives, including utilities, local government representatives, industry stakeholders, and the public; identified tailored strategies addressing DER deployment challenges in Virginia; and drafted, wrote, and approved DER recommendations. This report is the culmination of these efforts and represents the Virginia DER Task Force's vision, findings, and 11 recommendations and is organized as follows:

- **Section 2** lays out the statutory context and objectives of the Task Force and details Task Force analysis, research, and report development processes.
- **Section 3** details The Task Force's vision for DERs and VPPs in the Commonwealth and describes their benefits.
- **Section 4** describes the current state of DER deployment in Virginia and the legislative and regulatory foundations underpinning Task Force efforts.
- **Section 5** presents the Task Force's findings recommendations, organized around the mutually reinforcing framework of **DER Adoption** and **DER Market Participation**; this section also includes the FERC Order 2222 DER aggregation implementation roadmap required by the Task Force's authorizing legislation.

Current Key Trends and Opportunities for DERs in Virginia

Virginia's energy system faces a set of related priorities that make near-term action on DERs a priority for the Commonwealth, including:

- **Expanding the grid to support a rapid growth in electricity demand:** Commercial electricity sales in Virginia rose by nearly 30 million megawatt-hours (MWh) between 2019 and 2025, a faster increase than in every state except Texas.¹ PJM projects that Dominion's load zone will see the largest absolute increase in summer peak demand of any zone in its 13-state footprint through 2030, growing at an average of 5.4% per year.²
- **Reducing rising costs for Virginia ratepayers:** Although inflation-adjusted electricity prices in Virginia actually declined between 2019 and 2024, that trend has reversed as demand growth outpaces supply. As reported in the 2026 Virginia Energy Plan, under status quo utility planning assumptions, Dominion Energy and Appalachian Power project residential electricity prices could rise approximately 60% and 17%, respectively, over the next decade.³
- **Advancing clean energy deployment:** Under the Virginia Clean Economy Act (VCEA), Dominion and Appalachian Power must supply 100% carbon-free electricity by 2045 and 2050, respectively,⁴ a transition that must occur even as electricity demand from data centers and electrification continue to climb.

DERs can play a unique role in addressing these evolving energy priorities in Virginia by:

- **Deploying cost effective capacity more quickly:** Aggregated DERs can help Virginia interconnect new load faster and at lower cost than relying solely on new generation, transmission, and distribution buildout.
- **Mitigating rising costs:** Paying DERs for grid services allows the Commonwealth to make fuller use of existing infrastructure, deferring or avoiding costlier new investment and directly addressing the ratepayer cost pressure described above. The Brattle Group, an economic consulting firm, estimates \$110-170 billion in national savings over the next decade;⁵ a 2026 study commissioned by Solar United Neighbors estimates approximately \$288.2 million in annual net savings for Virginia by 2028 with an expanded portfolio of DERs.⁶
- **Supporting Virginia's clean energy goals:** Rewarding DERs for the grid value they provide drives customer funded investment in solar, storage, and EV-based resources, which are dispatchable, clean grid assets that directly support the Commonwealth's carbon-free electricity objectives. DERs also often leverage private capital to add this new capacity and advance clean energy deployment, helping attract more diverse sources of capital beyond the traditional rate base.

¹ U.S. Energy Information Administration, "Commercial electricity sales have soared in Virginia, driven by data centers," Today in Energy, May 5, 2026, <https://www.eia.gov/todayinenergy/detail.php?id=67664>.

² U.S. Energy Information Administration, "Commercial electricity sales have soared in Virginia, driven by data centers," Today in Energy, May 5, 2026, citing PJM Interconnection, 2026 Long-Term Load Forecast Report, Dominion Virginia Power zone, Tables B1–B2.

³ Virginia Energy (Commonwealth of Virginia, Department of Energy), 2026 *Virginia Energy Plan, Executive Brief* (Richmond, VA, October 2026), <https://energy.virginia.gov/public/documents/Virginia%20Energy%20Plan/Energy%20Plan%20Executive%20Brief%201.pdf>. The Executive Brief's inflation-adjusted price-decline finding draws on Lawrence Berkeley National Laboratory analysis; the 60%/17% figures reflect utility integrated-resource-plan projections as cited in the Executive Brief under status quo conditions.

⁴ Code of Virginia § 56-585.5, as amended by 2020 Acts of Assembly, Chapter 1193 (HB 1526) / Chapter 1194 (SB 851) (Virginia Clean Economy Act).

⁵ Ryan Hledik, Long Lam, and Kate Peters, The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability (The Brattle Group, prepared for GridLab and Utilize Coalition, March 2026).

⁶ "Value of Distributed Energy Resources in Virginia" (2026), commissioned by Solar United Neighbors.

These findings align with the 2026 Virginia Energy Plan that similarly identifies DERs and demand flexibility (which could be achieved through DERs and VPPs) as critical parts of Virginia’s energy future. In several of its power sector forecast scenarios, the Energy Plan identifies a target of at least 10 GW of DER capacity by 2045 and 10% demand flexibility from data center load.⁷

Summary of Task Force Vision and Key Findings

To guide its research objectives and recommendations, the Task Force laid out a vision statement in its initial weeks. Actions recommended in this report aim to build:

A Virginia energy system where all types of DERs are valued as integral, scalable grid resources—enabled to deliver and be fairly compensated for providing cost-effective grid services to meet Virginia's energy needs (affordable, reliable, clean, safe, secure, and resilient power) through market and regulatory designs that build on the Commonwealth's existing foundations for DER deployment and evolve with technology, markets, and system innovations.

Achieving this vision requires an understanding of where DERs and DER adoption is today in the Commonwealth. To date, Virginia has seen growing adoption of distributed solar PV, though net-metered solar capacity trails similarly sized peer states;⁸ based on Deloitte's internal modeled analysis (blending EIA Form EIA-861 net-metering data⁹ with proprietary vendor and Lawrence Berkeley National Laboratory data), Virginia's combined solar, storage, and demand response DER capacity grew at an estimated 48.5% compound annual rate – largely driven by distributed solar – between 2016 and 2024, reaching approximately 858 MW.¹⁰ However, distributed battery adoption has been comparatively modest, and a separate DER adoption modeling analysis from Deloitte finds that additional financial supports (e.g., low cost financing, incentives) may be needed to drive faster small scale residential solar – and particularly battery storage – going forward.

Key findings—and the recommendations they’re related to—from the Task Force include:

- **Transitioning from fragmented programs to an integrated, systems-based strategy:** Virginia has established foundational building blocks across a variety of forums—including net energy metering, shared solar expansions, distributed storage mandates, and initial utility VPP pilots, with many related efforts underway as well (e.g., ongoing DSM dockets, DER interconnection reforms). This various efforts are happening alongside rapidly evolving regional dynamics—such as PJM market reforms and capacity procurement programs that could impact DERs, new data center demand flexibility programs under SB 371, and potential reinstatement of federal *Solar for All* funding—reinforce the urgent need to bridge these initiatives through an integrated statewide approach with durable, resourced capacity to ensure the Commonwealth can identify and fill

⁷ Virginia Energy, et al. Virginia Energy Plan (October 2026).

https://energy.virginia.gov/public/documents/Virginia%20Energy%20Plan/2026_Virginia_Energy_Plan.pdf

⁸ U.S. Energy Information Administration, Form EIA-860, Net Metering dataset (December 2025); population figures per U.S. Census Bureau.

⁹ EIA defines net metering as “Utility tariffs or billing programs that allow certain types of customers to reduce the volume of billed electricity supplied by the grid within a defined billing period by taking into account the amount of electricity that the customer sold back to the grid during times when self-generation (typically powered by a renewable energy source) exceeded consumption.”

¹⁰ Deloitte, “Virginia DER Baseline — Solar PV + BESS,” internal analysis, August 21, 2026, based on U.S. Energy Information Administration, Form EIA-861, Net Metering file; proprietary BTM storage vendor data; Lawrence Berkeley National Laboratory, Tracking the Sun; and U.S. DOE Alternative Fuels Data Center. Modeled estimate, not a direct government census.

market or regulatory gaps, capture cross-program learnings, and dynamically adapt to industry innovation. *[Recommendation 1]*

- **Leveraging data center growth to fund DER deployment:** Data centers represent both the primary driver of near-term demand growth and a potential funding source for DER and VPP deployment. Several ongoing efforts—including implementation of SB 371 that could include DER-funded pathways as a demand flexibility mechanism, implementation of Virginia’s new Data Center Accountability Framework and Executive Order 22 (2026), emerging data center-DER bilateral contract models, and ongoing PJM programs and market reforms related to large load that have implications for DERs and VPPs—present several near-term opportunities that could create enduring pathways for data center funded DER deployment and aggregation initiatives in the Commonwealth if implemented effectively. *[Recommendation 2]*
- **Establishing a common, statewide VPP-enabling framework:** While Virginia has established utility-run VPP efforts (including Dominion and APCo VPP pilots and enabling coops to set up VPP programs), the Commonwealth has not yet defined foundational rules required for permanent, scalable VPPs at both the retail level and in PJM wholesale markets (including alignment with FERC Order 2222 related policies). Rather than deferring market rules until pilots conclude in 2028–2029, the state can establish a "minimum viable" policy floor now—covering key topics like customer data access, DER registration, operational coordination, and dual-participation rules among others—to support standardization and scalability across utilities and various VPP programs. Defining these standard rules in parallel with ongoing pilots prevents fragmented, utility-by-utility silos and provides the regulatory certainty needed to unlock immediate, high-value models like data center-funded contracted capacity. Pilot findings can then iteratively refine, rather than delay, a unified statewide framework. Additionally, this can harmonize Virginia policies with PJM rules through FERC Order 2222, as directed by the DER Task Force statute. *[Recommendations 3, 5]*
- **Compensating DERs for grid services:** Separately from NEM, compensating DERs for specific grid services they provide including locational value and energy, capacity, demand-reduction, and ancillary services through a value-stacking framework—that supports both retail and wholesale participation—can help support deployment of cost-effective DERs at scale. Several other states (e.g., New York, Maryland, Massachusetts) have or are moving towards establishing more comprehensive VPP value-stacking tariff models. *[Recommendation 4]*
- **Aligning utility incentives and planning & operations with DER deployment:** Virginia has several reforms underway—including ongoing IRP reforms, performance-based ratemaking working group, grid utilization metrics development, transition towards Jurisdictional Specific Test (JST) for evaluating cost-effectiveness of utility VPP programs—that could support better integration of lower-cost DER and VPP alternatives if implemented effectively. *[Recommendation 6]*
- **Reducing cost barriers for residential and commercial DER adoption:** Raising the net-metering cap, developing a NEM-stackable incentive framework (including for priority deployment opportunities like agrivoltaics and brownfields), streamlining residential solar permitting, creating flexible service-connection pathways for new distributed load, and pursuing other strategies that

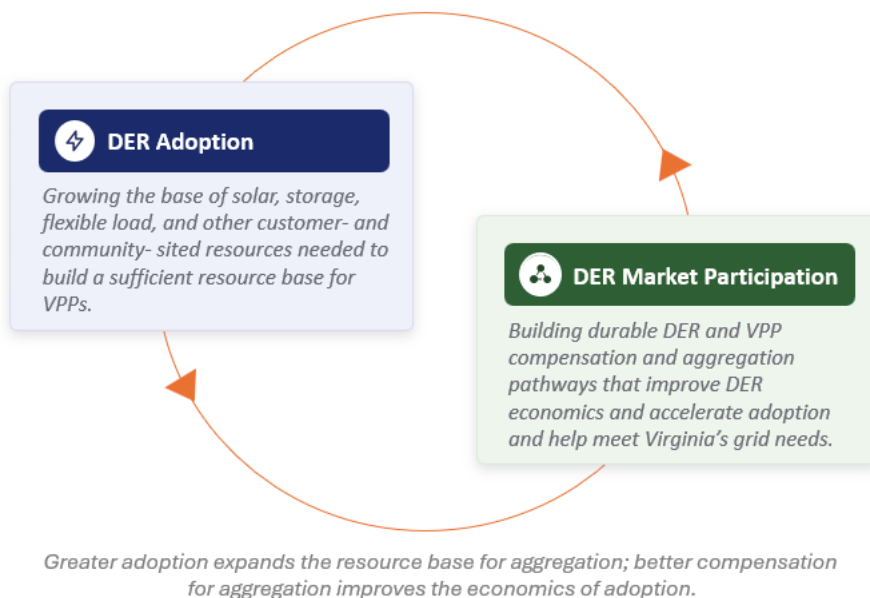
reduce costs (e.g., bulk procurements, low-cost financing) can each reduce the upfront cost and time barriers that currently limit DER adoption. *[Recommendations 7, 10]*

- **Unlocking DER adoption at schools and public facilities:** Schools and other public facilities represent a significant opportunity to increase DER adoption but face distinct barriers including interconnection timelines, financing, technical capacity, and procurement complexity that could be directly addressed with a dedicated program with streamlined interconnection for smaller systems, model procurement tools, direct technical assistance, and public funding to support resilience hubs and microgrids. *[Recommendation 8]*
- **Building consumer trust through education and protection:** Scaling DER deployment could be strengthened through a coordinated, statewide consumer education campaign, paired with consumer protection safeguards and vendor accountability, so customers and leaders understand the value of DERs, are protected from predatory sales practices, and can make well-informed investment decisions. *[Recommendation 11]*
- **Modernizing Virginia’s outdated interconnection rules:** Virginia’s DER interconnection rules could benefit from a set of targeted interventions to bring into alignment with national best practices as well as structural reforms that could support long-term program clarity and scalability. Currently, Virginia’s base provisions are more than 20 years old, are split across two administrative chapters, and do not account for technologies such as distributed storage. *[Recommendation 9]*

Summary of Recommended Actions

To operationalize recommendations, the Task Force proposes moving from a set of individual programs such as shared solar, standalone storage targets, and demand-flexibility pilots, toward a coordinated, systems-based approach to DER deployment and market participation, informed by ongoing utility VPP pilots and aligned with the compliance timeline for FERC Order 2222, further outlined below.

Recommendations are categorized across a mutually reinforcing framework whereby DER adoption (i.e., more MWs of solar PV, battery storage, flexible load, and energy efficiency measures) forms the essential building blocks for orchestration and market participation through VPP aggregation. Similarly, as permanent VPP programs become available to all ratepayers—informed by ongoing pilots—and fully integrated into retail and wholesale markets and operations to provide and be compensated for needed grid services, these new financial opportunities in turn facilitate DER adoption (See Figure 1 below).

Figure 1: DER Deployment Framework

The table below summarizes the Task Force's 11 recommendations, designed to advance both pillars together, along with the associated actions and owners positioned to lead implementation. A comprehensive list of findings, supporting rationale, and associated actions are provided in Section 5, including an integrated roadmap with timelines of key existing activities and the recommendations below.

Recommendation	Associated Actions	Primary Owner	Timing
Framework Category: Cross-Cutting Initiatives			
1. Pursue an Integrated, Systems-Based DER Strategy with Necessary State Implementation Capacity	a. After TF sunsets, Executive Branch through the VE DER team (if expanded) alongside the CEO to spearhead and coordinate efforts to advance progress towards the state's DER vision; continue to support DER Task Force until sunset.	Executive Branch / Virginia Energy	Ongoing
	b. Allocate resources to support an expanded Virginia Energy (VE) DER team to spearhead implementation of associated recommendations—such as running cross-stakeholder working groups on specific topics; overseeing program development; monitoring, reporting, and administration of this report's recommended actions. This could be done within existing authorities, but optional supportive legislation could further clarify focus and scope.	General Assembly	Near-term (2027 GA and budget)

Recommendation	Associated Actions	Primary Owner	Timing
2. Leverage Data Centers to Drive DER & VPP Deployment	a. Review Dominion and APCo's January 2027 submission on large load demand flexibility models per SB 371 to evaluate alignment with goals of establishing pathways for data-center funded DER deployments with meaningful community benefits (both system-wide capacity and localized models). Monitor 2027 and 2028 cooperative submissions.	DER Task Force / VA Energy*	Near-term (2027 Q1); ongoing as needed
	b. Monitor and engage in near-term PJM activities to support data center contract and market models that advance statewide DER goals – specifically looking at near-term pathways to support Peak Shaving Adjustment mechanisms in the Reliability Backstop Procurement to reduce market costs for Virginia and advance DER deployment.	CEO / Virginia Energy / DER Task Force	Immediate (2026 Q4-mid-2027); ongoing as needed
	c. Under the Data Center Accountability Framework and EO22 directives, continue to identify and support pathways for data center-funded DER and demand flexibility initiatives.	Chief Energy Officer	Immediate (2026 Q4 and ongoing)
Framework Category: DER Market Participation			
3. Establish VPP-Enabling Policies	a. Begin establishing common statewide frameworks for key VPP enabling policies, with focus on policies related to data-center pathways given near-term, time-sensitive activities. This could specifically include customer data access policies, customer enrollment protection, dual participation (including NEM + storage pathways discussed under Rec 7), dispatch override, grid services mechanisms (as part of SB 371), or other topics relevant to SB 371 or ongoing PJM DER opportunities. Include additional recommendations in DER TF final July 2027 Implementation Report or to request SCC to scope into proceedings as relevant (e.g., SB 371 proceeding, "DER Umbrella Docket").	VA Energy* / CEO / DER TF sub-working groups as needed <i>May depend on staff / contract resourcing</i>	Immediate (2026 Q4 – 2027 Q2); ongoing as needed
	b. Scope priority VPP enabling policies into existing dockets where applicable (e.g., DSM, Demand Flexibility). Open a DER Umbrella Docket for regulatory changes that do not clearly belong to an existing docket to clarify policies and support ongoing programs. See detail in 5.1.	SCC (under GA direction if needed)	Near-term (Could open docket by Feb 1, 2027 per SB 223 to align with FERC timelines); ongoing

Recommendation	Associated Actions	Primary Owner	Timing
4. Develop Expanded DER and VPP Compensation Models	a. Coordinate with the SCC, legislature, and utilities to develop a value-stacking compensation framework (energy, capacity, demand-reduction, and locational-relief components), allowing storage paired with solar and storage-only DERs to qualify.	Virginia Energy	Near / medium term (Initiate in 2027)
5. Implement Minimum Changes to Enable VPP Participation in PJM Markets via FERC Order 2222	a. Establish the minimum statewide procedures necessary for aggregators to understand distribution-system participation rules ahead of PJM's 2027 market processes in line with SB 223 direction—either via DER Umbrella Docket or FERC Order 2222 specific docket to address relevant issues.	SCC	Near-term (Could open docket by Feb 1, 2027 per SB 223)
	b. Continue engaging with PJM to advocate for solutions that ensure market reforms under development are consistent with state DER and VPP goals.	CEO / Virginia Energy	Ongoing
6. Align Utility Incentives and Planning Structures with DER Deployment	a. Monitor implementation of PBR working group (HB 903/SB 251), grid utilization metrics (HB 434/SB 621), income and age qualified solar, storage, EE (HB 1062/SB 327), Pay as You Save (PAYS) developments (HB 1062/SB 327), and IRP reforms (HB 429/SB 249) to ensure resulting proceedings and frameworks support DER adoption and market integration goals.	Virginia Energy* / CEO / DER Task Force	Near-term (2026-2027)
Framework Category: DER Adoption			
7. Reduce Upfront Cost Barriers through NEM-Stackable Incentives and Reward Locational Attributes	a. Provide state funding and expand policies that encourage projects to be developed on previously disturbed lands (e.g., agrivoltaics, brownfields, former mine land).	Virginia Energy* / General Assembly	Near-term (2027 GA)
	b. Consider expanding lower-cost financing options by expanding VCEIB's budget to offer reduced-interest loans, credit enhancements, or other financing tools tailored to residential- and small-commercial-scale solar and storage.	Virginia Energy* / General Assembly	Near / Medium Term
	c. Facilitate bulk procurement models (e.g., Switch Together program) to promote lower-cost solar group-purchasing throughout the state.	CEO / Virginia Energy	Near-term / Ongoing
	d. Evaluate other state actions to support cost reductions, such as income-limited state tax-credits.	General Assembly	Medium/long-term

Recommendation	Associated Actions	Primary Owner	Timing
	e. Raise net metering project size from 500 kw to 3 MW on agricultural lands to support viability of projects like agrivoltaics.	General Assembly	Near term (2027 GA)
	f. Raise the 6%-of-peak-demand net-metering cap before deployment approaches the cap.	General Assembly	Medium/long-term
8. Support Schools & Public Facility DER Adoption	a. Establish a dedicated school and public-facility DER adoption program, including streamlined interconnection for projects ≤1 MW, cooperative-procurement pathways, and additional grants for microgrid/resilience-hub capabilities.	General Assembly	Near Term (2027 GA)
	b. Develop materials and conduct outreach tailored to local governments and public entities, including model PPA templates, FAQs, and training sessions, and create a recognition system for DER-friendly ordinances.	Virginia Energy*	Medium/Long-term
9. Modernize DER Interconnection Policies	a. Implement targeted, near-term reforms to align specific Virginia interconnection rules with the IREC Model Interconnection Procedures (including harmonizing discrepancies across Chapters, implementing regular review cycles, etc.).	SCC (with GA as needed)	Near-term (2027 GA+)
	b. Consolidate and streamline rules currently spread across Chapters 314 and 315 to establish a unified interconnection framework for all state-jurisdictional DERs.	SCC (with GA as needed)	Medium/Long-term (2027-28)
	c. Implement Flexible Interconnection Pathways for Energy Storage Resources through existing DER Interconnection proceedings.	SCC (with GA as needed)	Near / Medium term (2027)
	d. Establish clear pathways for Meter Socket Adapters to support energy storage interconnection through existing DER interconnection proceedings.	SCC (with GA as needed)	Near / Medium term (2027)
10. Remove Barriers to Electrification	a. Explore options to establish flexible service-connection pathways that allow new small-scale loads and generation (e.g., EVs, home storage) to connect without a full infrastructure upgrade (e.g., via UL-listed power control systems).	Virginia Energy*	Medium/ Long Term
	b. Explore cost-effective alternatives to traditional service upgrades, including need for public funding to help customers adopt technology that can make a service upgrade unnecessary.	Virginia Energy*	Medium/ Long Term

Recommendation	Associated Actions	Primary Owner	Timing
11. Enhance Customer Education and Outreach	a. Develop clear, accessible DER/VPP communications tools and outreach campaigns building on VEConnect.	Virginia Energy	Ongoing
	b. Support consumer protection guidelines and vendor registration frameworks.	Virginia Energy	Ongoing

**denotes if Virginia Energy would require additional resources to implement the action*

Conclusion

Achieving Virginia's DER and VPP vision will require sustained coordination between the Governor's Office, General Assembly, State Corporation Commission, utilities, and stakeholders across the Commonwealth. While this vision will require significant coordination and effort, the opportunity to harness the benefits of DERs and VPPs for the benefit of Virginians is immense. The Virginia Energy Plan sets out a target of 10 GW of DERs by 2045 and 10% data-center demand flexibility, which this report lays out a foundation to make significant near-term progress towards that target. Further, the recommendations in this report are designed to be mutually reinforcing: progress on DER adoption strengthens the case for market participation, and a clearer path to DER compensation improves the economics of adoption. Taken together, they position Virginia to meet near-term load growth, mitigate rising energy costs, and advance the Commonwealth's clean energy goals while building the institutional capacity to keep pace as technology, markets, and federal requirements continue to evolve.

2. Introduction

2.1 Statutory Mandate and Objectives of the Task Force

The Virginia Distributed Energy Resources Task Force was established by House Bill (HB) 285 and Senate Bill (SB) 223 and enacted during the 2026 Regular Session of the General Assembly (2026 Acts of Assembly, Chapters 1042 and 997). HB 285 / SB 223 established the Task Force as an executive branch-level advisory commission charged with:

1. Developing a comprehensive strategy to advance energy affordability and the Commonwealth's transition toward integrated distributed energy resource market.
2. Supporting the Commonwealth's compliance with Federal Energy Regulatory Commission (FERC) Order 2222.

In pursuit of these objectives, the authorizing legislation directs the Task Force to review existing laws and practices affecting DER deployment and market access; make recommendations to the State Corporation Commission (SCC) on interconnection standards (IEEE 1547-2018, UL 1741), FERC Order 2222 harmonization, and policies to advance microgrids, resiliency hubs, and VPPs; and convene a participative stakeholder planning process. By statute, the Task Force's final report must include legislative and regulatory recommendations, an explicit recommendation on whether to establish a permanent distributed energy resource council, and a FERC Order 2222 aggregation roadmap designed to take effect by February 1, 2027. The enabling legislation includes a sunset date of July 1, 2027.¹¹

The Task Force is chaired by Chief Energy Officer Josephus Allmond and comprises 16 members in total, including Lieutenant Governor Ghazala Hashmi, Secretary of Commerce and Trade, two Delegates, one Senator, representatives of state and local government, electric utilities, DER industry participants, large loads, and consumer/environmental advocates (full roster in Appendix A¹²).

2.2 Overview of Task Force Approach and Process

To develop the strategy and recommendations that follow, the Task Force pursued a multi-pronged fact-finding process. The Task Force was supported by staff from the Chief Energy Office and Virginia Department of Energy. Deloitte was engaged to support Task Force research and reporting, and the Energy Policy Design Institute (EPDI) was engaged for insight on designing VPP policies in line with national best practice from EPDI's VPP Convergence Project.

Key sources of input included Task Force member expertise during meetings, follow-up written member input and white papers, and one-on-one member discussions; engagement with the SCC, utilities, and cooperatives; input from national experts (including on interconnection, FERC Order 2222, and VPP policy design); lessons from other states (including direct engagement with New York and Massachusetts); public stakeholder and DER industry input;¹³ and reviewing reports and case studies to identify leading practices already in use elsewhere.

¹¹ Va. H.B. 285 / S.B. 223, *A Bill to establish the Distributed Energy Resources Task Force; reports; sunset. 2026.*

¹² See Appendix A for the full roster of VA DER Task Force members.

¹³ See the DER Task Force Participative Planning Report for additional detail on stakeholder input processes.

The Task Force's review also drew on national guidance written specifically for state policymakers and regulators including a joint primer on aggregated DER compensation from the National Association of Regulatory Utility Commissioners and the National Association of State Energy Officials¹⁴ and the Pew Charitable Trusts' distributed energy policy playbook.¹⁵

2.3 Purpose and Contents of this Report

This report is the culmination of these efforts and represents the Virginia DER Task Force's vision for Virginia, key findings, and 11 recommendations to achieve the Commonwealth's distributed energy goals. The report is organized as follows:

- **Section 1** summarizes the Task Force's key findings, recommendations, actions, and owners for an executive audience in a concise format.
- **Section 2** lays out the statutory context and objectives of the Task Force in depth, and details Task Force analysis, research, and report development processes.
- **Section 3** details the Task Force's vision for DERs and VPPs in the Commonwealth and describes their benefits when implemented at scale.
- **Section 4** describes the current state of DER deployment in Virginia and the legislative and regulatory foundations underpinning the Task Force's efforts.
- **Section 5** presents the Task Force's findings recommendations, organized around the mutually reinforcing framework of **DER Adoption** and **DER Market Participation**. This section also includes the FERC Order 2222 DER aggregation implementation roadmap required by the Task Force's authorizing legislation.

As required by statute, this report is submitted to the Governor's Office, the State Corporation Commission, PJM Interconnection, the Energy Commission of Virginia, and the Chairs of the House Committee on Labor and Commerce and the Senate Committee on Commerce and Labor. More broadly, it is intended to inform the General Assembly, state agencies, utilities, local governments, and other stakeholders as Virginia works to expand affordable, reliable access to distributed energy resources over the coming years.

2.4 Definitions

For purposes of this report, the Task Force grounds its working definitions of "distributed energy resource" and "virtual power plant" in Virginia's existing statutory framework, specifically, the definitions the General Assembly already enacted for the Commonwealth's virtual power plant pilot program. These definitions are supplemented by the broader federal definition that will govern how Virginia DERs interact with PJM's wholesale markets under FERC Order 2222. However, the Task Force acknowledges that terminology and definitions will evolve over time and adapt to changes in technology and policy.

Distributed Energy Resource (DER): Virginia law defines a distributed energy resource as "a resource of up to five megawatts that is located on the customer's premises or is interconnected with the

¹⁴ National Association of Regulatory Utility Commissioners and National Association of State Energy Officials, *Aggregated Distributed Energy Resources in 2024: The Fundamentals* (July 2024), <https://www.naruc.org/core-sectors/energy-resources-and-the-environment/der-integration-compensation/>.

¹⁵ The Pew Charitable Trusts, *Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future* (Apr. 28, 2026), <https://www.pew.org/en/research-and-analysis/reports/2026/04/distributed-energy-can-unleash-the-resilient-affordable-grid-of-the-future>.

distribution system and produces or stores electricity or modifies the timing or amount of a customer's electricity consumption.”¹⁶ The Task Force acknowledges that this definition is narrower than the one that will govern wholesale market participation under FERC Order 2222 (e.g., FERC’s definition includes systems over 5 MW); however, to maintain consistency between the Task Force’s recommended actions and Virginia Law, the Commonwealth’s definition is used in this report.¹⁷

Virtual Power Plant (VPP): Virginia law defines a virtual power plant as “an aggregation of distributed energy resources, enrolled either directly with an electric utility or indirectly through an aggregator, that are operated in coordination to provide one or more grid services,” where “grid service” means “a capacity, energy, or ancillary service that supports grid operations.”¹⁸ This definition is both Virginia's own statutory language and already tied to the specific pilot program (Dominion's 450 MW aggregation, authorized under the same section) that is being used as Virginia's near-term testing ground.¹⁹

2.4.2 Definitions of Related Terms

DER Aggregator: Virginia law defines an “aggregator” (in the VPP pilot context) as “an individual or entity, other than the electric utility, that enrolls customers in the pilot program and coordinates the operation of enrolled energy resources,” and specifies that an aggregator is not thereby considered an electric utility but must be given nondiscriminatory access to the customer and grid data it needs to participate.²⁰ At the federal level, FERC Order 2222 establishes “distributed energy resource aggregator” as a new category of wholesale market participant – an entity that aggregates one or more DERs to participate directly in RTO/ISO markets under one or more participation models FERC requires PJM and other grid operators to design.²¹

Microgrids: The U.S. Department of Energy defines a microgrid as “a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid,” capable of operating either connected to the grid or “islanded” from it during an outage.²² Microgrids are named separately from VPPs in the Task Force's enabling statute and, unlike a VPP, do not require aggregation across multiple customer sites (a single facility or campus can constitute a microgrid on its own).

Community Resilience Hubs: A community resilience hub is generally understood as a community-serving facility such as a library, community center, school, or place of worship that is equipped (often via a microgrid or on-site DER) to remain powered during a grid outage and to serve as a gathering point for residents to charge devices, refrigerate medication, or access emergency information and services.²³ The term originated outside of state or federal government but has since been adopted operationally by FEMA, which funds resilience hub projects through its Building Resilient Infrastructure and Communities

¹⁶ Code of Virginia § 56-585.1:16, *Virtual power plant pilot program* (enacted as HB 2346/SB 1100, “Community Energy Act,” 2025), <https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1:16/>.

¹⁷ Federal Energy Regulatory Commission, “Order No. 2222 Fact Sheet,” <https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet>.

¹⁸ Code of Virginia § 56-585.1:16 (see note 1).

¹⁹ Code of Virginia § 56-585.1:16(B) (450 MW Phase II Utility pilot aggregation) (see note 1); already cited in Sections 3.2 and 3.3 of this report.

²⁰ Code of Virginia § 56-585.1:16 (see note 1), definition of “Aggregator.”

²¹ Federal Energy Regulatory Commission, “Order No. 2222 Explainer: Facilitating Participation in Electricity Markets by Distributed Energy Resources,” <https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy>.

²² U.S. Department of Energy, Office of Electricity, microgrid definition, as reflected in DOE program materials, <https://www.energy.gov/oe/microgrids-rd-mgrd-portfolio-activities>, and NIST Smart Grid Testbed documentation.

²³ Description synthesized from Bloomberg Cities (Johns Hopkins University), “How can municipalities fund resilience hubs?,” <https://bloombergcities.jhu.edu/faqs/how-can-municipalities-fund-resilience-hubs>.

(BRIC) and Hazard Mitigation Grant Programs.²⁴ Community resilience hubs are named alongside microgrids in the Task Force's enabling statute as a technology area within scope.

Front-of-the-Meter (FTM) vs. Behind-the-Meter (BTM): This distinction describes where a resource sits relative to a customer's utility meter, and it is foundational to how DERs are valued and regulated. The U.S. Energy Information Administration describes behind-the-meter distributed generation as “onsite” generation on the customer's side of the meter which includes rooftop solar, on-site batteries, and similar customer-sited resources.²⁵ Front-of-the-meter resources, by contrast, are utility-scale generation and storage connected directly to the distribution or transmission system (such as conventional power plants, utility-scale solar farms, and grid-scale batteries) that deliver power to customers only after it passes through the customer's meter.²⁶ The distinction matters for this report because it is a key distinction between “DER Adoption” (largely BTM) and “DER Market Participation” (which can include both BTM aggregations and FTM resources) framework introduced in Section 3.3.

²⁴ FEMA Hazard Mitigation Assistance program materials (Building Resilient Infrastructure and Communities; Hazard Mitigation Grant Program), as described in source 8 above.

²⁵ U.S. Energy Information Administration, “Distributed Generation and Combined Heat and Power,” https://www.eia.gov/analysis/studies/buildings/dg_storage_chp/.

3. Vision for DERs in the Commonwealth

Virginia’s DER Task Force envisions a **regulatory and market framework where all DERs are valued as integral, scalable grid resources and are enabled to deliver and be fairly compensated for providing cost-effective grid services** to meet Virginia’s energy needs. These market and regulatory designs must both built on the Commonwealth’s existing strategies for DER deployment and be structured to anticipate grid evolution, adapting with technology, markets, and system innovations.

This section provides an overview of DER and VPP benefits and describes how these dynamic resources can be harnessed to mitigate rising energy and infrastructure costs and help meet the Commonwealth’s growing power needs.

3.1 Key Benefits of Aggregated DERs

As cited by the DOE’s *Pathways to Commercial Liftoff: Virtual Power Plants* Report and Pew’s *Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future*, DERs provide meaningful benefits to the broader grid and residents. DERs include customer- and community-sited resources such as rooftop solar, battery energy storage, demand response (DR) technologies and programs (such as smart thermostats, controllable water heating and HVAC equipment) managed electric vehicle charging, vehicle-to-grid systems, energy efficiency, and microgrids. For an individual customer, DERs can lower energy bills, increase control over energy use, and, when paired with storage or other backup capability, sustain critical loads during an outage. Some DERs, such as standalone rooftop solar and energy-efficiency measures, primarily provide value through on-site generation or reduced electricity use but generally cannot respond to a specific grid event (i.e., are non-dispatchable). Dispatchable DERs—including batteries, managed EV charging, vehicle-to-grid discharging, smart thermostats, controllable water heaters, and solar paired with storage—can increase output, reduce consumption, or shift electricity use in response to grid conditions at the local feeder level and when controlled and aggregated to provide broader grid services.

The system-wide value of DERs grows when many individual distributed resources are coordinated through a **virtual power plant (VPP)**. A VPP uses communications and control systems to aggregate participating DERs and operate them as a flexible grid resource. Rather than using a centralized power plant or a single large battery, a VPP can simultaneously call on many smaller resources located across the distribution systems, including from behind-the-meter resources located in homes, businesses, and public facilities or from front-of-the-meter resources connected to the distribution system. For customers that own or host the DER and participate in a VPP, they receive compensation or other incentives when their DERs various flexibility, generation, storage, or load-reduction services.

Aggregated DERs can provide multiple types of grid services, including reducing peak load by shifting electricity use or providing energy (electricity), capacity (commitment of availability to produce electricity), and ancillary services that support power quality (e.g., frequency regulation). In addition to grid services aimed at the wholesale market, these DERs can also be optimized at the distribution system level to defer or delay distribution system capital investment. Aggregating and orchestrating DERs to provide these grid services requires establishing operational and technical protocols, both at the retail and wholesale market levels (see Section 5.2 for additional discussion on the necessary policies required to enable VPPs/DER aggregation and market participation).

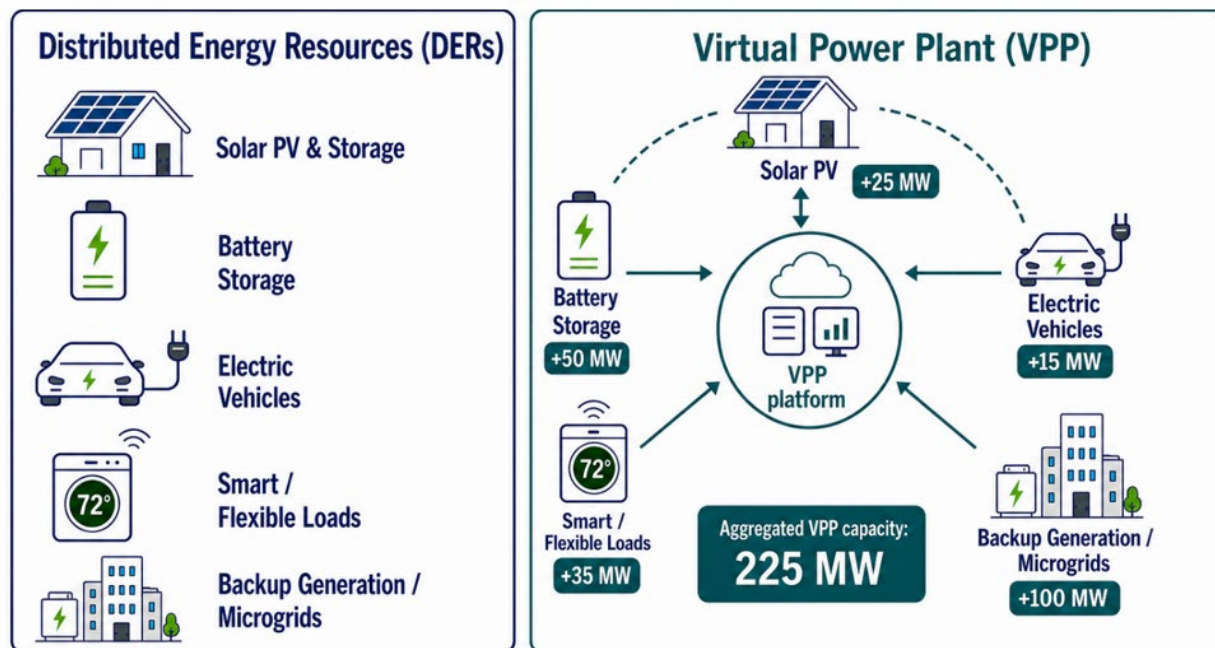
Figure 2: Aggregating Distributed Energy Resources to Create Virtual Power Plants

Figure 2: Illustration of standalone Distributed Energy Resources (DERs) versus aggregated DERs into a Virtual Power Plant (VPP). Aggregated VPP capacity figures are illustrative.

An individual DER can provide benefits to customers as a standalone investment, such as a home solar and storage system can be set up to reduce a household's energy costs and enhance household reliability and resilience. These individual resources can also provide localized distribution value when orchestrated against distribution system constraints down to the feeder level. When DERs are aggregated and orchestrated to provide grid services, such as through a VPP program, the value they can provide for the grid and asset owners increases beyond distribution system value and can provide upstream energy, capacity, and ancillary services value. As Figure 2 summarizes, VPPs can provide grid capacity to help meet growing demand; improve affordability through deferring or avoiding new generation, transmission, or distribution buildout; and provide locational resilience and backup power at the community level.²⁷ In addition to providing grid and customer value, DERs can be quick to deploy (deployed in months versus multiple years) and at lower cost than traditional generation and transmission infrastructure buildout to help meet near-term energy needs.²⁸

A September 2025 value-of-solar analysis conducted by Dunskey Energy prepared for the Piedmont Environmental Council using the National Standard Practice Manual (NSPM) framework assessed both quantitative and qualitative benefits of customer-sited solar PV in Dominion's territory, spanning generation, transmission and distribution, and Commonwealth-level impacts such as emissions reductions, public health, and economic activity, and found a combined overall value of approximately \$0.40/kWh in 2025, declining to approximately \$0.34/kWh by 2035 as the grid decarbonizes.²⁹ A companion analysis found that pairing solar with storage increases this value by nearly 12%, to

²⁷ U.S. DOE Pathways to Commercial Liftoff Report: Virtual Power Plants (2023).

²⁸ U.S. DOE Pathways to Commercial Liftoff Report: Virtual Power Plants 2025 Update (2025).

²⁹ Dunskey Energy + Climate Advisors, *Value of Solar Analysis*, prepared for the Piedmont Environmental Council (Sept. 2025), at 4, 6, <https://www.pecva.org/wp-content/uploads/value-of-solar-report-pec-final-sept-2025.pdf>.

approximately \$0.45/kWh in 2025, meaning storage contributes an incremental value of roughly \$0.05/kWh on top of standalone solar.³⁰

Figure 3: VPP Value Proposition

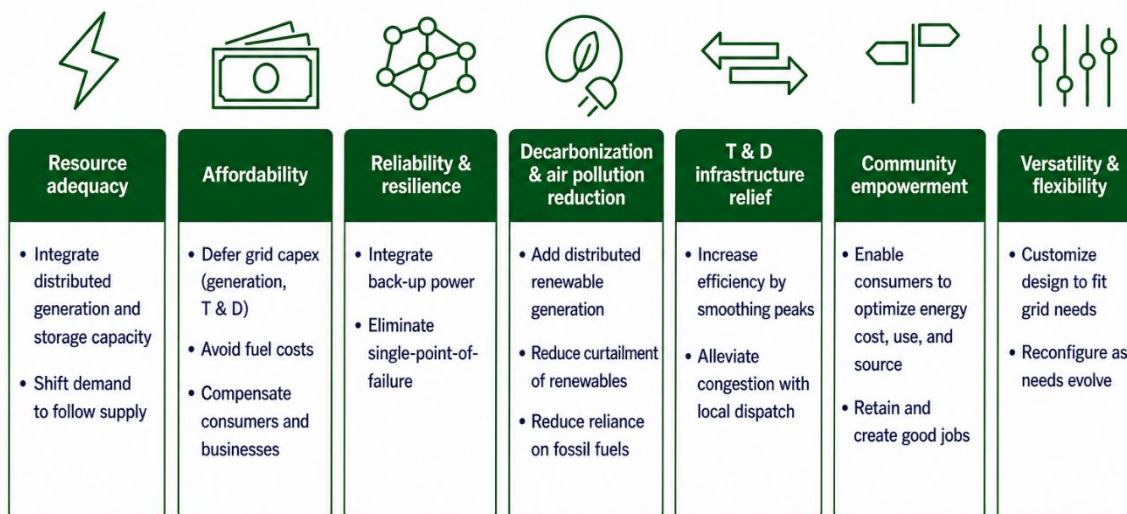


Figure 3: VPP Value Proposition. Source: DOE Virtual Power Plant Liftoff report.

Aggregated DERs can provide grid services at both the retail level through utility programs and at the wholesale level (for Virginia, this is the PJM wholesale market). In wholesale markets, there is an important distinction between DERs that can inject energy into the grid (e.g. energy storage, EVs) and DERs that do not inject energy and modify load (e.g., smart thermostats, automated load controls). The latter typically participate in markets through long-established demand response pathways. We note that, though demand response rules already allow DER participation in the wholesale markets, FERC Order 2222 allows for aggregation of both flexible load and injecting resources, the latter of which did not previously have an aggregation pathway at the wholesale level.

Many states and utilities are already seeing the value of deploying and aggregating DERs to address grid needs at lower costs (see Case Study 1 and Case Study 2). Analysis from the Brattle Group, a premier global economics consulting firm that has shaped regulatory policy and market design across the US, estimates that improving grid utilization through DERs and load flexibility could save customers of vertically integrated U.S. utilities \$110–170 billion over the next decade. Modeling a mid-sized utility interconnecting one gigawatt (GW) of new load, Brattle found that meeting half of that growth through self-supply, peak-hour flexibility, and a 500 MW DER portfolio reduced average rates by 3.4% and increased system utilization by 10%, while also shortening large-load interconnection timelines from five-to-ten years to one-to-five years.³¹ A separate Brattle study of California's Demand Side Grid Support program projected \$28–206 million in net system cost savings from 2025–2028 as statewide distributed-storage capacity nearly doubles.³² Importantly, recent locally focused analysis points to the same conclusion for Virginia. A 2026 study prepared for Solar United Neighbors estimates that the

³⁰Id. at 7–8 (same sourcing flag as note 1 applies).

³¹ Ryan Hledik, Long Lam, and Kate Peters, *The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability* (Boston: The Brattle Group, prepared for GridLab and Utilize Coalition, March 2026), <https://www.brattle.com/wp-content/uploads/2026/03/The-Untapped-Grid-Mar-2026.pdf>.

³² “The Demand Side Grid Support Program: An Assessment of Scale and Value”

Commonwealth could realize a potential of \$288.2 million in savings by 2028 through adopting a portfolio based on existing DER statutory requirements.³³

Case Study 1: Customer Savings Realized Through Green Mountain Power's VPP³⁴

Green Mountain Power (Vermont) — Utility-Operated Residential Battery VPP: Through its "bring your own device" and tariffed battery-lease programs, GMP has aggregated more than 10,000 residential batteries and utility-scale storage into a VPP that reached 110 MW as of July 2026. GMP reports \$11 million in customer savings in 2025, and in July of 2026 the utility **saved customers approximately \$6 million during a single July 2026 heat event** by dispatching roughly 90 MW of stored energy instead of purchasing more expensive peak power. GMP's successful aggregation of DERs has also enabled the utility to retire two peaker plants.

3.2 How DERs can address Virginia's evolving energy needs

DERs can help meet Virginia's evolving near-term and long-term energy needs, including electricity demand growth, improving energy affordability, and advancing the Commonwealth's clean energy objectives. At the same time, these resources enable households and small businesses to participate in and benefit from this growth.

Meeting Virginia's growing demand: The Commonwealth's electricity demand is growing rapidly³⁵. Meeting growth of this magnitude solely through new central-station generation as well as new transmission and distribution infrastructure would require significant time, with the average time to complete new transmission projects in the U.S. currently around 10 years.³⁶ Higher levels of DERs can help interconnect more load in a shorter timeframe: national modeling from the Brattle Group finds that load interconnection timelines can fall from the current level of five-to-ten years to one-to-five years when distributed energy resources and related technologies are used to increase system utilization.³⁷ Increasing investments in dispatchable VPPs that are capable of providing both distribution system benefits and broader grid services can shorten timelines to meet anticipated load growth.

Supporting affordability: A framework that pays DERs for grid services allows Virginia to make fuller use of the grid infrastructure that already exists, deferring or avoiding costlier investments in new transmission and distribution infrastructure, as described in Section 3.1. As noted in the 2026 Virginia Plan, inflation-adjusted electricity prices in Virginia actually declined between 2019 and 2024, but that trend has reversed as demand growth outpaces supply. For example, Dominion Energy projects residential electricity prices to rise approximately 60% over the next decade.³⁸ DERs interconnected to existing infrastructure and aggregated as VPPs — particularly those located within congested parts of the grid — can help to mitigate these rising costs faced by ratepayers statewide.

³³ "Value of Distributed Energy Resources in Virginia"

³⁴ Green Mountain Power. "GMP's Growing Stored Energy Network Delivers \$6M in Savings During July Heat Wave." July 28, 2026. <https://greenmountainpower.com/news/gmps-growing-stored-energy-network-delivers-6m-in-savings-during-july-heat-wave/>.

³⁵ Virginia Energy, Office of the Chief Energy Officer, and Secretariat of Commerce and Trade, 2026 *Virginia Energy Plan* (Oct. 2026), at 22 (Section 2C, "Electricity"), <https://energy.virginia.gov/public/documents/Virginia%20Energy%20Plan/2026%20VEP%200.1%20.pdf>.

³⁶ DOE Tx assessment: https://www.energy.gov/sites/default/files/2024-10/DOE_OP_2024_Report-Transmission_Impact_Assessment.pdf

³⁷ Ryan Hledik (Principal, The Brattle Group), as reported in "Better grid utilization could save customers \$170B: Brattle report," *Utility Dive*, March 23, 2026, <https://www.utilitydive.com/news/better-grid-utilization-could-save-customers-170b-brattle-report/815436/>; see also The Brattle Group, *The Untapped Grid: How a Better Utilized Power System Can Improve Energy Affordability* (commissioned by GridLab and the Utilize Coalition, March 2026), <https://www.brattle.com/the-untapped-grid/>.

³⁸ Virginia Energy (Commonwealth of Virginia, Department of Energy), 2026 *Virginia Energy Plan, Executive Brief* (Richmond, VA, October 2026), <https://energy.virginia.gov/public/documents/Virginia%20Energy%20Plan/Energy%20Plan%20Executive%20Brief%201.pdf>. The Executive Brief's inflation-adjusted price-decline finding draws on Lawrence Berkeley National Laboratory analysis; the 60% figure reflects utility integrated-resource-plan projections as cited in the Executive Brief under status quo conditions.

Case Study 2: Efficient VPP program startup with limited investment^{39,40,41,42}

National Grid (New York, Massachusetts): National Grid developed and launched the ConnectedSolutions “bring-your-own-device” VPP in less than four months, bringing up to 250 MW of low-cost, low-emissions peaking capacity in Massachusetts and New York with an upfront investment of \$500,000 to stand up the VPP. In this configuration, National Grid contracts with EnergyHub, a vendor that integrates multiple DER software systems into one platform called Edge DERMS (formerly Mercury DERMS) with the heterogeneous aggregation controlled as one cohesive, utility-scale resource. National Grid sends notices to EnergyHub in advance of peak hours to dispatch demand reductions from the customer-owned DER aggregation that EnergyHub manages on the utility's behalf. This example demonstrates how VPP aggregation can be low cost and require minor changes to internal organizational operations to implement; system integration is low, with a National Grid employee logging into EnergyHub's online portal to send instructions and collect data.

By year-end 2020, Massachusetts' participation in the ConnectedSolutions program (of which National Grid is one of several implementing utilities) had reached about 34,000 participants and 310 MW of enrolled capacity, more than triple the state's 2020 Clean Peak Energy Standard goal of 100 MW. National Grid specifically enrolled 14,975 participants that year, spent \$1,925,661 in planned program costs, generated \$3,978,280 in planned benefits (a benefit-to-cost ratio of roughly 2.1-to-1 for National Grid's program alone), and paid out \$6,271,500 in total grid services compensation across its Massachusetts battery programs in 2020.

The program has grown substantially since then. As of 2026, ConnectedSolutions now spans more than 800 MW of flexible capacity and over 280,000 enrolled devices across five participating utilities and energy service providers, demonstrating impactful scale. National Grid has also begun using ConnectedSolutions to address localized grid constraints directly. Its ConnectedSolutions+ initiative, piloted in 2025 in three feeder-constrained areas pays bonus incentives (reportedly around 40% above standard ConnectedSolutions rates) to customers in those zones to test demand response as a non-wires alternative to traditional distribution upgrades, and has since expanded to more than a dozen additional Massachusetts communities. Separately, National Grid and Eversource, in partnership with EnergyHub, Sunrun, and The Mobility House, launched a 2026 pilot enrolling vehicle-to-grid (V2G) capable electric vehicles into ConnectedSolutions, building on National Grid's existing use of V2G for light- and medium-duty fleets, starting with electric school buses. According to EnergyHub, National Grid's program alone has delivered \$60 million in net benefits to date, with a 3:1 benefit-to-cost ratio on customer incentive spending in 2025.

Accelerating clean energy goals: Rewarding the value of DERs with attractive economics will help to drive investments in batteries, EVs, and solar PV generation as well as the aggregation of these resources, creating active, dispatchable, and decarbonized grid assets. Improving DER adoption will support Virginia's carbon free electricity goals by 2045 and 2050.

3.3 The Task Force's Vision for DERs in Virginia

Recognizing that DERs can play an integral role in meeting Virginia's dynamic energy challenges, the Task Force has focused on identifying regulatory, policy, and programmatic strategies that accelerate DER

³⁹ EnergyHub, “National Grid's Pioneering Residential BYO-Battery Demand Response Program,” <https://www.energyhub.com/news/national-grid-residential-battery-demand-response>

⁴⁰ EnergyHub, “ConnectedSolutions: A framework to scale flexibility programs through a unified program design” (2026), <https://www.energyhub.com/resource/connectedsolutions-a-framework-to-scale-flexibility-programs-through-a-unified-program-design>.

⁴¹ National Grid, 2026 Massachusetts Non-Wires Alternatives Request for Proposals (Summer 2026), https://www.nationalgridus.com/media/pdfs/bus-partners/non-wires-alternatives/ma_rfp_summer2026_v2.pdf

⁴² “Eversource, National Grid Pilot Vehicle-to-Grid in Massachusetts,” *The EV Report* (2026), <https://theevreport.com/eversource-national-grid-vehicle-to-grid-massachusetts>.

deployment and market participation. The Task Force defined a vision for DERs in the Commonwealth to inform deployment strategies and approaches:

*A Virginia energy system where **all types of DERs are valued as integral, scalable grid resources—enabled to deliver and be fairly compensated for providing cost-effective grid services to meet Virginia’s energy needs** (affordable, reliable, clean, safe, secure, and resilient power) through market and regulatory designs that build on the Commonwealth’s existing foundations for DER deployment and evolve with technology, markets, and system innovations.*

Under this vision, homeowners, renters, businesses, local governments, institutions, and industrial customers have transparent and accessible opportunities to invest in DERs and participate in energy markets. Customers should be able to understand the benefits, responsibilities, and compensation associated with participation; retain appropriate choice and control over their equipment; and receive a fair return when their resources provide measurable value to the grid. Utilities, cooperatives, aggregators, and other market participants should likewise have clear rules and incentives to integrate DERs into planning and operations and to aggregate eligible resources into VPPs capable of providing energy, capacity, peak-demand reduction, and other grid services at meaningful scale.

This vision reflects broad and consistent support across Task Force members and Virginia stakeholders, including feedback gathered through public webinar/stakeholder convenings and Task Force meetings, where industry, advocacy, and utility participants alike affirmed the need for accessible, transparent DER and VPP participation pathways. The Task Force also recognizes that the DER and VPP market is evolving rapidly, with new technologies, business models, and applications emerging on an ongoing basis. Accordingly, Virginia’s policy and program design should be deliberately structured to enable and encourage continued innovation rather than locking in a static set of technologies or approaches. This will enable the Commonwealth to sustain its leadership position as the market matures.

Near-Term and Long-Term Trajectory

Near-term: The Virginia legislature enacted legislation requiring Dominion Energy to develop the state’s first VPP pilot of up to 450 MW of DERs (SB 1100).⁴³ The state has seen additional legislative progress, including a VPP pilot in Appalachian Power service territory, large load demand flexibility programs, statutory storage targets, and grid utilization metrics (see Appendix D). Building on this momentum and on NEM progress to date, **Virginia’s near-term opportunity is to move from a set of individual DER programs (shared solar, standalone storage targets, demand-flexibility pilots) toward a common, coordinated DER deployment and aggregation framework, taking a systems approach to comprehensively support deployment at scale.** Near-term objectives are also shaped by FERC’s Order 2222 compliance timeline, which has established a proposed compliance deadline of February 1, 2028, for PJM to implement operational and technical changes to allow VPPs to participate in wholesale energy, ancillary services, and capacity markets.⁴⁴ As described in Section 5.3, Virginia can support harmonizing state-level policies with implementation of FERC Order 2222 so that aggregated DERs can better participate in PJM wholesale markets in the future, complementing current opportunities for DERs to participate as demand response resources.

Long-term: Over the longer term, DERs and VPPs are positioned to become a standing component of how Virginia balances a decarbonizing, increasingly variable generation fleet against continued load

⁴³Code of Virginia § 56-585.1:16, *Virtual power plant pilot program* (enacted as HB 2346/SB 1100, “Community Energy Act,” 2025), <https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1:16/>.

growth, a powerful complement to the utility-scale solar, wind, and storage buildout called for in the Virginia Clean Economy Act. DERs will improve the utilization of these bulk generation investments and give the Commonwealth lower-cost, faster-to-deploy tools to keep pace with rapid, uncertain load growth in future years. DERs are also envisioned to become integral tools in distribution system planning over the long term, with the Commonwealth’s utilities considering DERs alongside traditional grid infrastructure solutions in their integrated resource planning.

Case Study 3: Coordinated Dispatch of over 100,000 Residential Batteries During Evening Peak⁴⁵

Sunrun & Tesla (California) — On July 29, 2025, more than 100,000 residential batteries delivered approximately 535–539 MW during the 7:00–9:00 PM peak period. Sunrun contributed approximately 360 MW. The fleet produced flat, predictable output comparable to a conventional peaking resource. The 539-megawatt dispatch was equivalent to the output of a mid-size natural gas plant. Participation was facilitated through DSGS and ELRP programs, and the impact demonstrated that aggregated home batteries can perform like a utility-scale peak resource.

Achieving this vision will require market, technical, and regulatory actions to further support DER adoption and aggregation, with broad engagement and participation from Virginia utilities, DER providers and VPP aggregators, the SCC, state agencies, consumer and energy advocates, and other stakeholders. Actions to support Virginia moving further toward these long-term outcomes are discussed in *Section 5: Task Force Findings, Recommendations, and Path Forward*.

⁴⁵ Ryan Hledik, Kate Peters, and Purvaansh Lohiya, *Assessing VPP Performance: Impacts of a Test Event in California* (presentation, The Brattle Group, prepared for Sunrun and Tesla, August 1, 2025), <https://www.brattle.com/wp-content/uploads/2025/08/Assessing-VPP-Performance-Impacts-of-a-Test-Event-in-California-1.pdf>.

4. Current State of DERs in Virginia

This section provides an overview of the current status of the electricity sector and DER deployment in the Commonwealth to contextualize the need for the recommendations put forward by the Task Force in Section 5, which will serve to drive aggregation of the existing resources shown below in Figure 4. It also describes the current status of FERC Order 2222 in Virginia, which also informs recommendations in Section 5.

4.1 Legislative and Regulatory Foundations*

Virginia Foundations

Building on legislative milestones of the last decade, the Commonwealth made significant headway in 2026 expanding its DER deployment outlook through targeted legislation passed by the General Assembly. The *Virginia Clean Economy Act's* (2020) mandate to transition the Commonwealth's two major investor-owned electric utilities toward carbon-free power by midcentury was amended by the *Distributed Generation Expansion Act* to require distributed generation comprise a greater share of RPS compliance obligations (from 1% to 4.5%).⁴⁶ The General Assembly also authorized expansion of Dominion and Appalachian Power's combined original 250 MW shared solar programs (which are fully subscribed) to a combined 625 MW;⁴⁷ statutory storage procurement targets were raised to over 20,000 MW by midcentury, with a 10% behind-the-meter carveout goal;⁴⁸ a new statewide automated permitting platform for residential solar projects was authorized for rollout in 2027;⁴⁹ SB1021 and HB2413 have also required more comprehensive planning at the distribution level; and Dominion Energy launched a first-of-its kind VPP pilot program to aggregate up to 450 MW of DERs.⁵⁰

Task Force discussions highlighted these accomplishments as significant milestones which will drive near- and long-term DER deployment growth. However, the Task Force's authorizing legislation point to the need for a comprehensive set of regulatory, market, and technical actions to ensure DERs achieve their full market potential, allowing them to maximally support reliability, cost efficiency, and decarbonization objectives as Virginians face disruption in the electric power sector.

Federal / Wholesale Foundations

Virginia's DER deployment and market integration landscape is impacted by federal and PJM wholesale processes and rules as well.

Historically, DERs have participated in PJM primarily as demand response resources under FERC Order 719 (which opened wholesale markets to aggregated demand response) and FERC Order 745 (which mandated that economic demand response be compensated at full locational marginal pricing alongside generation).

*A full list of relevant legislation is located in Appendix D.

⁴⁶Virginia General Assembly, House Bill 628 / Senate Bill 175, 2026 Regular Session.

⁴⁷Virginia General Assembly, Senate Bill 254 / House Bill 807 and Senate Bill 255 / House Bill 809, 2026 Regular Session; Virginia Energy, "Shared Solar and Community Solar," Commonwealth of Virginia, accessed August 2026.

⁴⁸Virginia General Assembly, House Bill 895 / Senate Bill 448, 2026 Regular Session, building on targets set by the 2018 Grid Transformation and Security Act and the 2020 Virginia Clean Economy Act.

⁴⁹Virginia Energy, "Solar Energy," Commonwealth of Virginia, accessed August 2026; Virginia General Assembly, House Bill 590 / Senate Bill 382, 2026 Regular Session.

⁵⁰Code of Virginia § 56-585.1:16, *Virtual power plant pilot program* (enacted as HB 2346/SB 1100, "Community Energy Act," 2025), <https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1:16/>.

The Federal Energy Regulatory Commission (FERC) issued Order 2222 in September 2020 to remove barriers to the participation of DER aggregations in the capacity, energy, and ancillary services markets operated by the regional system-market operators, such as PJM. FERC’s rationale for the order is that aggregation allows DERs to meet wholesale market minimum size and performance requirements they could not meet individually, thereby enhancing competition and market efficiency.⁵¹

While FERC Orders 719 and 745 established long-standing frameworks for demand response and load curtailment, FERC Order 2222 expands beyond demand response by enabling heterogeneous DER aggregations—which may include behind-the-meter batteries, demand response, and solar—to inject power and provide wholesale capacity, energy, and ancillary services directly.

PJM will implement FERC Order 2222 fully on February 1, 2028, and will allow DER aggregations to begin registering in November 2027. However, many PJM market and operational rules will not yet be in place until after July 2027.⁵² FERC leaves several rules around DER wholesale market participation up to the states, as further explained in Section 5.3. Consequently, Virginia can establish enabling rules and regulations at the state-level to support ultimate implementation of FERC Order 2222. This aligns with the statutory requirement of the Task Force to make recommendations to harmonize the Commonwealth’s interconnection and retail frameworks with PJM’s FERC Order 2222 compliance plan. The relevant policies that Virginia will need to define is further discussed in Section 5.3 below.

Additionally, DERs can deliver value in the PJM process through planning and accounting mechanisms rather than direct wholesale market participation—most notably via PJM’s Peak Shaving Adjustment (PSA) framework.⁵³ Through a PSA, instead of bidding into auctions as a power supply (like demand response or FERC Order 2222 aggregations), utilities use approved retail DER programs—such as home batteries, smart thermostats, or flexible commercial loads—to prove they can cut demand during peak hours. PJM then decrements that expected reduction directly from the region’s peak demand forecast before capacity auctions run. By shrinking the peak forecast up front, the utility has to buy less wholesale capacity, which lowers regional capacity costs and reduces customer bills.

This offers Virginia an immediate pathway to capture savings through state and utility programs today, separately from other demand response and FERC Order 2222 wholesale market options. This PSA pathway has recently been an area of focus ahead of PJM’s forthcoming Reliability Backstop Procurement capacity auction to try to fill an ~6.8 GW capacity shortfall.⁵⁴

In summary, there are three categories – with various alternative sub-pathways -- for how DERs can be a part of PJM market solutions:

Pathway	Resource	PJM Pathway
Category A: Demand Response (DR)		

⁵¹ See n. 6 (FERC Order 2222 and Explainer)

⁵² FERC Order 2222 Registration Process, PJM, <https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/dsrs/2026/20260406/20260406-item-03-1--ferc-order-2222-timeline-and-registration-process---presentation.pdf>

⁵³ PJM Interconnection, “PJM Manual 19: Load Forecasting and Analysis.” (June 2026) <https://www.pjm.com/-/media/DotCom/documents/manuals/m19.pdf>

⁵⁴ PJM Interconnection, “Reliability Backstop Procurement Exhibition.” (August 2026). <https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260810/20260810-pjm-and-cra-reliability-backstop-procurement-presentation.pdf>

1	Non-injecting DR/DER as PJM resource	Participating as DR in PJM standard markets and DR programs
2	Non-injecting DR/DER as RBP resource	Participating as DR in PJM RBP auction, but contracted resources must agree to 15 year terms
Category B: DER Aggregation as a Supply Resource in PJM Markets		
3	Injecting DER as PJM resource	Participating as DER aggregation in PJM standard markets (energy, capacity, ancillary) per Order 2222
Category C: Peak Shaving Adjustment (PSA)		
4	Peak Shaving Programs - Option 1	Reduction in LSE Peak Load Responsibility in standard capacity market auctions
5	Peak Shaving Programs - Option 2	Offset of LSE procurement responsibility in the RBP. Similar to Option 1, but 5-year term. States must set rules/programs prior in the near-term.

4.2 Virginia’s DER Deployment Current State

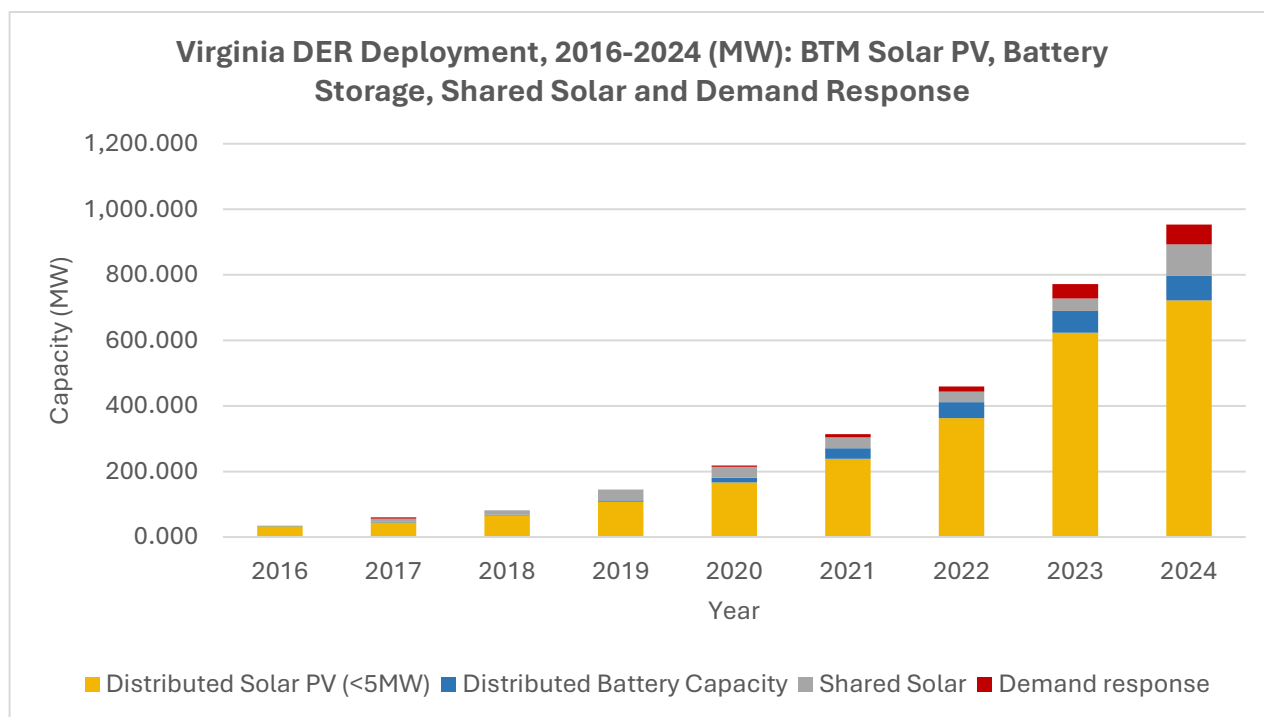
The Commonwealth’s electricity demand is growing rapidly, driven primarily by data center development as well as other commercial development and electrification in the buildings and transportation sectors.⁵⁵ Commercial electricity sales rose by nearly 30 million megawatt-hours between 2019 and 2025, a faster increase than in every state except Texas. PJM Interconnection, the regional system-market operator serving Virginia and neighboring states, forecasts that the Dominion load zone⁵⁶ will see the largest absolute increase in summer peak demand of any zone in its 13-state footprint between 2026 and 2030, with peak summer load in that zone projected to grow by an average of 5.4 percent per year over the next decade.⁵⁷ Given this growth, Dominion’s 2025 update to its 2024 Integrated Resource Plan forecasts a 2.6 GW capacity shortfall by 2031 absent new generation.⁵⁸ These conditions present cost and infrastructure challenges that, as discussed in Section 3, DERs can help mitigate if their deployment is scaled and optimized to provide grid benefits.

⁵⁵U.S. Energy Information Administration, “Commercial electricity sales have soared in Virginia, driven by data centers,” *Today in Energy*, May 5, 2026, <https://www.eia.gov/todayinenergy/detail.php?id=67664>.

*PJM’s Dominion load zone includes most of the Commonwealth’s population and hosts the largest concentration of data centers in the world.

⁵⁷U.S. Energy Information Administration, “Commercial electricity sales have soared in Virginia, driven by data centers,” *Today in Energy*, May 5, 2026, citing PJM Interconnection, *2026 Long-Term Load Forecast Report*, Dominion Virginia Power zone, Tables B1–B2, <https://www.eia.gov/todayinenergy/detail.php?id=67664>.

⁵⁸ Virginia Electric and Power Company, *2025 Update to the 2024 Integrated Resource Plan* (Richmond, VA: Dominion Energy, filed with the Virginia State Corporation Commission, Case No. PUR-2025-00184, and the North Carolina Utilities Commission, Docket No. E-100, Sub 214, October 15, 2025), <https://www.dominionenergy.com/-/media/content/about/our-company/irp/pdfs/2025-integrated-resource-plan-update.pdf>.

Figure 4: Virginia's Historical DER Deployment**Figure 4: Virginia's DER deployment (MW) between 2016-2024.*

The Commonwealth has seen rapid growth in DER deployment over the last ten years. As depicted in Figure 4, Between 2016 and 2024, the combined capacity of DERs grew approximately 25-fold to about 858 MW, of which BTM solar and battery storage systems (<5 MW), contributed 798 MW and other DERs 60 MW. By 2024, Virginia had approximately 768 MW of distributed solar (94% customer owned, 6% shared solar) and 76 MW of battery storage capacity. This represents a **compound annual growth rate (CAGR) of 48.5% since 2016**.

Shared solar represents a small share of existing distributed solar, but is set to grow as a result of the legislative updates authorizing an expansion of the Virginia's Shared Solar Program.⁵⁹ As of 2026, 745 MW of shared solar programs have been allocated, representing nearly 100 shared solar projects, ranging in size from 1-5 MW.⁶⁰ While total mobile storage capacity is not included in Figure 4 due to limited data, the Commonwealth has significant existing technical potential for managed charging and vehicle-to-grid (V2G) services; according to the Virginia DMV, there were over 140,000 PHEVs and EVs registered in the Commonwealth as of 2025, growing from under 8,000 in 2017 – a combined annual growth rate of approximately 39%.⁶¹

* Deloitte, "Virginia DER Baseline — Solar PV + BESS," internal analysis, August 21, 2026, based on U.S. Energy Information Administration, Form EIA-861, Net Metering file; proprietary BTM storage vendor data for Virginia; Lawrence Berkeley National Laboratory, Tracking the Sun (battery attachment rates); and US DOE Alternative Fuels Data Center. Battery figures are a modeled estimate blending EIA-861 data with vendor and LBNL attachment-rate data, rather than a direct census.

⁵⁹ Va. Code Ann. § 56-594.3, *Shared Solar Programs; Phase II Utility*, as amended by 2024 Va. Acts chs. 715 & 763, and 2026 Va. Acts chs. 670 & 671, <https://law.lis.virginia.gov/vacode/title56/chapter23/section56-594.3/>.

⁶⁰ "Shared Solar Program" 2020. Dominion Energy. 2020. <https://www.dominionenergy.com/virginia/renewable-energy-programs/shared-solar-program>; "Shared Solar Program." 2026. Appalachian Power. 2026. <https://www.appalachianpower.com/clean-energy/renewable/solar/shared-solar-program>.

⁶¹ Virginia DMV data, provided by Virginia Energy.

Despite a decade of distributed solar growth, Virginia has seen slower adoption of DERs compared with similarly sized states, and experienced slower growth rates in 2024 than previous years, as shown in Figure 4 (note: 2025 is not represented in the chart yet due to data availability). According to analysis performed by Deloitte Consulting, DER adoption in Virginia is expected to continue growing under current market conditions, reaching an estimated ~9 GW by 2045.⁶² However, with additional upfront incentives, the original modelling found that total DER capacity could increase to an estimated ~19 GW by 2045, over double the capacity and impact compared to the business-as-usual scenario.⁶³ Residential battery adoption remained relatively low without significant incentives, as available savings, including those from pairing storage with solar and leveraging time-of-use rates, were generally insufficient to offset system costs.⁶⁴ Commercial customers faced more favorable economics, benefiting from peak demand charge reductions, economies of scale, and continued access to the Federal ITC through 2033.⁶⁵

To test whether an additional recurring revenue stream could help address this residential sector gap, Deloitte modelled a demonstrative and conservative VPP incentive, informed by incentives offered through VPP programs elsewhere in the United States. The results indicate that a VPP incentive can encourage greater residential battery adoption by providing an additional source of financial value to customers, although were most impactful when paired with other upfront incentives. This finding is particularly important because batteries provide dispatchable capacity, whether paired with solar or deployed independently, enabling DERs to provide greater support to the grid when needed.⁶⁶

The analysis also examined the role of financing mechanisms in supporting DER adoption. Financing options that eliminate the need for an upfront customer payment, such as leases, 0% down loans, or even grants, resulted in the highest levels of adoption. However, these structures can mean that the financial benefits of DER adoption are shared between customers and third-party providers. Access to financing options also varies by technology, with some mechanisms not currently available for certain DERs.⁶⁷

Together, these findings highlight the importance of tailoring DER programs to specific technologies and customer types, recognizing that they differ in their responsiveness to incentives, value to the grid, and the types of financial support needed to encourage adoption, but with DER programs to incentivize adoption and appropriately value DERs, adoption can significantly increase.⁶⁸ The full modeling methodology, scenario assumptions, and detailed results underlying this analysis are documented in

⁶²Deloitte Consulting LLP, "Virginia: Distributed Energy Resource (DER) Adoption and Virtual Power Plant (VPP) Participation Outlook" (draft working paper, October 2, 2026), p. 10 — Low/Business-as-Usual scenario reaches 9.4 GW of installed DER capacity by 2045.

⁶³Ibid., p. 10 — High DER Adoption scenario reaches 19.3 GW of installed capacity by 2045, more than double the Low/BAU scenario.

⁶⁴Ibid., pp. 57–58 ("Residential Paired BESS" and "Residential Standalone BESS: Adoption by service area and scenario")

⁶⁵Ibid., pp. 60–61 ("Commercial Paired BESS" and "Commercial Standalone BESS")

⁶⁶Ibid., p. 69 ("Analyzing the impact of VPP incentives on battery adoption")

⁶⁷Ibid., pp. 8, 11, 71, 72

⁶⁸Ibid., p. 8

Deloitte's companion working paper, provided to the Task Force as a separate attachment to this report.⁶⁹

Figure 5 below, which compares net metered solar capacity from the most recent EIA data, illustrates this discrepancy, underscoring the need for the DER adoption strategies outlined in Section 5 for Virginia to see greater DER adoption at a greater scale.

Figure 5: How Virginia Stacks Up Against Peers

	Virginia	Massachusetts	Maryland	New York	Illinois
Approx. Population⁷⁰	8.88 million	7.15 million	6.27 million	20.00 million	12.72 million
2024 Net Metered Solar Capacity⁷¹	725 MW	3,092 MW	1,308 MW	3,815 MW	1,512 MW

Figure 5: Net Metered Solar Capacity Comparison. While growth in BTM solar has increased significantly since 2016, Virginia's growth has been outpaced by states with similar populations and clean energy targets.

Demand response technologies and programs, which range from direct load control⁷² to price-based programs,⁷³ are also steadily adding flexible load. Dominion's smart-thermostat pilot represents 60.29 MW of available flexible capacity in 2024 (more information on Virginia's existing DR programs is listed in Appendix E). And with smart thermostats and appliances, and advanced building controls, becoming commonplace, the Task Force anticipates DR to provide an even larger share of flexible load and a surplus power to the grid.

In addition to unlocking significant value by deploying new DERs and enrolling them in VPPs, there is opportunity to create additional customer and grid value by enabling existing DERs to participate in VPP programs and Dominion's VPP pilot (which includes batteries; solar, smart thermostats, and EV chargers are all included as part of the resource network) is a start. National estimates suggest that approximately 80% of installed U.S. DER capacity is not currently enrolled in a VPP, indicating meaningful near-term potential to coordinate existing resources while continuing to expand deployment of new resources.⁷⁴ Task Force discussions point to the need to prioritize efficient, timely DER deployment and indicate that the Commonwealth should pursue a strategy of accelerated adoption of new resources while facilitating enrollment of existing ones. This is reflected in the Task Force's findings and recommendations summary in Section 5.

4.3 Conclusion

Given the magnitude of potential benefits of DER and VPP deployment in the Commonwealth and the unprecedented electricity demand growth Virginia is experiencing, the Task Force has identified key barriers and recommended actions aimed at increasing DER adoption and market participation, recommending actions to address challenges in DER interconnection, compensation, upfront cost

⁶⁹Deloitte Consulting LLP, "Virginia: Distributed Energy Resource (DER) Adoption and Virtual Power Plant (VPP) Participation Outlook" (draft working paper, October 2, 2026), provided to the Virginia DER Task Force as a supplemental attachment.

⁷⁰ U.S. Census Bureau

⁷¹ EIA 861 Net Metering 2024 dataset (December 2025)

* Direct load control refers to programs where utilities remotely manage devices like smart thermostats and water heaters during peak periods.

** An example of a price-based demand response program is a time-of-use program that utilizes a price signal to encourage customers to shift electricity usage away from peak demand periods.

⁷⁴ Pew Playbook; Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future

barriers, customer awareness, and data access, among others. The following section discusses these recommendations in detail.

5. Task Force Findings, Recommendations, and Path Forward

Achieving the Commonwealth’s DER vision requires strategies for **continued DER adoption** (making adoption more attractive by mitigating up-front capital costs and addressing soft costs) and the development of durable pathways for **DER market participation**, as summarized in Figure 6. Increasing adoption expands the base of customer- and community-sited resources that may be eligible for future aggregation. In turn, transparent and reliable compensation for grid services can improve the economics of DER investments, increase customer participation, and support further deployment. DER adoption and VPP participation should therefore be understood as mutually reinforcing: a larger base of DERs creates greater potential for aggregation, while VPP participation can allow customers and communities to realize more of the value their resources provide.

Figure 6: Virginia’s DER Task Force Recommendations

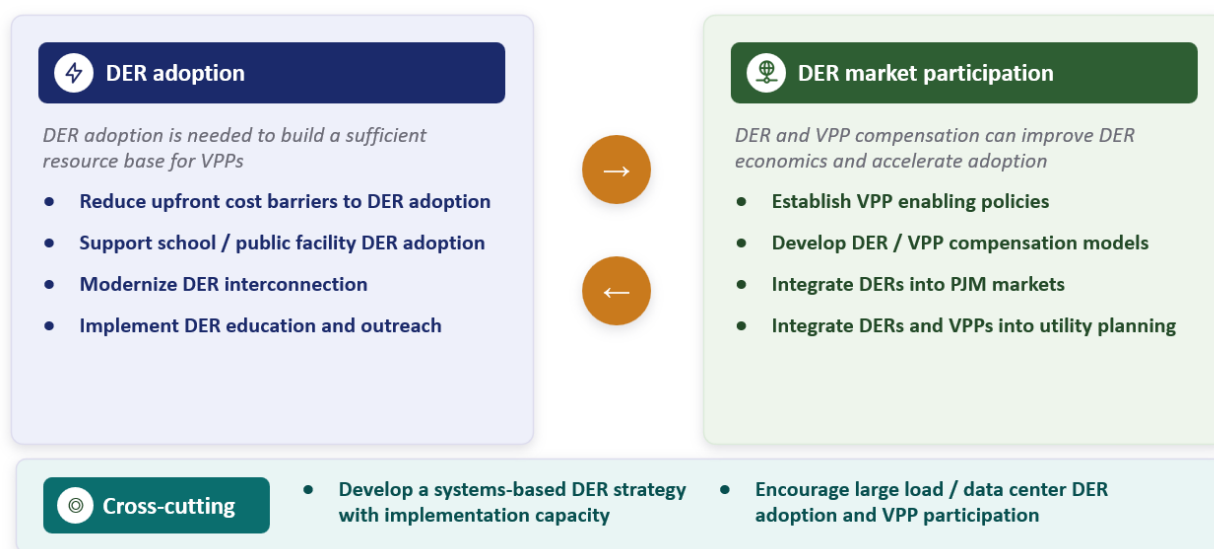


Figure 6: Primary areas identified as important to address when designing and implementing policies, programs, and procedures to benefit DER development. Source: Virginia DER Task Force analysis.

As outlined in this section, the Task Force recommends a multipronged strategy that both accelerates DER adoption and lays the groundwork for full DER market participation through VPPs. For DER aggregation and market participation, the Task Force primarily focused on *dispatchable* resources that can respond to grid, program, or market signals. Because these resources can increase output, reduce or shift electricity consumption, charge, discharge, or otherwise change operation in response to system conditions, they are particularly well suited for VPP participation and the provision of on-demand grid services.

At the same time, non-dispatchable DERs also have a role to play in offering grid services, and are important components of these recommendations. The Task Force noted that these other DER solutions remain key to Virginia’s broader DER-adoption strategy, including energy efficiency and standalone solar. These solutions bring cost, demand reduction, and decarbonization benefits even when they are not available for dispatch at a particular time.

Microgrids and community resilience hubs are also within the Task Force’s statutory scope and can provide distinct local reliability and resilience benefits, particularly for critical facilities and vulnerable communities during outages.

More details on each of the findings and recommendations to increase DER adoption and market participation are described below.

5.1 Key Findings & Recommendations

DER Task Force findings and recommendations were developed using two parallel methods for gathering stakeholder input:

1. **Free form Task Force meeting discussions, follow up interviews, and written input:** Individual discussions with Task Force members and policy leaders in peer states, verbal feedback captured during listening sessions for the industry and general public, Task Force meetings, and written questions requesting member expertise on the **greatest opportunities** and **greatest challenges** for DER deployment and VPP aggregation in the Commonwealth.
2. **Policy Surveys:** Structured questions requesting the Task Force **prioritize discreet VPP enabling policies** to determine Virginia’s current VPP policy readiness level and potential implementation sequencing. *See Section 5.2 for a more detailed overview of this exercise.*

While there were natural overlaps between Task Force inputs provided for #1 and #2, this dual approach allowed the Task Force to capture the full breadth of relevant topics from members, who represent a range of diverse industry perspectives, while also ensuring it received requisite, targeted input on a set of known VPP enabling policies.

Cross-Cutting

Recommendation 1: Pursue an Integrated, Systems-based DER Strategy with Necessary State Implementation Capacity

Finding: As noted in Section 4, Virginia has established important foundations for DER deployment and aggregation—including net energy metering, shared solar, energy-efficiency and demand-response programs, storage and distributed-generation targets, grid-utilization requirements, interconnection reforms, large-load flexibility legislation, and utility VPP pilots. However, Task Force members and stakeholders noted that these efforts were generally developed for distinct purposes and do not yet operate as a unified statewide DER strategy, consistently emphasizing that deployment, customer access, interconnection, compensation, data, utility planning, resilience, and VPP participation are interdependent and need to be addressed through holistic strategies. VPPs cannot scale without a larger base of deployable resources, while customers and public entities will not invest in DERs if financing, permitting, interconnection, data access, and compensation pathways remain uncertain or flawed.

A fragmented strategy risks solving individual problems without creating a durable market. Industry stakeholders, public commenters, local government participants, Task Force members, and Dominion Energy broadly supported building on existing programs and proceedings through a coordinated, phased approach—while differing on the appropriate balance of incentives, utility programs, market mechanisms, and mandates, as further discussed throughout this section.

Overall, taking an integrated approach can help Virginia ensure that progress is being made in all critical enabling areas and that progress in one area—such as compensation models, interconnection reform, data access, utility planning, or VPP program development—reinforces rather than undermines progress in the others, creating a durable foundation for DERs to deliver measurable affordability, reliability, resilience, and customer benefits at scale.

Task Force members and public stakeholders highlighted and supported solutions for Virginia to build enduring institutional capacity to implement a systems-based approach to sustainably carry this work forward as markets and technologies continue to evolve. Delivering a systems-based approach to collectively and comprehensively tackle issues related to DER adoption and aggregation requires sustained leadership and dedicated ownership to connect the dots and deliver the full potential value of these investments.

Virginia Energy and the Chief Energy Officer are uniquely positioned to implement and execute a DER roadmap for the Commonwealth that ensure Virginia continues moving toward its DER goals. Peer states have already proven this leaner model to work. Based on our research, there are at least 14 other states leading DER work from within their state energy office (SEO), notably including California, Colorado, Maryland, and New York. For example, the Colorado Energy Office led the creation of recommendations on creating distribution-planning objectives and expanded DER adoption, and worked with Colorado's PUC to adopt those same priorities, without creating a new statutory advisory board.⁷⁵ NYSEDA has an SVP-level DER/Integrated Solutions position and runs its own DER data system and distribution studies, and Maryland's Energy Administration (MEA) implements its own clean energy and energy efficiency programs, and formally intervenes in Public Service Commission (PSC) proceedings related to its energy goals.⁷⁶⁷⁷⁷⁸

With the Energy Plan's target of at least 10 GW of DER capacity by 2045 and 10% demand flexibility from data center load, there's further opportunity for greater tracking and reporting out of progress against those targets and the recommendations and actions implemented from this Plan to enable greater transparency and collaboration in the market.⁷⁹

Recommendation: Establish enduring state capacity to coordinate DER policy implementation and monitor an integrated, systems based, statewide strategy underpinned by a robust energy workforce. The Executive Branch should assume responsibility over DER enablement and development to ensure coordinated capacity is available to support implementation of this report's recommendations. This ongoing, implementation-focused state capability could convene DER Working Group(s) of key stakeholders as needed, track progress across related programs and proceedings, identify emerging barriers, and recommend targeted updates as conditions change.

⁷⁵ Sean Murphy, Lisa C. Schwartz, Catherine Reed, Marion Gold, and Kirsten Verclas, *State Energy Offices' Engagement in Electric Distribution Planning to Meet State Policy Goals*, Lawrence Berkeley National Laboratory & National Association of State Energy Officials (Nov. 2023), p. 18, https://eta-publications.lbl.gov/sites/default/files/naseo_electric_distribution_planning_final.pdf.

⁷⁶ New York State Energy Research and Development Authority (NYSEDA), *Residential Market Advisory Group Meeting Presentation, Q4 2025* (Oct. 28, 2025), <https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/EIBD/RMAG/2025-Q4-Residential-Market-Advisory-Group-Meeting-Presentation.pdf>.

⁷⁷ New York State Energy Research and Development Authority (NYSEDA), *DER Integrated Data System*, <https://der.nyserda.ny.gov/>.

⁷⁸ Charles Harper (NARUC Center for Partnerships & Innovation) and Kirsten Verclas (NASEO), *Engagement between Public Utility Commissions and State Energy Offices*, National Council on Electricity Policy (NCEP) Mini Guide, p. 8, <https://pubs.naruc.org/pub/BE0CB9C4-155D-0A36-3145-B283C4207921>.

⁷⁹ Virginia Energy, et al. Virginia Energy Plan (October 2026). https://energy.virginia.gov/public/documents/Virginia%20Energy%20Plan/2026_Virginia_Energy_Plan.pdf

These efforts can build on and integrate feedback mechanisms to ensure lessons learned from existing and future DER initiatives and ongoing VPP pilot programs can directly inform and support any statewide and permanent efforts.

Actions include:

1. When the DER Task Force sunsets in 2027, **the Executive Branch should spearhead the ongoing efforts to drive the systems-based approach to promoting and enabling DER development**, tracking progress and periodically reporting to the Legislature, SCC, and Executive Branch on recommendations put forward in this report (as well as subsequent DER programs and milestones). The Chief Energy Officer & VA Energy could lead a DER Working Group through practical implementation and coordination efforts and should meet regularly (e.g., monthly) to monitor program development; track progress toward DER deployment benchmarks established by the VA Energy Plan, the Distributed Generation Expansion Act, and the VCEA; resolve cross-cutting barriers; and recommend targeted legislative, regulatory, or administrative actions. The decision to establish a permanent DER Task Force can be revisited when the current Task Force sunsets in June 2027.
2. Several key recommendations in this report, including *Develop Expanded DER and VPP Compensation Models* (Recommendation 4), *Reduce Upfront Cost Barriers to Residential and Small Commercial DER Adoption* (Recommendation 8), and *Enhance Customer Education and Outreach* (Recommendation 15), **are beyond the current administrative capacity of VA Energy**; Operationalizing this report's recommended actions will require the legislature **to allocate resources for VA Energy commensurate with its expanded role** overseeing program development, monitoring, reporting, and administration. As the Executive Branch, Legislature, and other implementors translate the recommendations in this report into legislation and budget decisions, establishing realistic budgetary and staff support to execute the recommended actions will be needed.

Recommendation 2: Leverage Data Centers to Drive DER & VPP Deployment and Integration in Retail and Wholesale Markets

Finding: Data centers were identified by Task Force members and public stakeholders as a significant near-term opportunity for the Commonwealth to drive DER adoption and increase aggregation potential. Approximately 31% of the Commonwealth's total electricity consumption is driven by data center load as of 2024 and data centers are driving the majority of PJM and Virginia's demand growth outlook, creating regional and localized capacity constraints and exposing residential and small commercial customers to cost-shifting risk if not managed.⁸⁰ With well-crafted programs, new facilities can be incentivized to fund DER investment, which can be designed to directly benefit local communities as well as support broader grid needs.

The Task Force noted opportunities to continue building on recent momentum, including SB 371 and Executive Order 22 (2026), to ensure data center-driven investments can support DER adoption and aggregation. This also aligns with the 2026 Virginia Energy Plan that identifies data center demand flexibility—whether from onsite or offsite distributed energy or other demand flexibility programs—as a critical lever to reduce system costs in Virginia, as well as the 2026 Virginia Data Center Accountability

⁸⁰ 2026 Virginia Energy Plan

Framework that focuses on ensuring data center energy investments directly benefit communities, such as through DER deployments.⁸¹

The Task Force noted there are different types of value streams associated with data center DER programs that should be considered separately to ensure programs are designed effectively to achieve intended benefits. These include:

- **System-wide benefits:** These types of DER investments, aggregation, and orchestration provide system-wide capacity grid services, helping address capacity needs across Virginia and the wider PJM region. This model does not necessarily provide locational value to alleviate specific transmission constraints. An example model of this is the Google partnership with Voltus to procure 100 MWs of distributed capacity across PJM as well as their procurement of distributed capacity through Xcel’s Capacity*Connect program in Minnesota.⁸² Additional models for these types of system-wide capacity models may also be available through PJM processes (such as the Peak Shavings Adjustments mechanism that enables customers and utilities to leverage distributed energy as peak shaving resources to reduce capacity obligations and loads).
- **Localized benefits:** These types of DERs investments target very local load pockets to add distributed capacity that can alleviate a specific transmission or distribution constraint. This can be a highly valuable model to help address the localized constraints that slow customer interconnection as well as support deferring or offsetting other investments to reduce system costs. As part of its ongoing Large Load Demand Flexibility Working Group as part of SB 371, Dominion has noted that addressing these localized constraints is the highest priority area to address.⁸³ This is an emerging area across the country for how these types of local efforts could work. In September 2026, Google announced a partnership with PG&E and Rewiring America to deploy distributed energy projects to test alleviating local system constraints while also directly benefiting households and communities.⁸⁴

The capacity reduction credit structure established through SB 371 could be developed with different pathways that support both of these types of models, with appropriate distinctions given the different grid services and value delivered.

Multiple contract models were also identified as viable pathways to support these types of models—including utility-administered VPP programs, direct bilateral contracts between data centers and VPP aggregators, bring-your-own-capacity models, or other location-targeted procurements. Task Force members noted that Virginia could support multiple contract models, including utility-run programs and third-party programs.

At the PJM level, quickly developing opportunities to invest in DERs through PJM’s “Peak Shaving Adjustment” mechanism (as explained in Section 4.1) was noted by industry stakeholders as a near-term pathway for data center-funded DER models. PSA programs would reduce Virginia’s exposure to the costs associated with PJM’s Reliability Backstop Procurement auction, and could be a high value opportunity for Virginia to prioritize supporting in the near-term to capture meaningful value and create scalable models for DER investments.

⁸¹ <https://energy.virginia.gov/va-energy-plan.shtml> <https://www.governor.virginia.gov/media/governorvirginiagov/governor-of-virginia/pdf/Data-Center-Accountability-Framework.pdf>

⁸² <https://blog.google/company-news/outreach-and-initiatives/sustainability/voltus-agreement/> <https://blog.google/innovation-and-ai/infrastructure-and-cloud/global-network/data-center-pine-island/>

⁸³ <https://www.dominionenergy.com/lldf>

⁸⁴ <https://investor.pgecorp.com/news-events/press-releases/press-release-details/2026/PGE-Rewiring-America-and-Google-Launch-First-of-its-Kind-Virtual-Power-Plant-to-Help-Lower-Costs-for-All-Customers/default.aspx>

This is an area that is quickly evolving in Virginia and across the country. Given this fast pace of change, Task Force members noted that all types of programs structures—both system and local programs—should be supported in Virginia right now rather than focus just on enabling one particular model.

The Task Force can continue to monitor this area over the coming months as Dominion’s proposal model under SB 371 is submitted, greater clarity on PJM’s PSA model emerges, and other contract mechanisms and pilots are proven out to determine if any actions are needed to further support these models.

Additional opportunities exist for data center funding to support DER adoption priorities by being another source of funds outside of taxpayer or ratepayer funds to help overcome upfront cost and capacity barriers (e.g., provide incentives, used as a low-cost financing solution). This could be done via contributions to state-run funds, community benefits agreements, or other arrangements—totally separate from specific capacity credit efforts.

Across any model, several parameters were identified as important guardrails to ensure any data center funded DER programs deliver intended outcomes. These include: (1) distinguishing programs and any requirements between new versus existing data centers, including differences in retrofit and interconnection constraints; (2) preventing grid-bypass strategies and any reliance on diesel, gas, or other fossil-fuel backup generation as a demand flexibility option; and (3) protecting participating customers through clear terms, informed consent, equitable access, reliable bill benefits, and demonstrated public benefits such as local DER deployment and reduced community energy burdens.

Recommendation: Support continued development of various types of data center-funded DER models—both system and localized grid service models—to drive towards scalable contract and operational models with appropriate guardrails that advance DER adoption and aggregation into VPPs.

Near-term actions include:

1. **The DER Task Force can continue to monitor emerging models and review Dominion’s demand flexibility when submitted in January 2027 to understand if and how that effectively enables data center-funded DER models that deliver on target DER deployment and aggregation models to support system and community value.** If any gaps, the Task Force could determine if there are additional actions (legislative, executive, regulatory, or other solution) needed to support long-term success of scalable data-center DER models and include these in future updates (e.g., final July 1 Implementation Report).
2. **Engage in ongoing PJM efforts related to large loads to support solutions that advance state DER deployment and aggregation goals, with particular attention to advancing Peak Shaving Adjustment opportunities alongside other PJM market models**(e.g., PJM demand response models). This could be led by the Chief Energy Officer and Virginia Energy team, building on ongoing PJM engagements, in collaboration with other stakeholders.
3. In line with the Data Center Accountability Framework and EO22 initiatives, the Office of the Chief Energy Officer will continue to engage with stakeholders (e.g., data centers, utilities, communities, DER developers, PJM) and support pathways for data center-funded programs that advance intended DER adoption and retail and wholesale market integration goals. Any efforts through this work can help move toward repeatable, scalable models.

Medium/long-term actions:

4. The Chief Energy Officer and Virginia Energy DER team can continue to monitor ongoing PJM activity as well as SCC activity on SB 371 and additional proposals from APCo and coops to support scalable and standardized capacity reduction credit models across Virginia throughout

2027 and 2028. Focus on supporting continued alignment across Virginia retail and PJM wholesale markets as needed.

DER Market Participation (VPP Aggregation)

DER aggregation through VPPs can strengthen the business case for DER adoption by creating additional, performance-based revenue opportunities for customers, public entities, and developers whose resources provide measurable grid services. The findings and recommendations below highlight strategies Virginia can take to support DER aggregation and VPPs to help drive the market forward.

Recommendation 3: Establish VPP-Enabling Policies

Finding: Virginia has multiple foundational DER and VPP supportive legislation and pilot programs but lacks common statewide procedures needed for scalable VPP participation. As discussed in Table 2 in Section 5.2, a review of Virginia’s current policy readiness for VPP deployment shows that the Commonwealth has not yet fully addressed foundational VPP enabling policies and procedures such as **DER registration, customer data access, consumer protection, dispute resolution, cybersecurity, operational coordination, dispatch override, settlement, dual participation rules, and utility cost recovery**. Task Force members, industry stakeholders, public commenters, and utilities input broadly noted that establishing a common statewide approach across key VPP enabling policy topics, an approach that Maryland has already begun,⁸⁵ can support Virginia’s transition to scalable, permanent VPP programs—building on ongoing and forthcoming utility VPP pilots.

As further discussed in Section 5.2, the Task Force used a structured VPP prioritization process that considered the grid service to be provided, participating DER technologies, and the business model through which each service would be procured and compensated. That process identified three initial priority VPP applications for Virginia: utility-administered distribution peak shaving; data-center/large-load-VPP models; and behind-the-meter storage aggregation for PJM capacity-market participation. The process also identified the core policy topics needed to make these VPP applications viable, while recognizing that the policy topics needed to enable other VPP models—including non-wires alternatives, vehicle-to-grid applications, third-party aggregations, and utility-controlled DERs—can also be developed as Virginia’s market and policy framework matures.

Note: these initial VPP Priority Types were identified in July 2026; as market dynamics continue to unfold with ongoing PJM and data center-related shifts, other models (e.g., PJM Peak Shaving Adjustment opportunities or other SB 371 demand flexibility DER models as discussed in Recommendation 2) can continue to be developed to support meeting near-term grid needs.

See Section 5.2 for the VPP prioritization methodology, priority VPP types, Tier 1 enabling policy topics, current-state assessment, and a preliminary assessment of the minimum viable policy readiness levels to achieve.

A notable example of a prioritized Policy Topic is “Customer Data Access”. This was noted as a persistent operational barrier for aggregators. DER aggregators seeking to enroll systems in VPPs currently lack access to standardized, secure customer DER data from utilities. This largely prevents DER enrollment, dynamic dispatch, and settlement processes, generally suppressing aggregation. Task force discussions pointed to the need to establish statewide data access standards (e.g., Green Button

⁸⁵ See Maryland Public Service Commission, Case No. 9778.

Connect or utility EDI/API) to streamline aggregator customer acquisition, measurement, and verification (M&V). This barrier is also subject to active litigation at FERC over PJM’s metering and data access requirements, which should be monitored to help inform needed retail-level clarity and wholesale market alignment, as discussed in Recommendation 5.⁸⁶ To address these issues, the next milestone on this topic as noted in the table below is for the utilities to build a data exchange platform for third party access to customer data. And the recommended action is for the SCC to require the utilities to file a plan to implement such a platform.

Recommendation: Establish a statewide minimum VPP-enabling framework. Virginia should establish clear, consistent rules and procedures for DER aggregation and market participation in utility programs, including for the key policy topics identified as priority areas to address as discussed in Section 5.2. For each policy topic, initiate processes to implement regulatory changes towards the identified next regulatory milestone.

As noted below, key forums where these actions can be driven from include: existing SCC dockets (where regulatory changes can be scoped in and made in an existing rulemaking/proceedings); a “DER Umbrella Docket” as a new “catch-all” docket to cover topics as needed; continued working groups led through the DER Task Force and later through the Executive Branch; Governor’s Office; or General Assembly.

Actions include:

1. **SCC opens a DER Umbrella Docket** to address several issues, including some of the FERC Order 2222 policy topics, that do not clearly belong to an existing docket. This “catch-all” docket should be opened by February 1, 2027 in alignment with the FERC Order 2222 timing identified in the Task Force’s authorizing statute (SB 223). This docket could also be used to address any outstanding topics to enable near-term DER solutions like PJM’s Peak Shaving Adjustment mechanism if needed. The SCC could do this through existing authority, in alignment with DER Task Force recommendations and per SB 223, and/or with additional GA direction.
2. **Through Virginia Energy, the Chief Energy Officer, and/or continued working groups under the DER Task Force, begin establishing a common framework across key VPP-enabling policy topics.** These efforts—referred to collectively as the “ongoing DER Working Group” for ease—can be a forum to discuss solutions for high priority regulatory issues as a more informal collaboration venue before they are scoped into a formal docket at the SCC. This could focus on topics related to data center related contract models in particular given ongoing activities and near-term timelines (with SB 371 and related PJM activities, e.g. Peak Shavings Adjustment mechanisms, or through the Reliability Backstop Procurement). This could initially be

⁸⁶ In *Voltus, Inc. and Mission:data v. PJM Interconnection, L.L.C.*, Docket No. EL26-4-000 (Order issued July 29, 2026), FERC granted in part a complaint by independent aggregators against PJM’s requirement that third-party Curtailment Service Providers (CSPs) provide actual interval meter data—rather than statistical sampling—for residential customers with AMI meters installed. FERC found the requirement unjust and unreasonable as applied due to documented practical hurdles third parties encounter in obtaining utility meter data (including confidentiality restrictions, steep per-account fees, and slow turnaround times) that do not hinder utility-affiliated programs. Rather than compelling data disclosure over utility privacy objections, statistical sampling bypasses individual meter data where it is not reasonably accessible. Because FERC has not finalized the replacement methodology—ordering a paper hearing on implementation standards, error caps, and verification safeguards, over a dissent arguing data access is an exclusively state jurisdictional matter—this remains an active, unsettled federal proceeding that does not eliminate the need for Virginia to address data access directly at the state level.

spearheaded under the DER Task Force until it sunsets in July 2027, and then could be continued by Virginia Energy-led efforts.

3. **The SCC and the ongoing DER working group efforts can advance action on high-priority policy topics, along the lines of the actions summarized below.** Further detail on the regulatory milestones motivating these actions can be found in Section 5.2. Recommended next actions specific to PJM VPPs can be found in Recommendation 5 and next actions specific to DER Interconnection can be found in Recommendation 9.

- a) Where an action specifies the DER Umbrella Docket, the same action applies to the FERC Order 2222 Docket if that docket is created instead, and the policy topic applies to PJM VPPs as described in Recommendation 5
- b) Where a current SCC Docket is identified, if that Docket only applies to the IOUs, then the same action is recommended in the DER Umbrella Docket with respect to the Co-ops where feasible.

Policy Topic	Proposed Next Action	Additional Details
DER Registration / Enrollment	Within the current DSM docket, the SCC requires each utility to submit a manual that details a DER registration and enrollment process for any DERs not already defined to be standardized across the retail VPP programs that utility administers	
Customer Data Access	Within the DER Umbrella Docket, the SCC requires each utility to submit a Customer Data Access Plan to support 3rd party access to retail meter data	Plan includes a staged implementation timeline for a data exchange platform that evolves to the Green Button Connect My Data standard and is able to be certified by the Green Button Alliance.
Interconnection	See Recommendation 9. Sub-Recommendation C is the most relevant to VPPs	
Customer Enrollment Protection	The ongoing DER WG creates a set of customer protection rules that apply to VPP Operators and Aggregators that enroll customer-sited DERs in retail VPP programs.	These rules should be submitted to the DER Umbrella Docket in 2027
Dispute Resolution	In the DER Umbrella Docket, the SCC creates a new set of procedures, building on existing dispute resolution rules, for DER operator-EDC disputes regarding DER participation in VPP programs; The ongoing DER WG develops Data Center-EDC dispute resolution procedures regarding VPP program funding	The SCC adopts all new dispute resolution procedures no later than the launch of the SB 371 datacenter demand flexibility VPP programs

Cybersecurity	SCC requires utilities to add cybersecurity rules for EDC to Aggregator/Operator communication to current Commission ordered development of cybersecurity standards	Utilities are currently required to submit updated cybersecurity standards by December 2027
(cybersecurity – data access subtopic)	SCC requires that the EDC Customer Data Access Plans include cybersecurity rules for communication between Aggregators/Operators and the utility's customer data exchange platform	
EDC –Aggregator Coordination	Within the current DSM docket, the SCC requires each utility to submit a manual that details operational coordination protocols between Aggregators/Operators and the utility standardized for all VPP programs managed by that utility	These manuals should be submitted before completion of the utility's VPP pilots
Dispatch Override	The ongoing DER Policy WG creates a set of statewide standard dispatch override regulations and procedures that govern how an EDC may override retail scheduled and retail reactive DER and VPP dispatches.	These regulations and procedures are submitted to the SCC in the DER Umbrella Docket in 2027.
Grid Services Mechanisms	In the current development of large load interconnection and supply tariffs, including the SB371 implementation, these tariffs include provisions that enable large loads to fund utility VPP programs and be credited for bring-your-own-new-capacity (BYONC)	Retail grid services, e.g. peak shaving are already defined and authorized.
Metering	In the currently active interconnection docket, the SCC develops statewide regulations to allow DERs to use submeters (aka direct metering) to measure retail VPP transactions	
Transaction Settlement	Within the current DSM docket, the SCC requires each utility to submit transaction settlement procedures standardized for all VPP programs managed by that utility	These procedures specify data structures and flows from customer retail meters and DER meters as well as settlement process timeframes
Dual Participation	In the DER Umbrella Docket, the SCC requires each utility to establish a program/tariff matrix that specifies the program/tariff dual participation combinations that are disallowed.	Dual participation restrictions should be implemented and enforceable in each utility's DER enrollment process no later than the conclusion of their respective VPP Pilots
Cost Recovery	Short-term next steps are unnecessary for retail VPPs. Cost recovery can be determined on a program-by-program basis	

Recommendation 4: Develop Expanded DER and VPP Compensation Models

Finding: Virginia's net-energy-metering (NEM) framework remains an important foundation for customer-sited solar adoption and should be preserved. However, NEM is not well suited to recognize

the distinct energy, capacity, flexibility, ancillary service, avoided transmission and distribution, and locational value that dispatchable DERs (e.g., batteries, bidirectional EVs, etc.) can provide. This limits the economics of customer-sited storage, resilience hubs, and other VPP-ready resources.

Task Force discussion supported two separate strategies: 1) maintain NEM as the solar deployment foundation for residential and small commercial systems (Recommendation 8) while 2) also establishing an alternative option for DER owners to receive verifiable compensation for incremental grid services (Recommendation 4). The latter requires clear retail-wholesale coordination, including metering, dispatch, settlement, export attribution, and anti-double-counting rules, so that a resource can stack compatible retail and PJM revenue streams without being paid twice for the same service.

New York, Massachusetts, and Illinois are useful but distinct models for modernizing DER compensation that Virginia could learn from. New York's Value Stack⁸⁷ compensates DERs for the specific grid services they provide—including performance during high-value periods and in constrained locations—while pairing tariff revenues with a targeted deployment incentive; Massachusetts demonstrates a performance-based tariff that can operate alongside net-metering credits; and Illinois illustrates how incentives can include location and equity adders. Virginia can adapt these lessons by preserving NEM (Recommendation 7) while adding transparent, performance- and location-based compensation options (Recommendation 4) for separately measured DER services, with rules suited to Virginia's utility structure, affordability priorities, and PJM market context.

To develop a durable statewide framework, Virginia can leverage near-term utility VPP pilot filings (such as Dominion's November 15, 2026 tariff proposal) alongside the SCC's newly adopted Jurisdiction-Specific Test (JST). While related, the JST and a value-stacking tariff serve distinct but complementary functions. As further discussed in Recommendation 6, the JST is a benefit-cost analysis (BCA) screening tool that evaluates whether an overall utility program is cost-effective by weighing system impacts—including avoided T&D expenditures, peak capacity reductions, and risk mitigation—against state policy goals. In contrast, a value-stacking tariff is an operational compensation mechanism that determines the actual cash flow or bill credit a customer earns for verifiably delivering individual, dispatchable grid services (e.g., peak shaving or local congestion relief). Transparent avoided-cost methodologies established in the JST proceeding can provide the pricing foundation for the tariff's unbundled value layers. In structuring these compensation layers, the Task Force discussed how the utility avoided cost could be the baseline floor, with full retail-rate compensation functioning as a policy ceiling to unlock discrete grid performance revenues (such as battery export or locational relief) without creating unreasonable non-participant cost shifts.

Recommendation: Establish more granular, technology-neutral valuation structures that compensate DERs for their locational and operational characteristics, such as "value stacking" compensation models that reward DERs for specific grid services: energy, capacity, locational relief, and ancillary services.

Actions include:

1. Virginia Energy (if resourced) could **coordinate with the SCC, legislature, and utilities to develop and phase-in implementation of a value-stacking compensation framework** (energy, capacity, demand-reduction, and locational-relief components); consider following New York's model of phasing the value stack framework in for larger projects first. Allow storage paired with solar and storage-only DERs to qualify for value-stack compensation.

⁸⁷ In its August 4th presentation to the Task Force, NYSEDA described its Value of Distributed Energy Resources tariff as compensating projects according to energy and grid-service value, with higher payments for resources located in congested areas or performing during peak periods; its declining-block incentive structure was used to supplement tariff revenues and support early-market project economics.

Recommendation 5: Implement Minimum Changes to Enable VPP Participation in PJM Markets via FERC Order 2222

Finding: As described in Chapter 4, VPPs consisting of demand response resources are currently able to participate in PJM wholesale markets, while VPPs consisting of injecting supply resources will be able to fully participate when PJM fully implements FERC Order 2222.

Additional opportunities for DERs through PJM's Peak Shaving Adjustment mechanism are also high value opportunities—particularly in the near-term ahead of PJM's Reliability Backstop Procurement (RBP) auction. This specific opportunity is discussed further in Recommendation 2.

The Task Force's statute directs the Task Force to make recommendations to harmonize the Commonwealth's interconnection and retail frameworks with PJM's FERC Order 2222 compliance plan, with such recommendations supporting Commission action on or before February 1, 2027. In line with this direction, with input from the Task Force members, utilities (particularly help from Dominion), and national expertise from a former FERC staffer, the roadmap in Section 5.3 outlines the state-level policy topics and regulatory milestones Virginia needs to address to harmonize with PJM's implementation and enable VPP participation.

Notably, during the Task Force and stakeholder input meetings, DER industry developers highlighted challenges with PJM rules and economics (e.g., challenges with effective load carrying capability (ELCC) values for DER aggregations in PJM) that challenge the viability of DER aggregations under FERC Order 2222. This was evidenced in PJM's June 2026 Base Residual Auction, which was the first auction where DERs were allowed to participate, yet no DER aggregations bid into the auction.

Reasons for this that were highlighted by Task Force members and stakeholders include that PJM's DER Aggregator Participation Model was not yet operational, and key market, implementation, and economic challenges persisted—including a lack of supportive state policies and conflicts between NEM and wholesale market participation. Consequently, DER aggregators will likely wait to participate in PJM markets until (a) PJM finalizes many of the system and manual changes that are upcoming, including improving the economics of these resources, and (b) states implement enabling FERC Order 2222 policies and regulations. In the meantime, given lack of supportive state policy and economics, DER aggregations will likely choose to pursue existing PJM demand response participation pathways which limit the full potential of resources that could be injecting energy into the market.

While PJM's actions here are outside of the remit of Virginia's authority, Virginia still has a role in updating its policies to enable DER aggregations to more fully participate in wholesale markets. Virginia can continue to pursue the establishment of necessary supportive policies to align state requirements with FERC Order 2222 and PJM rules and can advocate to PJM for fixing their restrictive rules that adversely impact DER aggregation participation. Accordingly, the following recommendations are specifically focused on FERC Order 2222 compliance and enablement.

Other important pathways and considerations for DERs to provide wholesale market services are discussed elsewhere, including Recommendation 2 (related to DERs participating through Peak Shaving Adjustment programs), Recommendation 3 (related to VPP enabling policies that impact both retail and wholesale processes), and Recommendation 4 (related to establishing compensation models that enable stacking across retail and wholesale markets).

Recommendation: Virginia should establish the minimum necessary compliance requirements for FERC Order 2222 using the roadmap below to build in-state foundations, so Virginia is ready once PJM's model matures.

Note that the following actions assume the creation of the policy venues recommended in Recommendation 1 and 3—including ongoing working groups through the DER Task Force (and later led by Virginia Energy once sunst) and the creation of a “DER Umbrella Docket”.

Actions include:

4. **Virginia should prioritize continued proactive engagement with PJM** (e.g., through the Office of the Chief Energy Officer, OPSI, and/or Virginia Energy) to ensure that the processes being developed are consistent and supportive of state DER and VPP goals.
5. **The SCC and ongoing DER working groups (through the DER Task Force and later through Virginia Energy) should initiate actions for each high-priority policy topic as summarized below in order for Virginia to minimally comply with FERC Order 2222.** The SCC could open a docket by Feb 1, 2027 (in line with SB 223 timelines) either a via a “DER Umbrella Docket” as noted in Recommendation 3 or a standalone FERC Order 2222 docket if necessary (though not recommended to have a standalone docket since less efficient). These actions should be taken so that rules are in place no later than Feb 1, 2028 (when DER aggregations can start participating in PJM energy and ancillary markets). Further detail on the regulatory milestones motivating these actions can be found in Section 5.2.

Policy Topic	Next Action	Additional Details
DER Registration / Enrollment	Within the DER Umbrella Docket, the SCC requires each utility to submit, by February 1, 2027, the detailed procedures by which each utility will review DERs that register to join a PJM VPP under FERC Order 2222.	These procedures will adhere to the FERC Order 2222 review timelines and provide validation to PJM that a DER has been reviewed. The SCC should require these procedures to be implemented and available to DER aggregators by Nov 1, 2027 (when DER aggregations are allowed to register with PJM)
Customer Data Access	See recommendation 3	The first stage of minimum data availability for PJM VPPs should be completed by Feb 1, 2028.
Interconnection	Through an existing or new DER Interconnection docket (as noted in Recommendation 9 and 3), threeadditional issues should be scoped into this: 1. Permission for BTM storage to export energy and be compensated in PJM markets 2. Configurations and agreements for NEM+storage to provide ancillary services 3. Configurations and agreements for storage in NEM+storage configurations to fully participate in PJM	All 2222 specific changes should be implemented by Feb 1, 2028

Customer Enrollment Protection	n/a short-term for PJM VPPs	
Dispute Resolution	In the DER Umbrella Docket, the SCC creates a set of procedures for new Aggregator-EDC disputes regarding DER participation in PJM markets under FERC Order 2222.	FERC Order 2222 specific dispute resolution procedures are available no later than Feb 1, 2028
Cybersecurity	See recommendation 3	
EDC-Aggregator Coordination	Within the DER Umbrella Docket, the SCC requires each utility to submit, by June 1, 2027, the real time operations coordination procedures between the utility and Aggregators operating PJM VPPs	These procedures will adhere to the FERC Order 2222 coordination timelines. The SCC requires these procedures to be implemented and available to PJM VPP Aggregators by Feb 1, 2028
Dispatch Override	In the DER Umbrella Docket, the SCC creates a set of statewide standard dispatch override regulations and procedures that govern how an EDC may override PJM dispatches for VPPs	These regulations and procedures are approved and implemented no later than Feb 1, 2028
Grid Services Mechanisms	N/A for PJM markets	
Metering	State jurisdictional metering rules are not applicable to metering of DERs participating in PJM VPPs	
Transaction Settlement	Within the DER Umbrella Docket, the SCC requires each utility to submit an implementation plan for supporting VPP transactions with PJM	Implementation plan should include basic functionality to support PJM VPP transactions implemented by Feb 1, 2028
Dual Participation	See Recommendation 3; the ongoing DER WG could engage with PJM to answer two open issues: 1) Configuration and metering requirements for NEM+storage installations to participate in ancillary services 2) Path for the storage asset in NEM+storage installations to fully participate in PJM markets, such as providing capacity	Dual participation restrictions should be implemented and enforceable in the PJM VPP DER registration process no later than Feb 1, 2028 These topics are also pertinent to Recommendation 9 and Virginia's rules on DER Interconnection and NEM.
Cost Recovery	In the DER Umbrella docket, SCC requires each utility to submit an investment plan for IT systems and personnel to support PJM VPPs	FERC Order 2222 related needs do not by themselves justify major investments such as a full-fledged DERMS

Recommendation 6: Align Utility Incentives and Planning Structures with DER Deployment

Finding: This dynamic reflects a structural feature of cost-of-service regulation nationally, not just a Virginia-specific anomaly. Because capital expenditures enter a utility's rate base and earn a return while operating expenses are passed through to customers with no comparable earnings opportunity, cost-of-service regulation creates a long-recognized incentive for utilities to favor capital-intensive infrastructure over third-party or utility-run DER and VPP programs, even where the latter cost less.⁸⁸

⁸⁸ See, e.g., Averch, H. and Johnson, L.L., "Behavior of the Firm Under Regulatory Constraint" (1962); see also RMI, *The Nuts and Bolts of Performance-Based Regulation* (2024).

The U.S. Department of Energy has identified integrating DERs and VPPs into utility planning and incentive structures as one of five national imperatives for VPP deployment, noting that traditional cost-of-service business models have not sufficiently incentivized these solutions at scale.⁸⁹ The Pew Charitable Trusts' 2026 DER Policy Playbook similarly recommends aligning utility financial incentives with distributed resource deployment, observing that DERs can defer or avoid the need for large, regulated infrastructure investments.⁹⁰ This gap is compounded by DERs and VPPs not yet receiving equal footing with traditional infrastructure in utility planning and operations, risking the kind of overbuilding that DERs could otherwise defer. Aligning utility incentives with DER and VPP deployment, through mechanisms such as performance-based regulation, return on equity enhancement, shared savings, and capitalization of software deployments, while also supporting distribution planning and operational integration that weighs DERs equally with traditional infrastructure can help address these types of challenges.

Virginia's Grid Transformation and Security Act (GTSA, 2018), which established a rate adjustment clause under Code § 56-585.1 A 6 allowing Dominion and APCo to recover the capital costs of electric distribution grid-transformation projects, and under which Dominion has already recovered costs for some DER-enabling investments, including its Distributed Energy Resource Management System and non-wires alternative storage pilots; this authority does not explicitly tie compensation to DER or VPP performance metrics, does not extend to third-party-owned DER assets, and sunsets July 1, 2028.

While Task Force discussions emphasized the need to advance these key DER-enabling regulatory objectives, they also acknowledged significant ongoing work that is doing just that – aligning utility incentives and planning frameworks with DER deployment (among other objectives) through working groups and legislatively mandated actions, such as:

- HB 903/SB 251 (2026), which builds on the 2025 performance-based ratemaking stakeholder input process,⁹¹ directs the SCC to consider whether a performance-based regulatory framework is in the common interest and to develop legislative recommendations.
- HB 434/SB 621 (2026), which requires ApCo and Dominion to petition the SCC to approve grid utilization metrics and directs the SCC to analyze the potential for both utilities to increase electric grid utilization through the deployment of “non-wires alternatives” (e.g., DERs, VPPs, and power stabilization equipment). The statute also requires utilization-metric findings to inform subsequent integrated resource plan filings and authorizes the SCC to establish performance-based incentives tied to utilization standards, presenting a concrete opportunity to tie DER and VPP deployment to both distribution planning and utility incentive design.
- HB 429/SB 249 (2026), which expands the integrated resource plan horizon to 20 years and requires APCo and Dominion to identify a single preferred portfolio of generation and non-generation resources, including a modeling scenario explicitly incorporating distributed and utility-scale battery storage, grid-enhancing technology, and virtual power plants using aggregated demand response. The bill also opens utility modeling data to stakeholders and establishes a work group and recurring SCC review to strengthen IRP transparency but does not

⁸⁹ U.S. Department of Energy, *Pathways to Commercial Liftoff: Virtual Power Plants, 2025 Update* (2025).

⁹⁰ The Pew Charitable Trusts, *Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future* (April 2026)

⁹¹ The 2025 report produced by the Great Plains Institute and Current Energy Group for the SCC found that Virginia's cost-of-service model leaves utilities with little incentive to control costs or correct the “capex bias” toward capital projects over lower-cost operating alternatives. It offered six recommendations, including continued rate-adjustment-clause reform, targeted performance-incentive mechanisms, and an integrated PBR framework pairing a multiyear rate plan with capex-opex equalization tools and shared savings mechanisms which are recommendations that fed directly into HB 903/SB 251's SCC-led inquiry and align with many of the noted DER Task Force report recommendations. State Corporation Commission, *Opportunities for Performance-Based and Alternative Regulatory Tools in Virginia* (HD5, 2025), prepared pursuant to HJR 30/SJR 47 (2024), <https://rga.lis.virginia.gov/Published/2025/HD5>.

require feeder- or transformer-level DER forecasting or set DER procurement targets, gaps the Task distribution-planning recommendation is designed to address.

Additionally, the SCC established the Jurisdiction-Specific Test (JST), which transitions Virginia electric utilities from legacy California Standard Practice Manual tests (Participants, UCT, RIM, TRC) to the Virginia-tailored JST as the cost-effectiveness framework for all Demand-Side Management (DSM), energy efficiency, and demand response programs. The JST formally replaces traditional multi-perspective screening tests beginning in 2029 (with interim transition guidelines spanning 2027–2028).⁹²

To build on – rather than duplicate – significant progress over the last two years, the Task Force recommends a monitoring and reporting role for itself and any expanded Virginia Energy DER team, in coordination with the Energy Commission of Virginia and both legislative committees on labor and commerce. Under this structure, the Task Force can identify any gaps or shortcomings based on the above priorities and support intervening in proceedings or contribute to working groups as necessary.

Near-term actions include:

- The DER Task Force (until sunset in July 2027) and then Virginia Energy’s DER team (if expanded) should **monitor implementation of HB 903/SB 251, HB 434/SB 621, and HB 429/SB 249 to ensure resulting proceedings and reporting frameworks remain consistent with, and do not narrow, their intended DER and VPP planning purposes**; it can and use that monitoring to inform the General Assembly’s review of whether the GTSA successor framework, ahead of the July 1, 2028 sunset, should explicitly authorize and incentivize cost-effective DER and VPP capital and operating expenditures. Key priorities expressed by various Task Force members for these ongoing efforts include:
 - Compensation mechanisms tied to DER/VPP metrics, including a return on direct DER/VPP investments and the annualized value of third party-owned DER services identified in distribution plans.
 - A standardized DER cost-benefit test, covering avoided cost of energy, avoided capacity, distribution deferral, and reliability for distribution capital projects, building on the existing Jurisdiction-Specific Test’s value stack and national best practice models such as the National Standard Practice Manual.
 - A standardized methodology for allocating distribution upgrade costs between the utility and the customer or developer, with clear, transparent triggers for cost pass-through, building on and clarifying the distribution cost-sharing program recently introduced under Chapter 315 (20VAC5-315-100), rather than establishing a separate allocation framework.
 - Requiring Dominion and APCo to use granular, feeder- and transformer-level demand and DER-adoption forecasts in their IRP distribution plans, with DER procurement targets and a formal stakeholder review process following the Colorado SB19-236 model, and support DER and VPP deployment as the SCC finalizes rulings on HB 434’s grid-utilization-metrics petitions, with initial filings due October 15, 2026.

DER Adoption

⁹² Refer to SCC Case No. PUR-2024-00120

Continued DER adoption is equally essential: VPPs can only grow if Virginia expands the base of solar, storage, flexible loads, managed EVs, energy-efficiency measures, and public-facility resources available to participate. The findings and recommendations below therefore identify strategies to reduce DER deployment barriers, improve customer access, and support the sustained buildout of DERs that can deliver customer benefits today and become grid resources over time.

Recommendation 7: Reduce Upfront Cost Barriers to DER Adoption

Finding: Reducing the upfront cost of DER equipment such as solar panels, battery storage, heat pumps, and other qualifying technologies is a critical, distinct lever for broadening adoption, separate from the ongoing-revenue mechanisms envisioned under Recommendation 4's value-stacking compensation model. Task Force members noted that alternate compensation models alone will not resolve first-cost barriers, particularly for smaller-scale systems, and that additional, complementary funding and financial mechanisms are likely needed to support greater adoption of DERs. This recommendation focuses on the cost of DER equipment itself; associated infrastructure costs tied to electrification, such as meter and service-connection upgrades, are addressed separately in Recommendation 10 (Remove Barriers to Electrification).

Financial barriers to DER adoption have also grown more pressing following recent changes to federal tax policy. The One Big Beautiful Bill Act (July 2025) eliminated the 30% federal Residential Clean Energy Credit (Section 25D) for both solar PV and standalone battery storage purchased directly by homeowners, for systems placed in service after December 31, 2025.⁹³

Separately, EPA's Solar for All program had awarded Virginia \$156 million for residential/community solar, storage, and associated upgrades for low- and moderate-income households before the EPA terminated the program in August 2025. On September 18, 2026 a federal court vacated that termination and ordered the funding reinstated nationwide. This is an evolving situation, and Virginia Energy should continue to monitor further developments and the impact on DER adoption.

Recommendation: Virginia should develop a DER funding program that is both NEM-stackable and leverages a combination of complementary mechanisms including incentives and grants, lower-cost financing, and bulk/cooperative procurement to reduce the upfront cost of DER adoption for residential and small commercial customers, while rewarding priority siting and use-case attributes (e.g., brownfields, parking canopies, agricultural land, low-income communities) not otherwise recognized by the market. The design of this program should be intentional to recognize that continued declines in the cost of storage technology, combined with well-designed state support, can help sustain adoption momentum as federal incentives recede.

Near-term actions could include:

1. **Develop targeted, meaningful incentives and grants:** The Virginia Energy DER working group (see Recommendation 1) could develop, in consultation with Virginia Energy, the SCC, and the Virginia Clean Energy Innovation Bank (VCEIB), a statewide framework of NEM-stackable incentive options and grant options (broadly applied or tailored to specific high-priority uses such as brownfields, parking canopies, agricultural land, or low-income communities) to reduce upfront cost barriers for small-scale DER adoption. Funding could come from taxpayer appropriations, ratepayer funding, large-load/data-center surcharge or other contributions (see Recommendation 2), or other resources (such as RGGI funding).

⁹³One Big Beautiful Bill Act, Pub. L. No. 119-21 (2025), amending 26 U.S.C. § 25D to terminate the Residential Clean Energy Credit — including the 30% credit previously available for both solar PV and standalone battery storage purchased by homeowners — for expenditures made after December 31, 2025.

- Funding could be provided to the existing Brownfields Fund to support DER siting on brownfield and other high-priority sites, consistent with Virginia Energy Plan priorities.
 - Funding could incorporate policy adders that reward DERs for locational attributes not recognized by the market but are a priority for the state, such as dual use sites, agrivoltaics, or brownfields. Projects enrolled in NEM or the Recommendation 4 value-stack program would be eligible.
2. **Pursue lower-cost financing options:** Consider expanding the VCEIB's budget to offer reduced-interest loans, credit enhancements, or other financing tools tailored to residential- and small-commercial-scale solar and storage, funded through some combination of taxpayer appropriations, data-center-associated revenue, Community Development Financial Institutions (CDFIs), or federal funding if it becomes available. This could include raising awareness of and expanding on Virginia's Commercial Property Assessed Clean Energy (C-PACE) program that provides no-upfront cost financing options for commercial building owners for certain clean energy solutions, with ~\$125 million in financing closed in early 2026.⁹⁴
 3. **Facilitate bulk and cooperative procurement:** Expand models such as Solar United Neighbors' (SUN) Switch Together program (the statewide solar group-purchasing initiative the Governor's Office launched in July 2026) and Solarize-style campaigns, which reduce per-unit costs through aggregated demand and competitive vendor selection.
 4. **Consider other state supports, such as DER tax credits:** Evaluate opportunities to revitalize tax credits and establish state-specific tax credits through legislation such as the "Virginia Solar Energy and Battery Energy Storage Systems Program" that had been introduced in 2026.
 5. **Virginia Energy could clarify rules around solar-plus-storage models participating in NEM—with input from utilities and other stakeholders—to address questions around separate metering or equivalent device-level verification, control and dispatch arrangements, export attribution, billing, customer protections, and anti-double-counting safeguards.** This will help ensure customers with solar have a clear pathway to adopting storage as well.
 6. **Expand agricultural net metering threshold:** Expand agricultural net metering thresholds to align with other commercial projects (from 500 kW to 3 MW) so agricultural customer-generators can host larger distributed systems without losing net metering eligibility.

Medium/long-term actions include:

7. **The General Assembly could raise the 6%-of-peak-demand net-metering cap** in the long-term if needed to support continued industry investment.

Recommendation 8: Support Schools & Public Facility DER Adoption

Finding: Virginia's public schools, colleges, and municipal facilities represent one of the largest untapped opportunities to deploy and aggregate DERs to reduce taxpayer-funded energy costs and use resultant savings for public reinvestment, strengthen resilience of critical infrastructure, and demonstrate a practical pathway to improving grid utilization and energy affordability. This aligns with ongoing analysis

⁹⁴ VPA. "C-PACE Financing Making Waves in Virginia's Commercial Real Estate Marketplace" (March 2026). <https://virginiapace.com/wp-content/uploads/2026/03/VA-CPACE-March-10-2026-webinar.pdf>

led by the Energy Commission of Virginia that is also evaluating opportunities for public schools as energy centers as part of its 2026 workplan.⁹⁵

However, Task Force members raised key education, legal, and regulatory barriers that need to be addressed to best support schools and other public facilities in taking advantage of these opportunities (e.g., education and capacity building, PPA models fit for public entities, etc.).

Recommendation: Develop a program that takes a systems approach to deploying and aggregating solar PV, flexible load, electrified fleets, and battery storage across public facilities using public and private capital to deliver energy and taxpayer savings; encourage use of existing joint procurement contracts while offering public funding to support deployment of resilience hubs and microgrids; incorporate education and direct outreach strategies to as a core component of the program to lay the groundwork for long-term adoption. Build on existing programs, such as Virginia Energy’s Energy Savings Performance Contracting (ESPC) and Demand Response programs for publicly owned buildings.⁹⁶

Near-term action could include:

1. **The General Assembly could establish a dedicated school and public facilities DER adoption program.** This could include requirements for leveraging existing cooperative procurement contracts where feasible to reduce costs and accelerate timelines; establishing streamlined interconnection processes for eligible school projects ≤ 1 MW (e.g., waivers on site-level DTT/telemetry requirements, 30–60-day permission-to-operate timelines, and by-right permitting); clarifying pathways for systems to participate in PJM markets; support pathways for large energy customers to support school-based projects to enhance project economics. Additional grants to enable microgrid and resilience hub capabilities could be made available to reduce costs and support recipient education on operational and regulatory/legal requirements.
2. **Virginia Energy could develop materials and conduct outreach tailored to local governments and public entities to support DER adoption--building on existing ESPC and DR programs--** including model solar PPA templates and FAQs and DER PPA/procurement training sessions. This could include creating a recognition system to incentivize Virginia localities to adopt DER-friendly ordinances.

Recommendation 9: Modernize DER Interconnection Policies

Finding: Virginia’s DER interconnection rules have not been comprehensively updated, creating barriers to the deployment of new DERs and the participation of DERs in programs and markets. This adversely impacts DER project costs, timelines, customer participation, utility operations, and the pace of adoption for both well-established and emerging distributed technologies.

These recommendations build on Virginia's recent efforts to develop improvements to Commonwealth’s interconnection rules, including the 2023/24 SCC DER Interconnection Working Group⁹⁷ process that addressed a variety of acute, specific issues such as material modification language, dispute resolution, and insurance requirements.

⁹⁵ Energy Commission of Virginia 2026 Workplan (June 2026). <https://dls.virginia.gov/commissions/eur/files/2026-Work-Plan-Approved.pdf>

⁹⁶ Demand Response, Virginia Energy, <https://www.energy.virginia.gov/energy-efficiency/demand-response.shtml>; Energy Savings Performance Contracting, Virginia Energy, <https://energy.virginia.gov/energy-efficiency/performancecontracting.shtml>.

⁹⁷ Case Nos. PUR-2022-00073 and PUR-2023-00069

However, this effort did not address underlying structural problems: Virginia’s DER interconnection requirements are split across two administrative chapters (314 and 315⁹⁸), lack specificity for review of smaller DERs other than NEM solar PV installations, and includes base rule provisions that are more than 20 years old (which did not account for technologies like distributed storage). Under Virginia’s current administrative rules, the interconnection of DERs that participate in net metering or qualify as small agricultural generators is governed by Chapter 315. The interconnection of all other state-jurisdictional DERs is governed by Chapter 314. This has resulted in many behind-the-meter projects being subject to Chapter 315, which has limited provisions related to utility interconnection and thus grants utilities broad discretion over the process through tariffs that do not require approval by the SCC. This disconnect creates a lack of clarity on what rules apply to which types of DERs (whether in NEM or not) and increases administrative complexity, with inconsistencies present across chapters (e.g., there is inconsistent references of IEEE 1547-2003/1547-2018 across 20VAC5-315-40(A)(4) and 20VAC5-314-40(D)(3) and 20VAC5-314-60(A)). In other states, a lack of clear utility requirements has contributed to excessive costs, project delays, inconsistent utility practices, and uncertainty regarding the treatment of energy storage systems.⁹⁹

There are several model interconnection regulations that inform DER interconnection policies nationally, including procedures developed by the National Association of Regulatory Utility Commissioners (2003), the Mid-Atlantic Demand Resource Initiative (2005), FERC (2005), and IREC (2005). IREC’s *Model Interconnection Procedures* the only regularly updated procedures in the country, leading several states (e.g., DE, ME) to cite this resource in statute. As highlighted in the *Freeing the Grid* report,¹⁰⁰ Virginia’s interconnection rules are out of alignment with national best practices, scoring a “C” grade in the most recent scorecard. This highlights the opportunity for continued DER interconnection modernization.

A specific topic raised during Task Force discussions covered utility Direct Transfer Trip (DTT) requirements that currently apply for systems >250 KW in Dominion territory and >200 KW in APCo territory. On November 15, 2024, Dominion Energy Virginia (Dominion) filed a petition with the SCC to revise its terms and conditions for interconnecting distributed energy resources (DER)¹⁰¹. The SCC issued a final order in the case on February 5, 2026, finding Dominion’s screening criteria and DTT requirements reasonable “on a preliminary basis,” but directing the company to continue allowing DTT as an optional requirement for systems >250 kW while requiring Dominion to submit, by November 5, 2026: (1) at least one additional screening criterion beyond the 3:1 light-load-to-generation-ratio (LTGR) screen; (2) a more robust analysis of the 250 kW threshold for use of the 3:1 LTGR screen and the extent to which that threshold could be increased; and (3) any necessary revised terms and conditions for DER interconnection.

Statewide, Virginia’s school solar installations were noted as falling from 40 schools in 2023 to 3 in 2024, coinciding with the timeline of Dominion’s DTT requirements and highlighting the potential impacts of these requirements on DER adoption.¹⁰² Comments submitted through the Task Force from the

⁹⁸ Note: Under Virginia’s current administrative rules, the interconnection of DERs that participate in net metering or qualify as small agricultural generators is governed by Chapter 315. The interconnection of all other state-jurisdictional DERs is governed by Chapter 314. This has resulted in many behind-the-meter projects being subject to Chapter 315, which has limited provisions related to utility interconnection and thus grants utilities broad discretion over the process through tariffs that do not require approval by the SCC.

⁹⁹ See *The Interconnection Bottleneck: Why Most Energy Storage Projects Never Get Built*, Clean Energy Group, 2023. Available at: <https://www.cleangroup.org/wp-content/uploads/Interconnection-Bottleneck.pdf>.

¹⁰⁰ See <https://freeingthegrid.org/virginia/>.

¹⁰¹ *Petition of Virginia Electric and Power Company, For approval of revised Terms and Conditions applicable to interconnection customers and net metering customers*, Case No. PUR-2024-00211, Final Order (Va. State Corp. Comm’n Feb. 5, 2026).

¹⁰² Generation180. *Brighter Future 2026* (Sept 2026). generation180.org/wp-content/uploads/Brighter-Future-Report-2026.pdf

Distributed Solar Alliance suggested additional load-based penetration-test models as an alternative to the 3:1 screen; an SCC-led evaluation of mandatory inverter ride-through and grid-support utilization as an alternative basis for relaxing DTT/telemetry/SCADA requirements on smaller interconnecting systems; a SCC ombudsman function; and near-term requirements for utility to publish hosting capacity maps and constrained-circuit analysis.

Multiple stakeholder also raised the opportunities for flexible interconnection of storage resources and the implementation of meter socket adapters to streamline storage interconnection as high priority areas to support quick, cost-effective expansion of distributed battery deployments.

The four sub-recommendations below are intended to close both the structural gaps to modernize Virginia's DER interconnection policies as well as implement targeted, straightforward changes that achieve near-term improvements in the time and costs of DER interconnection. Specific solutions related to energy storage interconnection are also included.

Sub-Recommendation A: Implement targeted, near-term reforms to modernize Virginia's interconnection procedures through alignment with the IREC *Model Interconnection Procedures*.

This recommendation is aligned with the Task Force's statutory directives to make recommendations on modernizing standards in compliance with IEEE 1547-2018 and UL 1741¹⁰³ (Directive 3), and harmonizing Virginia's interconnection and retail frameworks with PJM's FERC Order 2222 compliance plan (Directive 4), which carries its own February 1, 2027 deadline for Commission action.

Actions could include:

- Led by the SCC within an existing or new DER interconnection Docket, Chapter 314 should be modified to align with the latest IREC *Model Interconnection Procedures*.¹⁰⁴ Key provisions that should be updated in the near term - sequenced with the existing TIIR filing requirement under Case No. PUR-2023-00069 (due June 2027)- include:
 - An expedited review process for DERs with a nameplate rating of 50 kW or less and an export capacity of 25 kW or less that includes transparent, modern screening criteria and appropriate timelines for both applicants and utilities;
 - Clearly defined methods that are acceptable for limiting export below the nameplate rating of the DER that are based on recognized standards, such as UL 3141 and UL 1741 CRD;
 - Elimination of liability insurance requirements for inverter-based DERs with a nameplate rating of 1 MW or less; and
 - Clarification that customers are not required to install a utility-accessible disconnect switch for certain inverter-based DERs.

¹⁰³ IEEE 1547 and UL 1741 specify how smart inverters and batteries must physically behave and be certified. IEEE 1547-2018 introduces mandatory smart inverter functions—such as voltage ride-through, reactive power support, and interoperable communications protocols. UL 1741 is the testing standard certifying that inverters reliably perform these IEEE 1547-2018 functions.

¹⁰⁴ One detail that would need attention in such a transition is consideration of topics that are included in Chapter 314 and Chapter 315 that are not addressed in the most current publications from IREC or FERC. This includes coordination with affected systems, cybersecurity, and the distribution cost sharing program. Any initiative advanced through this recommendation should clarify that topics that are already adopted in Virginia and not in the current scope of that resource are not eliminated during the alignment process.

- Harmonize requirements across Chapters 314 and 315 related to IEEE 1547 standards (as interim near-term fix until broader streamlining and consolidation).
- State statute could be amended to require Chapter 314 (and Chapter 315 if not yet consolidated) be reviewed and updated on a regular basis, based on the publication date of subsequent editions of the IREC *Model Interconnection Procedures* and/or IEEE Standard 1547.

Sub-Recommendation B: Establish a Unified Interconnection Framework for All State-Jurisdictional DERs, consolidating and streamlining rules currently spread across Chapters 314 and 315.

To support long-term success as DER markets expand in Virginia, all of the rules regarding DER interconnection should ultimately be unified under Chapter 314, leaving Chapter 315 to be dedicated to Net Energy Metering. These could be initiated by the General Assembly and some changes may be able to be acted on by the SCC without additional statutory changes (additional analysis would be needed to verify).

Actions could include:

- Eliminate the exemption in Chapter 314 for DERs that participate in net metering or qualify as small agricultural generators (20VAC5-315-10);
- Remove interconnection provisions currently contained in Chapter 315, including 20VAC5-315-70 and portions of 20VAC5-315-40 and 20VAC5-315-75; and
- Reassign the distribution cost sharing program provisions from Chapter 315 (20VAC5-315-100) to Chapter 314.

Any consolidation of Chapter 315 into Chapter 314 should explicitly carve out and preserve net-metering protections in Chapter 315—specifically its no-fee structure, load-based sizing caps, and statutory program eligibility rules under § 56-594 of the Code of Virginia. Clarifying these exemptions ensures that procedural standardization under Chapter 314 does not inadvertently subject net-metered customers to commercial application fees or disturb their core statutory rights.

Sub-Recommendation C: Implement Flexible Interconnection Pathways for Energy Storage Resources

Within an existing or new DER interconnection Docket, Chapter 314 should be modified to allow for flexible interconnection of energy storage resources. These changes should not require legislative action and are within the SCC's existing authority; supportive legislation could be pursued if needed to direct the SCC to act in the near-term.

Actions could include:

- The SCC directs the state's utilities to develop a pilot program that streamlines interconnection of energy storage systems by basing interconnection review on the export and import schedules of the DER. For the screening processes for small, behind-the-meter batteries, this requires using these schedules to determine relevant minimum load. For the engineering studies used to evaluate larger, front-of-the-meter batteries, this requires conducting impact studies based on time series loading data and ensuring loading or hosting capacity data are available for customer use when designing the storage installation.

Sub-Recommendation D: Establish clear pathways for Meter Socket Adapters to support energy storage interconnection.

Within an existing or new DER interconnection Docket, Chapter 314 should be modified to establish clear standards and timelines for the approval and use of meter socket adapters (MSAs) to streamline interconnection of energy storage systems. These changes should not require legislative action.

Actions could include:

- Establish a transparent utility process for the review and approval of meter socket adapters used in conjunction with DERs.
- Advance the use of nationally recognized standards for meter sockets, including UL 414, as the foundation for utility review of meter socket adapters and associated safety requirements.
- Establish reasonable timelines for utility review of meter socket adapter applications and require utilities to provide written justification when approval is denied.

See Appendix E for additional detail and examples of how the above sub-recommendations could be implemented, including references to Virginia statute and examples from other states.

Recommendation 10: Remove Barriers to Electrification

Finding: The Task Force highlighted energy efficiency¹⁰⁵ as an important lever to improve household affordability, a key decarbonization tool, and a core building block of VPP deployment. However, the cost of electrification to the individual homeowner can be prohibitive; when a residential customer adds new electric loads, they often must upgrade their utility service from 100 amperes (“amps”) to 200 amps. Depending on the home, this can cost many thousands of dollars and take months to schedule, preventing customers from adopting the most modern, efficient electric devices. In addition, Virginia's current interconnection framework and cost-allocation rules are built around the generation side of DER interconnection (solar, storage) and do not extend equivalent treatment to new distributed EV chargers, heat pumps, and similar electrification-driven demand. As electrification accelerates and new load triggers the same kind of costly, time-consuming distribution upgrades that generation interconnection faces, the Commonwealth risks reduced adoption absent a comparable cost-causation or cost-sharing framework to allocate those costs fairly between the interconnecting customer and the broader ratepayer base.

Actions include:

1. **The Virginia Energy DER Working Group should explore options to establish flexible service connection pathways for new loads**, allowing new load to connect without a full infrastructure upgrade, thereby reducing upfront cost. This could be enabled through customer use of an Underwriters Laboratory (UL)-listed power control system to manage their load, so that grid planners and operators can trust that the customer will comply with a flexible service agreement.

¹⁰⁵ Energy efficiency includes static energy saving measures such as insulation, windows, and air sealing in addition to technologies such as electric HVAC and cooking equipment that use energy more efficiently than traditional fossil energy-based appliances. The Task Force notes that FERC considers static measures DERs, and these resources play a crucial role in reducing household energy burden and energy demand grid-wide. However, this recommendation focusses on interconnection of dispatchable energy efficiency DERs, such as electric appliances paired with smart thermostats.

2. **The Virginia Energy DER Working Group should explore cost-effective alternatives to traditional service upgrades.** In cases where ratepayers will bear all or part of the costs of an upgrade (including upstream infrastructure), Virginia should consider using federal or state funds to help customers adopt technology (such as UL-listed power control systems) that can make the service upgrade unnecessary.

Recommendation 11: Enhance Customer Education and Outreach

Finding: There is significant work to be done to improve public education, awareness, and consumer confidence around DERs across the Commonwealth. Awareness remains uneven—particularly among Spanish-speaking, low-income, rural, and non-homeowning customers—and technical, utility-specific messaging can be fragmented, inconsistent, and difficult for customers to navigate. Industry stakeholders noted that customers respond most clearly to practical benefits, including lower or more predictable bills, backup power, resilience, and energy independence, rather than technical VPP terminology. As retail DER deployment grows, Virginia should also anticipate risks of misleading sales claims, predatory market actors, inadequate long-term vendor service, and customer confusion about costs, savings, data use, dispatch of customer equipment, and opt-out rights. These risks can erode consumer trust in individual projects and in DER programs more broadly. Task Force members and stakeholders emphasized that visible successful projects, trusted local messengers, clear customer terms, and a reliable permitting/interconnection experience are necessary to build durable confidence and must be done in collaboration between the Commonwealth government, utilities, and industry. New York’s use of a state energy office for consumer-facing tools and program implementation was noted as a relevant model.

Specific ideas raised for improved customer education and outreach included:

- Create a neutral, multilingual one-stop enrollment and information process for DER and VPP programs, with clear explanations of eligibility, expected costs and savings, incentives, participation terms, and available assistance. The state should help legitimize and simplify enrollment while utilities and vendors conduct outreach.
- Use trusted local messengers—such as schools, local governments, Farm Bureau, community organizations—to deliver practical, community-specific education and showcase visible demonstration projects. Establish community grants for trusted local community organizations to educate residents on how to access community solar and storage and lower energy costs through aggregation, prioritizing underserved and Spanish-speaking populations.
- Establish standardized consumer disclosures for DER and VPP offers (e.g., compensation, dispatch and battery-reserve rules, data-sharing practices, fees, duration, customer control, and opt-out rights) with Virginia’s utilities.
- Strengthen sales-practice and vendor-accountability protections (e.g., licensing standards for solar sales representatives, accessible complaint-resolution channels).
- Require state-supported programs to include accessible outreach and enrollment pathways for renters, low-income households, multifamily residents, rural communities, and customers with limited English proficiency.

Recommendation: Develop a coordinated, customer-centered DER and VPP education, outreach, and protection framework. State-led efforts could be driven by Virginia Energy—building on existing VE Connect and customer outreach efforts—in coordination with the SCC, utilities, consumer advocates,

local governments, community partners, and DER providers. A coordinated statewide approach can improve consistency while allowing outreach to be tailored to communities and customer needs.

Actions could include:

1. **Virginia Energy could develop and promote clear, accessible DER and VPP communications tools and outreach campaigns in coordination with utilities and industry**, building on the existing VE Connect program; this could include consolidating DER and VPP messaging under a single, Virginia-recognizable brand across Dominion, Appalachian Power, and co-ops to extent feasible. This could include identifying and working with trusted local community organizations.
2. **Virginia Energy can continue implementing robust consumer protection guidelines and vendor registration frameworks** to ensure DER and VPP adoptions continues effectively and safely for consumers.

Recommendations Summary and Additional Considerations

The eleven recommendations outlined above reflect the Task Force's assessment that DER adoption and market participation are mutually reinforcing and must be advanced together to achieve impactful scale. Expanding the base of deployed DERs creates the resource pool aggregation depends on, while durable compensation, interconnection, and data-access frameworks make that expansion economically viable for customers. Taken as a set, the recommendations give Virginia a sequenced roadmap, spanning immediate SCC dockets and capacity building through medium- and long-term legislative and regulatory action, for building the institutional capacity, market rules, and adoption incentives needed to scale DERs and VPPs statewide.

Beyond these recommendations, the Task Force also raised a few additional topics that were not developed into standalone recommendations but that the Task Force believes warrant continued attention as implementation proceeds:

- **Supporting workforce development:** Virginia will need thousands of additional skilled workers over the next decade to build the DER capacity contemplated under the Virginia Energy Plan, and existing training pipelines will need to scale statewide, with rural and coalfield regions particularly underserved. Task Force members and industry stakeholders noted opportunities to pair DER market deployment with expanded workforce pipelines, apprenticeships, and community-college training. Virginia Energy should conduct or commission a workforce needs and gap assessment focused on DER technologies under the Commonwealth's existing "Clean Energy Workforce Programs (CEWP)" umbrella, translating findings into targeted training pathways through CEWP partnerships with apprenticeship programs, community colleges, and technical schools.
- **Continuing to advance permitting improvements:** Inconsistent application requirements and lengthy, county-by-county permitting processes continue to create unpredictable timelines and add to total system costs for DER projects. The Smart Solar Permitting Platform established under HB 590/SB 382, scheduled to go live in 2027, is expected to begin addressing some of these barriers for residential solar as it becomes integrated as standard practice across the state. Some stakeholders also identified potential changes to the Virginia Existing Building Code

(VEBC) as a further streamlining opportunity.¹⁰⁶ Virginia Energy should continue its implementation and outreach strategy to support timely, broad adoption of the Smart Solar Permitting Platform, and should identify and support additional permitting-streamlining opportunities as they arise.

- **Focusing on energy efficiency:** As noted in the Virginia Energy Plan, increasing energy efficiency is an important goal of the Commonwealth's and can further enable the goals of this DER plan as reducing energy burden and energy demand grid-wide, and dispatchable energy efficiency assets can serve as DERs themselves.

The Task Force intends for these topics to remain part of its ongoing monitoring and reporting role, carried forward by the internal Virginia Energy working group proposed in Recommendation 3, alongside the formal recommendations above.

5.2 VPP-Enabling Policies Roadmap: VPP Policy Topics Prioritization

Achieving the Task Force's long-term vision for distributed energy resources and virtual power plants will require more than expanding DER deployment. It will require a durable regulatory and market framework through which dispatchable DERs can be aggregated, coordinated, and compensated for providing measurable grid services. As discussed in Section 3, the Task Force's vision is a Virginia energy system in which dispatchable DERs are treated as integral, scalable grid resources and can be fairly compensated when they provide cost-effective services that support affordable, reliable, clean, safe, secure, and resilient power.

This section discusses the process and outputs used by the Task Force to identify and prioritize a preliminary set of enabling policies required to support permanent, scalable VPP deployments in the Commonwealth over time.

To develop a policy roadmap for achieving this long-term vision, the Task Force leveraged a phased market-development approach informed by the Energy Policy Design Institute's ("EPDI") VPP Convergence Project. The Project's VPP Convergence framework begins with the state's energy-system objectives, identifies the grid services needed to support those objectives, and then considers the specific VPP configurations that can provide those services cost-effectively. Under this approach, the intent of VPP policy development is not simply to deploy more, bigger DER aggregations, but rather is a framework for enabling DERs and their aggregations to provide cost-effective grid services—such as capacity, peak-demand reduction, energy, local distribution support, and, over time, ancillary services—where those services advance Virginia's broader energy objectives.

The state's VPP policy roadmap is thus a sequenced journey from Virginia's current collection of DER programs and policies toward a more complete market framework in which multiple types of VPPs can operate. It does not assume that every technology, VPP business model, or grid service must be enabled immediately. Instead, it identifies the most consequential near-term VPP applications, focuses initial policy work on the rules needed to make those applications viable, and preserves the ability to expand the framework as technologies, customer needs, utility planning practices, and PJM market opportunities evolve.

¹⁰⁶ "Virginia Distributed Energy Resources White Paper: From Fragmented Policy to Integrate System Design: A Roadmap for an affordable, Resilient and Fully Utilized Distributed Grid," Appendix C, Virginia Distributed Solar Alliance, July 2026.

This approach recognizes that permanent, scalable VPP programs require a coordinated set of policies, procedures, and systems – such as clear procedures for DER registration, eligibility review, and enrollment; customer protections; dispute-resolution processes; and secure and nondiscriminatory access to customer and grid data. See Appendix D for a full list of the policy topics that have been identified by the VPP Convergence project to enable VPPs.

There are a wide variety of “VPP Types”, and the particular policy topics that matter most are not identical for every type of VPP. A utility-administered peak-shaving program, for example, may require enrollment, dispatch, metering, and utility operations procedures but may not initially require the state to establish rules for participation in PJM ancillary-service markets. By contrast, a VPP seeking to participate directly in PJM capacity markets under FERC Order 2222 requires coordination among the DER aggregator, electric distribution company (“EDC”), and PJM, including state-level procedures that complement PJM’s wholesale-market rules. The value of identifying priority VPP Types is therefore that it enables Virginia to concentrate early regulatory work on the policy topics necessary to launch the most relevant near-term applications, while deferring less urgent issues until they become material to future VPP Types.

In order to identify the most important policy topics for Virginia to focus on in the near-term to further support development towards permanent VPP programs, building on and informed by ongoing and forthcoming state VPP pilots, EPDI led the Task Force through a prioritization exercise to identify what types of VPPs could best help meet Virginia’s near term needs and work in Virginia’s energy market structure.

Step 1: Priority VPP Types were identified. As defined by the VPP Convergence project, a “VPP Type” is the combination of a) the grid service(s) being provided; b) the DER technologies participating in the aggregation; and c) the business model or transaction structure through which the service is procured and compensated. Different VPP types may require different rules, operational interfaces, and compensation structures. Through Task Force discussion and a member homework/prioritization exercise, the Task Force identified initial VPP types that best reflected Virginia’s near-term opportunities, available technologies, grid needs, statutory direction, and implementation feasibility.

The purpose of this exercise was not to declare other VPP types unimportant; it was to identify where focused near-term action could produce the greatest progress toward the Commonwealth’s longer-term market-integration vision.

Task Force members initially identified PJM capacity participation, distribution-level peak shaving, and data-center or large-load demand flexibility as the highest-priority grid-service applications. Behind-the-meter storage emerged as the highest-priority technology category, with front-of-meter distributed storage, managed EV charging, and automated load controls also identified as important near-term resources. In considering business models, the Task Force recognized that utility programs may be among the most readily deployable arrangements in the near term, while direct wholesale participation and third-party aggregation remain important pathways that require their own enabling rules.

As an outcome of this work, three VPP types were identified as initial implementation areas based on the greatest needs in Virginia to reduce peak loads on grid infrastructure, require large load / data centers to utilize DERs given their significant energy needs and stress on current infrastructure, and further open opportunities for PJM capacity market participation to align with FERC Order 2222:

- **Distribution Peak Shaving utility program**

The first priority VPP Type is a utility-administered distribution peak-shaving program. In its basic form, the utility compensates participating DER customers for reducing demand or supplying stored energy during identified system peak periods. Eligible resources could include

behind-the-meter battery storage, managed EV charging, smart thermostats and other automated load controls, and, where appropriate, front-of-meter distributed storage.

The objective is to reduce peak demand and improve use of existing grid infrastructure, potentially avoiding or deferring higher-cost generation, transmission, or distribution investments. This priority type is intentionally framed broadly enough to build on existing utility-program experience while allowing future refinement.

Note that within the Dominion VPP Pilot, several proposed VPP programs are examples of this VPP Type, including: Residential Battery Storage Pilot; Residential EV Managed Charging Pilot; and Non-Residential HVAC for Small & Medium Business Customers

Potential variations of this VPP Type include:

- A program focused on local distribution peaks or identified constraints rather than systemwide peak periods. (e.g. Dominion’s Residential EV Managed Charging Pilot)
- A third-party-aggregator model in which the utility transacts with an aggregation rather than with individual DER customers. (e.g. Dominion’s BYOD Aggregator Access Pilot)

The Task Force discussed these variations but did not fully develop each one as a near-term priority type. As Virginia moves toward locally targeted programs or third-party aggregator models, additional policy topics will need to be addressed, including local capacity valuation, aggregator licensing or qualification, more detailed operational coordination, and more granular data and measurement requirements.

- **Data-center demand flexibility**

The second priority VPP type addresses Virginia’s rapid growth in data-center and other large-load demand. The initial concept is a utility VPP program in which a data center or other large-load customer provides funding for dispatchable DER capacity that can help meet a local capacity need associated with the customer’s demand.

Participating DERs could include storage, flexible load, managed charging, and other dispatchable resources capable of providing capacity in the relevant location and timeframe. The purpose is to reduce infrastructure costs and could be used accelerate or improve the efficiency of large-load interconnection by supplementing conventional grid investments with flexible, locally responsive capacity.

The Task Force distinguished this concept from the demand-flexibility framework contemplated in House Bill 284. The data-center-funded utility-VPP concept is principally an implementation and transaction model: a large-load customer contributes funding to support a utility program that obtains local, dispatchable DER capacity.

By comparison, a demand-flexibility standard or related voluntary program establishes a broader policy framework for flexible demand. The precise structure of payments, obligations, performance requirements, customer participation, and utility responsibilities will require further clarification as policy development proceeds.

A significant potential variation of this VPP Type is a direct contract between a data center and a third-party VPP or DER aggregator, rather than a utility-administered program. Such a model could create a more direct bilateral transaction for flexible capacity or related services. The Task Force did not treat that variation as the initial priority given Virginia’s vertically integrated structure in much of the state, but it remains a potential future pathway. Similarly, local DER flexibility associated with large loads may eventually be used not only to address

interconnection timing but also to reduce congestion-related supply costs, improve local system utilization, or support other locational grid needs.

- **PJM capacity market** (FERC Order 2222 alignment):

The third priority VPP type is the aggregation of behind-the-meter storage and other eligible DERs for direct participation in PJM capacity markets, possible today for many DER types acting as demand response as governed by FERC Order 719,, and 745, and expanding to include grid injecting resources under FERC Order 2222. This pathway would enable an eligible DER aggregator to combine individual resources into a VPP that can bid into PJM’s wholesale market and provide wholesale market services, subject to PJM’s market rules and the necessary state and EDC procedures.

This VPP type was initially treated as a high priority because of both the Task Force’s statutory direction to support FERC Order 2222 compliance and the potential for DER aggregation to provide ratepayer benefits through participation in regional wholesale markets. However, Task Force discussion and input from prospective aggregators indicated that direct PJM participation for some DER assets (e.g. residential assets and those that inject to the grid but are net metered) may not be commercially attractive in the immediate term under the current PJM construct. No DER aggregation resources bid into PJM’s 2028/2029 Base Residual Auction under the FERC Order 2222 model. DERs continued to participate as DR and ESR resources.

For these reasons, the Task Force’s near-term recommendations focus on ensuring Virginia meets the minimum state-level requirements needed for Order 2222 implementation, while continuing to support traditional DER participation in demand response programs. Relevant actions for harmonizing the Commonwealth with Order 2222 include establishing procedures for DER registration, EDC review, EDC-aggregator operational coordination, data access, customer protections, dispute resolution, dual participation, and other state-level processes that will allow eligible aggregators to register, bid, and perform once PJM’s participation pathway becomes operational.

The Task Force’s Order 2222 recommendations—further discussed in Section 5.3 below and summarized in Recommendation 5—should therefore be presented as a distinct but connected roadmap. They are intended to move Virginia beyond last-minute compliance and toward a framework that gives aggregators sufficient clarity to evaluate participation in future PJM capacity auctions. At the same time, as noted by Task Force members and stakeholders, the Task Force acknowledges that immediate customer and grid value may be available through existing PJM demand response programs and state-level utility-administered peak-shaving and local-capacity programs while PJM’s rules, economics, and implementation processes mature.

The Task Force also recognizes that recent events in PJM have opened pathways to VPPs providing PJM grid services without directly bidding into PJM markets (e.g., Peak Shavings Adjustment). As of the writing of this Report, the Task Force has not had the time to develop recommendations related to these pathways, but are further discussed as an area to evaluate (see Recommendation 2).

These priority VPP types should be understood as initial implementation priorities, not as an exhaustive list of the VPPs Virginia should permit or pursue over time. The Task Force discussed future applications including local non-wires alternatives, third-party aggregation for distribution-level services, utility-controlled DER models, vehicle-to-grid applications, direct large-load-to-aggregator contracts, and

additional wholesale-market services. Those models may become appropriate as Virginia develops the related policy infrastructure and as market conditions evolve.

Step 2: Priority policy topics were identified to enable these VPP types. Leveraging these insights and informed by Task Force and stakeholder input, EPDI identified the priority policy topics that need to be addressed to enable these priority VPP Types. Topics were evaluated according to their importance to enabling the selected VPP applications. This allowed the Task Force to distinguish between Tier 1 policy topics that need early attention and other topics that will become more important as Virginia pursues more advanced VPP models, additional technologies, or additional grid services.

Fourteen policy topics were identified as Tier 1 topics for Virginia to address, including topics like DER registration, customer data access, and dispatch override. These topics cover the full lifecycle of a VPP program—from initial setup and registration, through deployment and operation, to market transactions and utility financial treatment.

Step 3: The current state of Virginia’s work across these priority policy topics was evaluated to better understand the foundation for where Virginia is on these topics. For each priority policy topic, EPDI assessed the Commonwealth’s current policies, proceedings, utility practices, and active discussions based on Task Force member and utility input (particularly with context from Dominion to align work with their ongoing VPP pilot) and review of recent regulatory proceedings. The purpose of this “state of the state” assessment was to determine what rules, procedures, systems, or institutional processes already exist; what is being addressed through the Dominion VPP pilot or other efforts; and what remains to be developed for durable VPP implementation.

The preliminary assessment conducted by EPDI found that Virginia’s existing policies and procedures are generally not yet sufficient to support viable permanent VPP programs at scale outside of pilot contexts. There are relatively few VPP-specific enabling policies being actively developed in regulatory dockets or programs beyond the Dominion pilot, with most efforts for Tier 1 policy topics being program-specific rather than statewide .

Virginia has important building blocks for DER deployment and early-stage VPP activity, but does not yet have the integrated statewide policy, procedural, and systems framework needed to support durable, scalable VPP participation outside discrete utility programs and pilots. The Commonwealth has established a foundation through net energy metering, shared solar, demand-side management programs, statutory storage targets, recent DER and grid-utilization legislation, and Dominion Energy’s authorized VPP pilot. However, these initiatives were generally developed for distinct purposes and do not yet constitute a common enabling statewide policy framework. The table below includes a brief preliminary summary of the current state of development in Virginia across identified Tier 1 policy topics.

Dominion’s VPP pilot is an important near-term testing ground and can inform statewide VPP policy and program design and practices. The pilot, however, should not be treated as the sole or final set of VPP Types for Virginia. Establishing clear statewide policies for several issues is necessary to support broader VPP deployment at scale—such as defining direct third-party data access, standardized operational protocols, consumer protections, dual-participation rules, and common metering and settlement practices. .

Step 4: The next meaningful policy topic milestone for Virginia to achieve to enable viable VPP deployment was identified. For each Tier 1 policy topic, EPDI identified the next practical regulatory advancement needed to enable the priority VPP types, which then formed the basis for recommendations to move forward on the roadmap to achieve the Task Force’s long-term vision. Notably, the roadmap need not specify the entire future of a policy topic; rather, it identifies the next decision, procedure, system, filing, or stakeholder process needed to move Virginia materially closer to implementation.

To enable viable near-term VPP deployment, Virginia does not need to resolve every issue associated with a mature, fully interoperable DER market. It does, however, need to establish a minimum statewide VPP-enabling framework that replaces today’s largely program-specific practices with consistent rules, procedures, and systems for customer enrollment, DER registration, secure data exchange, aggregator participation, operational coordination, dispatch, measurement, settlement, and utility cost recovery. Building on the VPP Convergence project framework, a preliminary assessment of Virginia’s minimum viable policy levels was identified. This framework can help support the development of the Task Force’s initial priority VPP types—particularly utility peak-shaving programs and data-center-funded local-capacity programs—while also establishing a foundation for broader VPP models and eventual wholesale-market participation.

Note: The next milestones needed to enable the PJM Capacity Market participation VPP Type in line with FERC Order 2222 is covered in Section 5.3.

Current State and Minimum Viable Policy Levels for Peak Shaving and Data Center VPP Types
(see Appendix D for more detailed descriptions)

Policy topic	Current-state assessment	Minimum Viable PRL
DER enrollment in VPP programs — Standard process for registering VPP DERs and giving EDCs reliability-related visibility	No statewide rules; processes are program-specific. Dominion is developing procedures aligned with PJM timelines.	Each utility has standardized process for DER enrollment in VPP programs including eligibility, DER information, review, and response timelines.
Customer data access — Customer-authorized access to account, billing, interval, and DER data	No current VPP-specific framework. Dominion pilot relies on an implementation vendor rather than direct third-party access; shared-solar rules are the closest precedent.	EDC data-exchange platform using Green Button Connect My Data, with customer-controlled authorization and standardized, secure data sharing.
Third-party data access to customer data — Aggregator/Operator onboarding and common data content/quality standards	No standard onboarding, data fields, data history, or data-quality requirements.	Prompt, reasonable third-party vetting and access; provide at least 24 months of standardized interval, billing, tariff, account, and quality-flag data.
Customer protection for VPP participation — Informed consent, transparent terms, customer choice, and exit rights	No VPP-specific rules; existing solar, shared-solar, and general consumer protections may apply indirectly.	VPP enrollment rules requiring clear disclosures, affirmative consent, dispatch and payment terms, data permissions, and withdrawal rights.
Dispute resolution — Process for resolving enrollment, data, dispatch, performance, and payment disputes	No VPP-specific EDC-aggregator process. Interconnection procedures exist; Dominion’s	Statewide dispute process for EDC-aggregator matters; also cover EDC-data-center disputes over VPP funding or capacity credits where applicable.

	pilot is developing dispute resolution procedures.	
Interconnection — Physical DER connection and operating requirements	Context and recommendations addressed separately in Recommendation 9; existing interconnection processes remain foundational to VPP participation.	Ensure BTM storage resources are allowed to export energy and count exported energy towards performance in VPP programs
Cybersecurity — Secure EDC–aggregator communications and third-party customer-data exchange	Utilities must develop DER cybersecurity standards and implementation plans, but no VPP-specific interface rules exist.	Baseline cybersecurity rules for EDC–aggregator operations and EDC–third-party data access, including authentication, encryption, access controls, and incident response.
EDC–aggregator operational coordination — Operational notices, real-time communications, and reliability coordination	No statewide requirements; procedures are program-specific. Dominion’s pilot is the principal active example.	Standard real-time coordination protocols covering contacts, notices, outage/emergency communications, data exchange, and escalation.
Dispatch override — Conditions under which an EDC can limit or override VPP dispatch for safety or reliability	No regulations. Dominion is developing FERC Order 2222-related procedures; retail VPP programs have not yet addressed the issue.	Rules defining permitted override conditions, EDC–aggregator communications, documentation, restoration of normal dispatch, and compensation effects.
Grid-service mechanisms — Ways to procure and compensate DER services such as peak reduction or local capacity	Authority and program design are addressed case by case through existing DSM or related mechanisms; no general framework exists.	For peak shaving, standardized utility-program design is sufficient. For data centers, include load-interconnection tariff provisions for contracted capacity and upgrade-cost or capacity benefits.
Metering and performance measurement — Measurement and verification of delivered VPP service	No VPP-specific metering rules; submetering and device-level metering remain unresolved, with no active regulatory discussion identified.	Permit validated submetering/device-level metering where needed and establish minimum measurement, baseline, validation, and audit rules.
Transaction settlement and settlement data — Calculation, transparency, correction, and payment of VPP compensation	No identified VPP-specific settlement framework or standards for data access, quality, timing, or corrections.	Standard settlement rules with transparent payment calculations, participant access to supporting data, correction procedures, and data-quality requirements.
Dual participation — Participation in more than one program or market without double compensation or conflicting dispatch	No VPP-specific rules at state level, but PJM has controls against double counting; existing NEM and DSM rules are presumed to apply. Dominion is developing a program/tariff matrix.	For peak-shaving VPPs, require a utility-maintained matrix identifying permitted and prohibited combinations. No additional PJM-focused rule is needed for local-capacity data-center VPPs (because the VPP is just operating at the retail level in this example).
Cost recovery for VPP infrastructure — Recovery of prudent utility investment in VPP systems, platforms, and operations	Addressed program by program through DSM or grid-transformation proceedings.	Transparent cost-recovery pathway for justified VPP-enabling investments, tied to customer value, performance metrics, and regulatory review.

These policy topics and minimum policy readiness levels represent a preliminary assessment conducted by EPDI as part of the DER Task Force effort to unlock near-term VPP deployments. These could be further validated and refined through further development of statewide VPP-enabling policies, as noted in *Section 5.1 (Recommendation 3: Establish VPP-Enabling Policies)*.

5.3 FERC Order 2222 DER Aggregation Roadmap

HB 285 / SB 223 also requires the Task Force's final report to include a roadmap to harmonize the Commonwealth's retail frameworks with PJM's plan for compliance with FERC Order 2222, including to support SCC action by February 1, 2027.

PJM's implementation of FERC Order 2222 will occur through its DER Aggregator Participation Model, which allows a DER aggregator to combine eligible individual resources and participate in PJM wholesale markets as a supply-side resource. FERC regulates PJM's wholesale-market tariffs, participation rules, and performance requirements; aggregators participating under this model are wholesale-market participants. The purpose is to allow collections of smaller DERs that could not efficiently participate individually to provide capacity, energy, and, over time, other wholesale grid services.

PJM's market rules alone, however, cannot enable DER aggregation in Virginia. FERC explicitly leaves several DER aggregation rules to the SCC (e.g., interconnection, customer data access). The SCC and Virginia EDCs retain authority over retail and distribution-system matters, including interconnection, customer-data access, and EDC review of proposed DER aggregations for distribution-system safety and reliability.

Order 2222 does not create a VPP program, set a payment level, or require every DER to participate in wholesale markets. Rather, it requires PJM and other RTOs/ISOs to create a participation pathway for eligible DER aggregations. The Order also recognizes that state and local authorities retain jurisdiction over the retail-level and distribution-system matters that affect DER participation. As a result, successful implementation requires coordination among three distinct parties, as shown in Figure 7.

- **FERC and PJM:** Establish the wholesale-market participation model, eligibility requirements, market rules, bidding rules, and performance obligations for DER aggregations
- **Virginia SCC and state policymakers:** Ensure that state retail, interconnection, consumer-protection, and utility-regulatory frameworks do not unnecessarily prevent or conflict with wholesale DER aggregation
- **Virginia EDCs and DER aggregators:** Establish practical processes for registration, information exchange, distribution-system review, operational coordination, dispatch communications, data access, and dispute resolution

Figure 7: PJM's Relationships

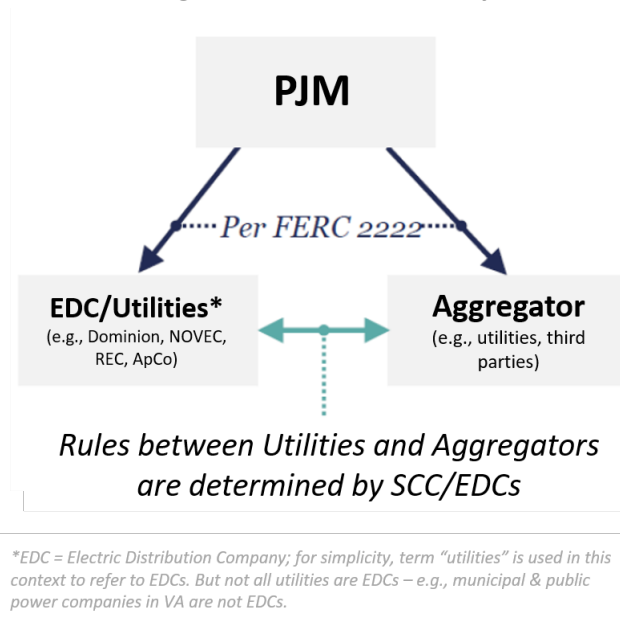


Figure 7: PJM's Relationship with EDC/Utilities and Aggregators per FERC Order 2222

Virginia policies and regulations play an important role in enabling DER aggregations to participate in PJM wholesale markets under FERC Order 2222. While Virginia cannot resolve issues within PJM's jurisdiction, Virginia can establish the state-level framework needed to make future PJM participation practical for Virginia-connected DERs. This can include supportive state-level procedures for registration, data sharing, EDC–aggregator coordination, dual participation, dispatch override, and dispute resolution. Without these rules, aggregators will face uncertainty and practical barriers even when PJM permits participation.

Beyond harmonizing Virginia's rules with FERC Order 2222 compliance per the statute's Task Force, this work is directly relevant to enabling the third priority VPP type of aggregated behind-the-meter storage participating in PJM capacity markets as discussed in Section 5.2.

Virginia (SCC, utilities) must establish supportive policies and programs in order to unlock one of Virginia's priority VPP types and to enable DERs to participate in PJM effectively under FERC Order 2222 (providing services beyond traditional demand response).

Following the same process for identifying critical policy topics and evaluating the current state and minimum viable policies as laid out in Section 5.2, six state and utility-level policies were identified by EPDI as Tier 1 policy topics. These six policy topics are where actions need to be accomplished prior to full PJM implementation of FERC Order 2222 and are not dependent on PJM. These are listed in the table below, along with a minimum policy readiness levels so Virginia can be prepared for the participation of DER aggregations in PJM markets.

Overall, significant work on Implementing FERC Order 2222 in Virginia is in early stages. The SCC has not initiated any proceedings on FERC Order 2222 topics, with most compliance implementation currently up to Virginia utilities individually. Dominion, for example, has noted that they will have procedures in place by November 2027. Information on these procedures is not yet publicly available. In addition, the Virginia utilities are awaiting final market and operational rules from PJM.

Summary of Policy Topics required for FERC Order 2222 compliance, current state assessment across these, and minimum viable next step for Virginia to align with FERC Order 2222 requirements

Current State and Minimum Viable Policy Readiness Levels for PJM VPPs

Policy Topic and description	Current state	Minimum Viable PRL
Dispute resolution — State-level process for resolving disagreements over DERA registration, reliability findings, coordination, dispatch overrides, and participation requirements	No regulations have been defined around FERC Order 2222 dispute resolution. Dominion is identifying potential dispute pathways as part of its pilot. Existing SCC processes, interconnection-dispute procedures, and the dispute provisions under development for Dominion's BYOD aggregator program offer useful starting points.	Add on to existing dispute resolution procedures, rules for new FERC Order 2222 disputes, especially dispatch overrides and operational coordination.
Interconnection — Ensures export-capable DERs have interconnection rights and technical approval to provide PJM wholesale services through a DERA	;See recommendation 9 for interconnection assessment; existing interconnection rules are the starting point for export-capable DER participation.	SCC regulations include DER interconnection study processes and agreements that permit export and allow configurations that can be measured and compensated for PJM market services
DERA registration and EDC review — EDC review of individual DERs seeking to join a PJM DER aggregation, including capability, safety, and reliability considerations	Dominion is developing processes for PJM's 15-day capability and 45-day safety/reliability reviews.	Utilities have established transparent review criteria and procedures consistent with the FERC/PJM 60-day maximum timeline.
Operational coordination — Operating-day communication and information sharing among EDCs, DER aggregators, and PJM when distribution conditions affect DER availability or output	Dominion is developing coordination processes and has identified potential value in a new rulemaking.	Each utility has implemented SCC approved rules and procedures on real-time communications, notification timing, operational workstreams, and documentation.
Dispatch override — EDC authority and procedures to override DERA dispatch when necessary for distribution-system safety or reliability	Dominion is developing override procedures and is open to SCC discussion of communications protocols.	SCC regulations allow reliability-based overrides under uniform criteria, with timely notice, clear documentation, and dispute-resolution backstop.
Dual participation — Rules for DER participation in retail programs and PJM markets without double counting the same grid service in the same interval	Dominion is developing a DER Registry rules engine and matrix to identify potential program conflicts.	Establish a statewide participation matrix focused on preventing double counting of the same service in the same interval; separately assess NEM participation in PJM ancillary services.

Additional detail on these topics and other supportive policy actions that could further support FERC Order 2222 implementation are in Appendix D.

As noted in the recommendations above, the key next step to advance these efforts would be an SCC proceeding—or similar statewide effort—to establish the minimum statewide procedures that are necessary for aggregators to understand the rules governing distribution-system participation before they must enter PJM's 2027 market processes.

5.4 Integrated DER Action Plan Summary

Action	Primary Owner	Timeline								Notes
		26 - Q4	27 - Q1	27 - Q2	27 - Q3	27 - Q4	28	29	30+	
Key Ongoing / Existing Milestones (not comprehensive)										
DER Task Force	DER TF	X			X					11/1/26 Recommendation Report Due 7/1/27 Implementation Report Due; TF Sunset
DCAF and EO22 implementation related to data center-supported DER initiatives	CEO	X	X	X	X	X	X	X	X	Ongoing initiative
Dominion & APCo SB 371 Large Load Demand Flexibility	Utilities, SCC		X							1/15/27 filing due
PJM Reliability Backstop Procurement / IRAS Curtailment policies	PJM	Timing in development; likely by mid-2027								
PJM FERC Order 2222 implementation	PJM					X	X			11/1/27 – DER aggregations can register in PJM 2/1/28 – DER aggregations can participate in PJM markets
Dominion VPP Pilot	Dominion, SCC	X				X	X			11/15/26 VPP Tariff proposal due 12/31/27 Electric School Bus program filing 7/1/28 Dominion VPP Pilot end
APCo VPP Pilot	APCo, SCC				X		X		X	7/1/27 ApCo VPP Pilot filing 7/15/28 APCo VPP Tariff filing 2/1/30 APCO VPP Pilot end
Dominion & APCo Grid Utilization Metrics filing	Utilities, SCC	X								10/15 – grid utilization metric filing due
SCC PBR Working Group	SCC				X					7/1/27 PBR Final WG Report due
Smart Solar Permitting Platform	VA Energy				X					7/1/27 implementation date
Income & Age Qualified Solar/Storage/EE Utility Program	Dominion, APCo	X								12/31/26 Utility filing for pilot
Pay as You Save (PAYS) Technical Conference	SCC	X								11/1 Tech Conference deadline
DER Interconnection related filings upcoming	Dominion, APCo	X								11/5 – Dominion DTT supplemental filing 12/1 – Distribution Cost Sharing filing
Jurisdictional Specific Test (JST) used for utility DSM cost-benefit assessments	SCC, utilities							X		2029 – implementation date
IRP Reforms	SCC		X		X					3/1/27 – SCC IRP Working Group report due 9/1/27 – SCC guidelines on IRP implementation due
Federal Tax Credits	N/A					X			X	12/31/27- Final "placed in service" deadline for 30% credit for commercial solar and resi leases/PPAs. 12/31/32 - Federal phase-down begins for commercial/TPO BESS systems.
Cross-Cutting Initiatives										

Rec 1: Systems Approach with Implementation capacity										
Allocate resources to support expanded Virginia Energy (VE) DER team to spearhead systems-based implementation strategy and cross-stakeholder working groups as needed	GA / Exec Branch (budget; optional supportive legislation)		X							New activity; budget; optional supportive legislation could direct VE DER team and authorize to lead working groups with SCC, utilities, and other stakeholders to deliver on DER vision and roadmap
After TF sunsets, Executive Branch through the VE DER team (if expanded) alongside the CEO to spearhead and coordinate efforts to advance progress towards DER Vision , such as running cross-stakeholder working groups, tracking DER deployment progress, periodically updating legislature; continue to support DER Task Force until sunset	VA Energy*	X	X	X	X	X	X	X	X	Expanded activity; can provide ongoing annual updates to GA, Governor, or others as needed
Rec 2: Data Center Funded Contracts										
Review Dominion & APCo SB 371 demand flexibility submission and proceeding to ensure development aligns with DER deployment goals; monitor and engage in future coop submissions as needed	DER Task Force		X	X						Ongoing initiative
Monitor and engage in near-term PJM activities to support data center contract and market models that advance state DER goals, with particular attention to near-term RBP PSA and IRAS processes	CEO / VA Energy / DER Task Force	X	X	X						Ongoing initiative
DER Market Participation (incl. aggregation into VPPs)										
Rec 3: VPP-Enabling Policies										
Begin establishing common statewide frameworks for key VPP enabling policies , with focus on policies related to data-center funded pathways given near-term, time-sensitive activities.	VA Energy,* CEO Office, DER TF	X	X	X						New activity; depth of action in near-term may depend on VA Staff / Contracting resource availability
SCC opens “DER umbrella docket” —or scope into existing proceedings as relevant—to establish needed enabling rules , aligned with findings from statewide framework activity (above) and under authority from DER Task Force Statute	SCC		X	X	X	X				New activity; possible through existing SCC authority; could be directed from additional GA input if needed
Scope specific policies into existing ongoing dockets or DER Umbrella as needed			X	X	X	X	X	X		New & ongoing activities; see Section 5.1, Recommendation 3 for specific actions
Rec 4: Expand Compensation Frameworks										
Develop VPP compensation framework models and implementation strategy	VA Energy*			X	X	X	X	X	X	New activity; could initiate in 2027 and continue
Rec 5: Implement Minimum Changes to Enable VPP Participation in PJM Markets via FERC Order 2222										
Continue engagement with PJM to advocate for rules / processes that support DER deployment & participation , and establish enabling policies as needed	CEO, VA Energy	X	X	X	X	X	X	X	X	Ongoing activity

Scope into existing proceedings, “DER Umbrella docket”, or standalone FERC Order 2222 proceeding (least preferred to do standalone) to establish needed rules with implementation timeline by Feb 1, 2028 PJM market deadline	SCC		X	X	X	X	X				New activity; See Section 5.3 for detail on which policy topics to address to align with FERC Order 2222
Rec 6: Utility Planning & Ops											
Monitor implementation of PBR Working Group (HB 903/SB 251), Grid Utilization Metrics (HB 434/SB 621), and IRP Reforms (HB 429/SB 249) and engage as needed to ensure resulting proceedings and reporting frameworks remain consistent with their intended DER and VPP planning purposes.	DER Task Force; VA Energy*	X	X	X	X	X	X				Ongoing activity
DER Adoption Related Recommendations											
Rec 7: Reduce Upfront Cost Barriers for DER Adoption											
Provide state funding and expand policies that encourage projects to be developed on previously disturbed lands (e.g., agrivoltaics, brownfields, former mine land), available to projects enrolled in NEM or the Recommendation 4 value-stack program.	General Assembly (budget; policy fixes); VA Energy (implementation)		X (GA)	X	X	X	X	X	X		New / expanded activity
Clarify processes around NEM-plus-storage pathways to address barriers for solar owners to add storage.	Virginia Energy		X	X	X						New / expanded activity
Expand VCEIB budget (or pursue other sources, e.g., if Solar 4 All is reestablished) to offer reduced-interest loans, credit enhancements, or other financing tools tailored to residential- and small-commercial-scale solar and storage	Virginia Energy* / General Assembly		X				X	X	X		<i>Timing flexible; could be introduced and scaled when feasible</i>
Evaluate other state actions to support cost reductions (e.g., tax credits), particularly as federal tax credits end for solar	General Assembly		X				X	X	X		<i>Timing flexible; could consider in 2028 GA cycle</i>
Consider raising the 6%-of-peak-demand net-metering cap before deployment approaches the cap.	General Assembly							X	X		<i>Timing flexible; could consider in future cycle as needed</i>
Continue facilitating bulk or other joint procurement models (e.g., SwitchTogether, Solarize) to reduce costs and promote adoption across the state	CEO / Virginia Energy	X	X	X	X	X	X	X	X		Ongoing existing activity
Rec 8: Support Schools & Public Facilities DER Adoption											
Establish a dedicated school and public-facility DER adoption program, including streamlined interconnection for projects ≤1 MW, streamlined procurement pathways, and additional grants for microgrid/resilience-hub capabilities.	General Assembly		X				X	X	X		New activity; could start in upcoming or future GA cycle
Develop materials and conduct outreach tailored to local governments and public entities, including model PPA templates, FAQs, and training sessions, and create a recognition system for DER-friendly ordinances.	Virginia Energy*				X	X	X	X	X		New activity. Ongoing; timing flexible; could be nearer-term if aligned with legislation/resources; can be timed with other customer education and outreach efforts

Rec 9: Modernize DER Interconnection Policies										
Implement targeted, near-term reforms to align Virginia's interconnection rules with specific IREC Model Interconnection Procedures	SCC (with GA as needed)		X	X						New activity; could initiate by early 2027
Establish a Unified Interconnection Framework for All State-Jurisdictional DERs, consolidating and streamlining rules currently spread across Chapters 314 and 315	SCC (with GA as needed)			X	X	X	X	X	X	New activity; could be initiated in 2027 and implemented over time
Implement Flexible Interconnection Pathways for Energy Storage Resources	SCC (with GA as needed)			X	X	X	X			New activity; could align with and be included as part of the actions noted above
Establish clear pathways for Meter Socket Adapters to support energy storage interconnection	SCC (with GA as needed)			X	X	X	X			New activity; could align with and be included as part of the actions noted above
Rec 10: Remove barriers to electrification										
Explore options to establish flexible service-connection pathways that allow new loads (e.g., EVs, home storage) to connect without a full infrastructure upgrade (e.g., via UL-listed power control systems).	Virginia Energy*				X	X	X			New activity; ongoing assessment; could initiate in late 2027 ahead of 2028 GA
Explore cost-effective alternatives to traditional service upgrades, including need for public funding to help customers adopt technology that can make a service upgrade unnecessary.	Virginia Energy*				X	X	X			New activity; ongoing assessment; could initiate in late 2027 ahead of 2028 GA
Rec 11: Enhance Customer Education & Outreach										
Expand DER/VPP education and outreach tools, building on VE Connect development and other education efforts	Virginia Energy		X	X	X	X	X	X	X	Expanded activity; ongoing
Support consumer education campaigns alongside consumer protection guidelines and vendor registration frameworks	Virginia Energy		X	X	X	X	X	X	X	Expanded activity; ongoing

Appendix

A. Overview of Task Force Members¹⁰⁷

Task Force Roster (16 Members)

- **Chief Josephus Allmond**, Chief Energy Officer, Office of the Governor (**Chair**)
- **Delegate Richard (Rip) Sullivan**, Delegate, 6th District, Virginia House of Delegates
- **Delegate Dan Helmer**, Delegate, 10th District, Virginia House of Delegates
- **Senator Schuyler VanValkenburg**, Senator, 16th District, Virginia State Senate
- **Deputy Secretary Kristin Dahlman**, Office of the Secretary of Commerce and Trade (Designee of Secretary Carrie Chenery)
- **Carrie Hearne**, Director, Energy Commission of Virginia (Designee of Senator Scott Surovell)
- **Emily Orvis**, Vice President of Energy Markets, Voltus, Inc.
- **John Farmer**, Energy Regulatory Attorney, Virginia Office of the Attorney General
- **Lt. Governor Ghazala Hashmi**, Lieutenant Governor of the Commonwealth of Virginia
- **Ashish Kapoor**, Senior Energy and Climate Advisor, Piedmont Environmental Council
- **Richard Caperton**, Vice President of Public Policy, SPAN
- **Tony Smith**, Chair and Co-Founder, Virginia Distributed Solar Alliance
- **Dawn Oleksy**, Clean Energy Manager, City of Richmond
- **Joe Lerch**, Director of Local Government Policy, Virginia Association of Counties
- **Angela Navarro**, President, Align Energy Advisors
- **Bill Murray**, Senior Vice President, Corporate Affairs & Communications, Dominion Energy

B. Summary of Stakeholder Input and Process

Over the course of its work, the Task Force gathered input through a combination of full Task Force meetings, written member homework, one-on-one member and stakeholder interviews, public and industry engagement sessions, a peer-state benchmarking session, and written and verbal comment on the draft and final reports. This section summarizes that engagement and describes how it shaped the findings and recommendations presented in Section 5. Except where a specific written submission or a Task Force member's stated position is quoted directly, verbal input described below is drawn from attendee notes taken during Task Force meetings and stakeholder sessions, not from a recording or transcript.

Stakeholder Engagement Timeline

¹⁰⁷Virginia Energy, Distributed Energy Resources (DER) Task Force, Meeting 1 Materials (July 16, 2026), https://www.energy.virginia.gov/renewable-energy/documents/DER/Meeting%201%20Materials_v1.pdf.

Date	Activity	Format / Participation
Jul. 17 & Aug. 4 2026	Task Force Meetings 1 and 2	Full Task Force; established DER definitions, objectives, and a current-state overview for Virginia, and reviewed synthesized member input from Homework 1.
Aug. 13, 2026	Early stakeholder sessions	Individual sessions with Voltus, Align Energy Advisors, and SPAN to confirm buy-in on emerging ideas ahead of the formal member-interview process.
Aug. 20–25, 2026	One-on-one member interviews	Individual interviews with Dawn Oleksy (City of Richmond), Joe Lerch (VACo), Carrie Hearne (Energy Commission of Virginia), and a meeting with Bill Murray (Dominion Energy).
Aug. 25, 2026	Public Input Session	Public engagement session reviewing the draft vision and preliminary findings; written response also received from the City of Charlottesville.
Aug. 27, 2026	Industry Listening Session	Small-group session with industry stakeholders, including Sunrun, Goodleap, Generac, NRG, Renew, and the Virginia Distributed Solar Alliance (VA-DSA).
Summer 2026	Task Force Homework 1 and 2	Two rounds of written assignments distributed to all 16 members; 8 of 16 responded to Homework 1 and 6 of 16 to Homework 2.
Summer 2026	Peer-state benchmarking session	Briefing from the Massachusetts Department of Energy Resources (MA DOER) on that state's incentive design and interconnection experience.
Sept. 11–15, 2026	Written feedback on the draft interim report	Written comments and redlines from Task Force members Richard Caperton (SPAN), Ashish Kapoor (PEC), Tony Smith (VA-DSA), Angela Navarro (Align Energy Advisors), and Dominion Energy, plus Chair Josephus Allmond.
Sept. 15, 2026	Task Force Meeting 3	Full Task Force discussion of the draft interim report; extensive verbal feedback per attendee notes.
Oct. 13, 2026	Task Force Meeting 4	Full Task Force vote on final recommendations.

Public and Industry Engagement

The Task Force's Public Input Session (August 25, 2026) tested the draft vision and preliminary findings with the public. Attendees generally received the vision well, while asking that it more explicitly address grid resilience and islanding, frame customers as active participants rather than passive recipients, and provide for review beyond the Task Force's statutory sunset. Participants also prioritized modernizing Chapter 314/315 interconnection rules, including for bidirectional EV charging (V2G/V2H) (Recommendation 9); moving compensation beyond net energy metering toward value-stacked, benefit-cost-based models (Recommendation 4); and building a formal lessons-learned process into Dominion's VPP pilot.

The Industry Listening Session (August 27, 2026), with participants including Sunrun, Goodleap, Generac, NRG, Renew, and VA-DSA, surfaced a consistent “time to power” concern: streamlined permitting and

interconnection for already-aggregated DERs, and a possible first-come-first-served DER queuing model (Recommendations 9 and 11). Industry participants also highlighted auto-enrollment as a significant driver of program participation relative to opt-in structures, proposed public schools as an anchor use case for solar-plus-storage aggregation (Recommendation 8), and cautioned against evaluating DER aggregation through case-by-case utility proceedings rather than integrating it directly into utility planning (Recommendation 7).

The City of Charlottesville submitted written comments (a non-member stakeholder response) raising three points not otherwise captured in a specific recommendation: a request for direct state assistance and model “blueprints” for localities implementing DERs such as microgrids; a concern that interconnection infrastructure costs are unpredictably concentrated on whichever entity applies first on a given circuit (Recommendation 9); and a gap around emergency-operations and resilience-hub backup power that does not currently have a clear home among the report's recommendations — a gap also raised independently by Dawn Oleksy at Meeting 3.

Peer-State Learning

The Task Force received a briefing from the Massachusetts Department of Energy Resources on that state's experience, which informed the report's approach to compensation design and interconnection reform. Key takeaways included that interconnection and hosting-capacity constraints — not incentive levels — became Massachusetts's binding barrier over time, prompting a shift toward proactive grid planning; that storage economics depend on stacking multiple revenue streams, with long-term contracted revenue proving far more financeable than market-based revenue alone (Recommendation 4); and that residential program simplicity matters — Massachusetts ultimately moved to a flat, uncapped per-kWh incentive after its more complex, declining-block structure proved too burdensome for households to navigate.

Task Force Member Written Input (Homework)

The Task Force distributed two rounds of written homework assignments to all 16 members. Eight of 16 members responded to the first round, and six of 16 responded to the second.

- **Top challenges identified:** utility data access (Align Energy Advisors, Energy Commission of Virginia, Voltus); undervaluation of DER benefits in current cost-benefit frameworks (Align Energy Advisors, PEC); the absence of a statewide DER roadmap (Energy Commission of Virginia); local education and capacity gaps; and a structural conflict between net energy metering and capacity payments (Voltus).
- **Top opportunities identified:** shifting utility incentives from cost-of-service regulation toward return-on-equity mechanisms tied to grid optimization (VA-DSA); using pending grid-utilization legislation to value DER-driven infrastructure deferral (Recommendation 7); data-center-funded DER tariffs (Recommendation 2); and reducing Dillon's Rule and Municipal Lease Act constraints on local government DER deployment (City of Richmond).
- **Prioritization:** across both rounds, members consistently prioritized distribution capacity and peak-shaving applications, non-wires alternatives, and battery storage and automated load control, while ranking PJM energy/ancillary services and vehicle-to-grid (V2G) participation lowest for near-term focus. On business models, both utility-administered programs and third-

party aggregation drew support, with several members recommending a hybrid approach rather than choosing one exclusively.

- **Second-round themes:** responses to the second round varied widely on specific statewide deployment-target proposals, but showed near-universal agreement that interconnection reform — including performance-based standards and New York's Shared Interconnection Review (SIR) model — is the top near-term priority (Recommendation 9); a genuine split on whether upfront-cost subsidies for residential adoption are a worthwhile use of limited funding; and broad support for a permanent coordinating body (Recommendation 1). VA-DSA submitted a separate addendum arguing that deployment and interconnection progress should be sequenced ahead of VPP-market-building.

Source: Task Force Homework 1 and Homework 2 master response trackers.

One-on-One Member and Stakeholder Interviews

To go deeper than the group Task Force sessions and written homework allowed, the team conducted individual interviews with a subset of members, building in several cases directly on themes raised in each member's written homework responses.

Key takeaways from these discussions included:

- **Local Public-Sector Leasing and Procurement Barriers:** Statutory limitations—specifically the five-year cap on public leases under the Municipal Lease Act—restrict standard 20–25 year solar and battery storage PPAs, while limited municipal contracting vehicles and the absence of aggregated net metering across public accounts constrain local government project adoption.
- **Administrative Misinformation and Technical Assistance:** Internal legal concerns over PPA risk, resolved fire-code objections, and rigid cybersecurity compliance rules for smart grid devices act as primary adoption hurdles, pointing to a need for hands-on technical assistance rather than generic guidance documents for smaller and rural jurisdictions.
- **Interconnection Cost Conflation:** Network upgrade expenses and grid impacts associated with utility-scale solar are frequently conflated with distribution-level DERs, obscuring the distinct cost-benefit realities of local clean energy deployment.
- **Statewide Deployment Mandates and Governance:** Voluntary education and streamlined enrollment programs have historically lagged without binding targets; achieving scale requires numeric, statewide DER and storage deployment goals supported by a permanent, jointly resourced SCC and Virginia Energy coordinating entity.
- **Valuation Frameworks and Program Funding:** The absence of state-directed Social Cost of Carbon metrics leaves regulatory evaluations dependent on utility-submitted figures, while potential revenue mechanisms to capitalize DER programs include targeted data-center rate-class tariffs and reallocated carbon allowance proceeds.
- **Wholesale Aggregation Friction and Data Timelines:** Existing wholesale market participation models carry significant friction under emerging PJM Order 2222 frameworks, compounded by operational timing misalignments between utility peak-load-contribution (PLC) data releases and regional wholesale tariff deadlines.

- **Distribution-Focused VPPs and Large Commercial Pilots:** Virtual power plant deployment is shifting from purely regional capacity offsets toward distribution-level grid optimization, with large commercial flexibility pilots—such as data center integrations—serving as the most viable near-term test cases.
- **Edge-Connection Hardware and Flexible Interconnection:** Modernizing service-connection rules to formally account for behind-the-meter technologies, including smart panels and automated load management, can avoid costly, slow utility service and transformer upgrades.

Source: Individual interview and stakeholder session notes, August 2026.

Written Feedback on the Draft Report

Following circulation of the draft interim report, the Task Force received written comments, tracked-change edits, and formal position statements from several members—including Dominion Energy, Tony Smith (VA-DSA), Angela Navarro (Align Energy Advisors), Richard Caperton (SPAN), Emily Orvis (Voltus), and Ashish Kapoor (PEC), which were consolidated into a single feedback tracker organized by recommendation number to support resolution ahead of the final report.

- **Dominion Energy:** submitted a formal written position emphasizing that the Commonwealth should use existing frameworks rather than adding new mandates, noting the deployment targets and deadlines already in motion under current law. Also raised a technical concern about potential double payment between net metering and PJM compensation mechanisms, and cautioned against directly importing other states' interconnection standards given the distinct characteristics of Dominion's 34.5kV distribution system (Recommendation 9).
- **Tony Smith (VA-DSA):** feedback most heavily emphasized interconnection reform (Recommendation 9) and sequencing near-term deployment relief ahead of longer-term VPP market design (Recommendation 8).
- **Angela Navarro (Align Energy Advisors):** concentrated on compensation design (Recommendation 4) and PJM market integration (Recommendation 5).
- **Richard Caperton (SPAN):** proposed adding state funding support for service-upgrade-avoidance technology (such as UL-listed power control systems) to Recommendation 10.
- **Ashish Kapoor (PEC):** reinforced meeting discussions about the need for a more rigorous DER cost-benefit framework (Recommendation 6) and raised a potential Regional Greenhouse Gas Initiative (RGGI) proceeds redirection as one possible funding mechanism worth the Task Force's consideration.

Additional input from external stakeholders included recommendations from Advanced Energy United (AEU) and other input.

Source: Consolidated Task Force feedback tracker, September 2026.

Task Force Meeting 3 Discussion

At Meeting 3 (September 15, 2026), the full Task Force discussed the draft interim report. Two requests from members shaped how this report presents its findings and recommendations going forward: Bill Murray (Dominion Energy) requested that each recommendation and action be tagged with the type of

policy lever it requires — legislative (General Assembly), regulatory (SCC), or executive — so that readers can quickly identify who needs to act; and Emily Orvis (Voltus) requested that the report clearly distinguish recommendations already underway as a result of recent legislation from those that are genuinely new.

Delegate Dan Helmer stated his preference against establishing any new permanent task force or working group, favoring instead working within the Chief Energy Officer's existing office, with accountability maintained through periodic reporting to the relevant House and Senate committees (Recommendation 1). Separately, Caperton, Orvis, Lerch, Murray, and other members debated whether and how to set a quantified statewide DER/VPP deployment target; the Task Force's resolution was to defer a final decision until Virginia Energy Plan modeling results are public, and to prepare two to three candidate target framings (e.g., megawatts, percent of peak load made flexible, or customers enrolled) for discussion at Meeting 4, explicitly addressing electric cooperative and municipal utility scope and incorporating equity indicators alongside deployment metrics.

Source: Task Force Meeting 3 Key Takeaways Briefing (per attendee notes), September 15, 2026.

How Stakeholder Input Shaped the Report's Findings

Across all channels of engagement, three themes recurred consistently enough to directly shape the report's structure and priorities:

- **Interconnection reform is the most broadly supported near-term priority.** Public input, industry stakeholders, Task Force homework responses, one-on-one interviews, and written feedback on the draft report all independently identified interconnection modernization as a top priority, without meaningful opposition. This consistency directly informs the structural (not incremental) reform proposed in Recommendation 9.
- **No stakeholder opposed the report's overall direction.** While individual members and stakeholders raised substantive concerns and open questions — particularly around compensation design, statewide target-setting, and the scope of any permanent coordinating body — none opposed the Task Force's overall approach or its emphasis on DER adoption and market participation as mutually reinforcing goals.
- **Recommendation 8 (schools and public facility DER adoption) drew the broadest independent reinforcement.** Industry stakeholders, Joe Lerch, and written comments from VA-DSA each separately identified public-facility DER adoption — and the specific procurement, interconnection, and financing barriers particular to schools and local governments — as warranting stronger emphasis than in earlier drafts.

A smaller number of topics remain open for discussion at Meeting 4, most notably: whether and how to adopt a quantified statewide DER/VPP deployment target and, if so, in what units; the appropriate scope and authority of a permanent coordinating body under Recommendation 1, given Delegate Helmer's preference for working within existing structures; and how to resolve Dominion's technical concerns about net-metering/PJM double payment and the applicability of other states' interconnection models to Virginia's distribution system. These items are noted here rather than resolved, consistent with the Task Force's plan to finalize its position on each at Meeting 4.

C. Relevant Enabling Virginia Legislation

Over the past eight years, the Virginia General Assembly has passed a series of relevant legislation to support greater adoption of renewable energy resources and dispatchable resources to mitigate growing strain on Virginia's grid infrastructure. This legislation, listed below, provides a foundation for the DER Task Force's recommendations.

- **Grid Transformation and Security Act (2018)** — established Virginia's first battery storage mandate: State Corporation Commission pilot programs for up to 30 MW (Dominion Energy) and 10 MW (Appalachian Power), an initial pilot-scale target that preceded the VCEA's 2020 target.¹⁰⁸
- **Virginia Clean Economy Act (2020)** — foundational mandate: 16,100 MW of solar/onshore wind and up to 5,200 MW of offshore wind by 2035; 100% carbon-free electricity by 2045 (Dominion) and 2050 (Appalachian Power); original combined storage target of 3,100 MW (2,700 MW Dominion / 400 MW Appalachian Power) by 2035.¹⁰⁹
- **HB 285 / SB 223 (2026, Chapters 1042/997)** — establishes the Distributed Energy Resources Task Force itself, with a July 1, 2027 sunset.¹¹⁰
- **SB 254 / HB 807 (2026)** — expands Dominion's shared solar program by 525 MW (450 MW capped at no more than 51% low-income subscribers, 75 MW reserved for majority-low-income projects), effective by the earlier of 90% subscription/substantial construction or July 1, 2026, with a further 268 MW “part three” phase contemplated; mandates an SCC cost-benefit review, regulatory updates by December 31, 2026, and utility tariff filings by March 1, 2027.¹¹¹
- **SB 255 / HB 809 (2026)** — expands Appalachian Power's shared solar program by 50 MW (July 1, 2026) and a further 50 MW (January 1, 2028), requires consolidated “net crediting” billing, and directs a further SCC expansion proceeding by May 1, 2029.¹¹²
- **HB 895 / SB 448 (2026)** — raises the combined Dominion/Appalachian Power storage target from 3,100 MW (VCEA, 2020) to approximately 21,300 MW (Dominion: 16,000 MW short-duration + 4,000 MW long-duration, by 2045; Appalachian Power: 780 MW short-duration, by 2040, + 520 MW long-duration, by 2045), with 20% of the long-duration target sited in the coalfield region; contingent on an SCC viability determination due by March 1, 2031, which may adjust the targets downward. Creates separate short-duration and long-duration procurement categories and directs the Department of Energy to develop model local ordinances.¹¹³
- **HB 284 (2026)** — requires Dominion and Appalachian Power to petition the SCC by January 15, 2027 for approval of voluntary demand-flexibility programs targeting high-energy-demand customers (25

¹⁰⁸2018 Acts of Assembly, Chapter 296 (SB 966), <https://law.lis.virginia.gov/uncodifiedacts/2018/session1/chapter296/>; storage pilot capacity figures (30 MW Dominion / 10 MW Appalachian Power) per <https://virginiamercury.com/2019/11/15/battery-storage-could-be-a-key-to-cutting-emissions-whats-virginia-doing-about-it/>. ^Δ Non-Virginia-government source used only to confirm the MW split; the chapter itself is the primary source for the mandate.

¹⁰⁹2020 Acts of Assembly, Chapter 1193 (HB 1526) / Chapter 1194 (SB 851), codified in relevant part at Code of Virginia § 56-585.5, <https://law.lis.virginia.gov/vacode/56-585.5/>.

¹¹⁰2026 Acts of Assembly, Chapter 1042 (HB 285) / Chapter 997 (SB 223), <https://lis.virginia.gov/bill-details/2026/HB285>.

¹¹¹Virginia H.B. 807 / S.B. 254 (2026), codified in relevant part at Code of Virginia § 56-594.3, <https://lis.virginia.gov/bill-details/2026/HB807>; program capacity split (450 MW / 75 MW) per Dominion Energy, “Shared Solar Program,” <https://www.dominionenergy.com/virginia/renewable-energy-programs/shared-solar-program>. Signed by Governor Spanberger April 14, 2026.

¹¹²Virginia H.B. 809 / S.B. 255 (2026), <https://lis.virginia.gov/bill-details/2026/HB809>. Signed by Governor Spanberger April 14, 2026.

¹¹³Virginia H.B. 895 / S.B. 448 (2026), amending Code of Virginia §§ 56-580 and 56-585.5 and adding Title 45.2, Chapter 22 (§ 45.2-2200), <https://lis.virginia.gov/bill-details/2026/HB895>; coalfield-siting detail per Energy Commission of Virginia, 2026 Energy Legislation Summary, https://dls.virginia.gov/commissions/eur/files/Energy_Legislation_Virginia_2026_CEUR_Summary.pdf (Division of Legislative Services, an agency of the Virginia General Assembly). Effective July 1, 2026.

MW+ demand, 75%+ load factor); electric cooperatives serving comparable customers must establish similar programs by January 1, 2029.¹¹⁴

- **HB 434 / SB 621 (2026, Chapters 611/612)** — requires Dominion and Appalachian Power to petition the SCC, by October 15, 2026, for approval of electric grid utilization metrics comparing current grid performance to optimal utilization of existing assets, including analysis of non-wires alternatives.¹¹⁵
- **HB 628 / SB 175 (2026) — “Distributed Generation Expansion Act”** — Expands the VCEA's behind-the-meter distributed-generation RPS carve-out from 1% to 4.5% of retail sales for compliance years 2026–2030, rising to 5% for 2031–2045; delays Dominion's requirement that 75% of distributed-generation RECs be Virginia-sited from 2025 to 2027; and removes the prior capacity restriction on the residential third-party power purchase agreement pilot.¹¹⁶
- **HB 1255 (2026)** — raises the net-metering standby-charge threshold from 15 kW to 20 kW.¹¹⁷
- **SB 823 / HB 590 (2026) — Residential solar consumer-protection legislation** — requires a standardized consumer disclosure form, laying out system specifications, costs, and financing terms, to be signed prior to contract execution for residential solar installations.¹¹⁸
- **SB 487 / HB 562 (2026)** — Expands Virginia's VPP pilot program authority (originally established for Dominion under SB 1100/HB 2346, 2025) to electric cooperatives. Signed March 31, 2026.¹¹⁹
- **SB 382 / HB 395 (2026) — “Smart Rooftop Permitting”** — Establishes a state-managed automated permitting platform for residential solar and storage systems meeting standard safety and design criteria.¹²⁰

D. EPDI VPP Policy Framework

Placeholder

E. Example DER Interconnection Implementation Changes

The items below are supplemental analysis and resources provided by EPDI, a consulting firm engaged in supporting the Task Force, related to Recommendation 9 about DER Interconnection.

Change 1: Establish a Unified Interconnection Framework for All State-Jurisdictional DERs

The following change to Chapter 314 would allow for consolidation of interconnection rules for all state-jurisdictional DERs within this chapter:

20VAC5-314-10. Applicability and scope; waiver.

¹¹⁴Virginia H.B. 284 (2026), <https://lis.virginia.gov/bill-details/2026/HB284>.

¹¹⁵2026 Acts of Assembly, Chapter 611 (HB 434) / Chapter 612 (SB 621), <https://lis.virginia.gov/bill-details/2026/HB434/text/CHAP0611>; bill text (October 15, 2026 petition deadline) per <https://legiscan.com/VA/text/SB621/id/3361187>.

¹¹⁶Virginia H.B. 628 / S.B. 175 (2026), <https://lis.virginia.gov/bill-details/2026/HB628>; provisions as described by the Solar Energy Industries Association, <https://seia.org/news/statement-spanberger-delivers-on-energy-affordability/>, and Advanced Energy United, <https://advancedenergyunited.org/blog/virginias-2026-legislative-session-delivered-major-clean-energy-wins/>.

¹¹⁷Virginia H.B. 1255 (2026), amending Code of Virginia § 56-594, <https://lis.virginia.gov/bill-details/2026/HB1255>.

¹¹⁸Virginia S.B. 823 / H.B. 590 (2026), <https://lis.virginia.gov/bill-details/2026/SB823>; described in Solar United Neighbors, <https://solarunitedneighbors.org/news/new-solar-laws-to-celebrate-in-virginia/>.

¹¹⁹Virginia S.B. 487 / H.B. 562 (2026), <https://lis.virginia.gov/bill-details/2026/SB487>; described in National Caucus of Environmental Legislators, <https://www.ncelenviro.org/articles/virginia-leads-the-way-on-energy-affordability-in-2026/>.

¹²⁰Virginia S.B. 382 / H.B. 395 (2026), <https://lis.virginia.gov/bill-details/2026/SB382>

A. This chapter is promulgated pursuant to § 56-578 of the Virginia Electric Utility Regulation Act (§ 56-576 et seq. of the Code of Virginia). This chapter establishes standardized interconnection and operating requirements for the safe operation of electric generating facilities in Virginia. This chapter applies to utilities providing interconnections to retail electric customers, independently owned generators, and any other parties operating, or intending to operate, a distributed generating facility in parallel with utility systems. This chapter also applies to equipment used for the storage of electricity for later injection to utility systems. This chapter does not apply to customer generators that fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC).

The following changes to Chapter 315 would eliminate interconnection provisions that are already addressed in Chapter 314 from this Chapter:

20VAC5-315-40. Conditions of operation.

A. A prospective customer may begin operation of the generating facility ~~on an interconnected basis~~ when the generating facility satisfies the interconnection requirements of 20VAC5-314.:

B. For an investor-owned electric distribution company, a prospective customer or small agricultural generator shall not be allowed to ~~participate in net energy meteringinterconnect a generator to the distribution system~~ if doing so will cause the total rated generating alternating current capacity of all interconnected net metered generators, as defined in 20VAC5-315-20, within that customer's electric distribution company's Virginia service territory to exceed 6.0%, in the aggregate, 5.0% that is available to all customers and 1.0% that is available only to low-income utility customers of that company's adjusted Virginia peak-load forecast for the previous year. In any case where a prospective customer has submitted a notification form required by 20VAC5-315-30 and that customer's interconnection would cause the total rated generating alternating current capacity of all interconnected net metered generators, as defined in 20VAC5-315-20, within that investor-owned electric distribution company's service territory to exceed of that company's Virginia peak-load forecast for the previous year the limitations described in this subsection, the electric distribution company shall, at the time it becomes aware of the fact, send written notification to the prospective customer and to the commission's Division of Public Utility Regulation that the interconnection is not allowed. In addition, upon request from any customer, the electric distribution company shall provide to the customer the amount of capacity still available for interconnection pursuant to § 56-594 D of the Code of Virginia.

C. For an electric cooperative, a prospective customer shall not be allowed to ~~participate in net energy meteringinterconnect a generator to the distribution system~~ if doing so will cause the total rated generating alternating current capacity of all interconnected net metered generators, as defined in 20VAC5-315-20, within the cooperative's Virginia service territory to exceed the following percentages of system peak: (i) for nonjurisdictional and nonprofit customers, 2.0% of the cooperative's system peak; (ii) for residential customers, 2.0% of the cooperative's system peak; or (iii) for other nonresidential customers, 1.0% of the cooperative's system peak. Such caps shall not decrease but may increase if the system peak in any year exceeds the previous year's system peak. For purposes of calculating the caps established in this subsection, all net energy metering shall be counted, whenever interconnected, and shall include net energy metering interconnected pursuant to § 56-594 of the Code of Virginia, agricultural net energy metering, and any net energy metering entered into with a third-party PPA provider registered pursuant to § 56-594.01 K of the Code of Virginia. Net energy metering

with nonjurisdictional customers entered into prior to July 1, 2019, may be counted toward the caps, in the discretion of the cooperative, as net energy metering if the nonjurisdictional customer takes service pursuant to a cooperative's net energy metering rider. Net energy metering with nonjurisdictional customers entered into on or after July 1, 2019, shall be counted toward the caps by default unless the cooperative has reason to exclude such net energy metering as subject to a separate contract or arrangement. Each electric cooperative governed by this section shall publish information regarding the calculation and status of its caps, or the electric cooperative's systemwide cap established via § 56-585.4 or 56-594.01 G of the Code of Virginia if applicable, on the electric cooperative's website. In any case where a prospective customer has submitted a notification form required by 20VAC5-315-30 and that customer's interconnection would cause the total rated generating alternating current nameplate capacity of all interconnected net metered generators to exceed the percentages stated in this subsection, the electric cooperative shall, at the time it becomes aware of the fact, send written notification to the prospective customer and to the commission's Division of Public Utility Regulation that the interconnection is not allowed and shall update its website. In addition, upon request from any customer, the electric distribution company shall provide to the customer the amount of capacity still available for interconnection pursuant to § 56-594.01 F of the Code of Virginia.

D. The capacity of any generating facility installed between July 1, 2015, and July 1, 2020, shall not exceed the expected annual energy consumption based on the previous 12 months of billing history or an annualized calculation of billing history if 12 months of billing history is not available. In the certificated service territory of a Phase I Utility, the capacity of any generating facility installed pursuant to this section after July 1, 2020, shall not exceed 100% of the expected annual energy consumption based on the previous 12 months of billing history or an annualized calculation of billing history if 12 months of billing history is not available. In the certificated service territory of a Phase II Utility, the capacity of any generating facility installed pursuant to this section after July 1, 2020, shall not exceed 150% of the expected annual energy consumption based on the previous 12 months of billing history or an annualized calculation of billing history if 12 months of billing history is not available.

20VAC5-315-75. Participation of small agricultural generators.

A small agricultural generator electing to participate in net energy metering pursuant to this section shall enter into a power purchase agreement with its supplier to sell all of the electricity generated from its small agricultural generating facility. The customer's supplier shall be obligated by the power purchase agreement to purchase the electricity generated at a price equal to a rate agreed upon by the parties that is not less than the utility's commission-approved avoided cost tariff for energy and capacity.

Small agricultural generators with renewable energy certificates or other environmental attributes generated by the small agricultural generating facility shall have the rights described in 20VAC5-315-50.

Small agricultural generators shall abide by the small generator interconnection process described in 20VAC5-314. Such customer shall be responsible for all costs associated with any interconnection or engineering studies that may be required prior to interconnection.

Change 2: Modernize Virginia's interconnection procedures through alignment with the IREC Model Interconnection Procedures

The New Mexico Public Regulation Commission provides an illustrative example of a commission-initiated rulemaking to align the state's administrative rules with the IREC *Model Interconnection Procedures*. In [Docket No. 21-00266-UT](#), the PRC opted to align its interconnection rules with the IREC model following consideration of the use of the FERC *pro forma Small Generator Interconnection Procedures* as a model. Its Order in this proceeding is instructive of the reasoning for alignment with the IREC *Model Interconnection Procedures* and included the incorporation of an IREC reference for energy storage interconnection that was integrated into the 2023 edition of the *Model Interconnection Procedures*.

Should it be determined that legislation is needed to provide guidance to the SCC regarding alignment of Chapter 314 with national models for interconnection procedures, New Hampshire and Delaware provide recent examples.

New Hampshire [Senate Bill 391](#): An Act Relative to Electric Grid Interconnection for Certain Customer Generators: In 2024, New Hampshire enacted legislation to update its interconnections rules, which had not been amended since 2001. As a result of Senate Bill 391, the New Hampshire Department of Energy completed a rulemaking to unify its interconnection rules in a single, new chapter and to align those rules with the IREC *Model Interconnection Procedures 2023*. New Hampshire's new interconnection rules were adopted in July 2026.

The bill language reads as follows:

1 Department of Energy; Draft Rules; Distributed Energy Resources. In order to set cost effective, timely, and predictable processes for customer generators wishing to interconnect to the state's electric grid, within 60 days of the effective date of this section, the department of energy shall open a proceeding to examine and assess draft rules to be adopted for the purposes of setting uniform procedures for distributed energy resources that are proposed for interconnection to the electrical infrastructure of New Hampshire's investor owned utilities and are not subject to Federal Energy Regulatory Commission jurisdiction. The draft rules shall include detailed applicability and eligibility requirements and provisions related to engineering standards, review processes, time lines, cost responsibilities, information sharing and transparency, and dispute resolution that are aligned with national best practices, including the Interstate Renewable Energy Council's 2023 model interconnection procedures. The draft rules shall utilize the comments the department of energy received as part of its investigatory proceeding in IP 2022-01. The PUC rule 900 shall remain in effect until any rules adopted pursuant to this section become effective. Any new employee positions required to implement this chapter shall be approved by the fiscal committee of the general court.

2 Effective Date. This act shall take effect upon its passage.

Delaware [House Bill 269](#): An Act to Amend Title 26 of the Delaware Code Relating to Net-Metering and Interconnection Rules: In 2026, Delaware enacted legislation that updated state statute to require its electric utilities to adopt the IREC *Model Interconnection Procedures* within 12 months of publication. Delaware had adopted interconnection standards in 2011 based largely on the 2005 edition of the IREC

Model Interconnection Procedures but had not updated them since. The Delaware Public Service Commission is currently in the process of amending its interconnection standards per the requirements of HB 269.

The bill language reads as follows:

Section 1. Amend § 1014, Title 26 of the Delaware Code by making deletions as shown by strike through and insertions as shown by underline as follows:

§ 1014. Public purpose programs and consumer education [For application of this section, see 85 Del. Laws, c. 83, § 2].

(e) The rules and regulations promulgated for net energy metering by the Commission, municipal electric companies, and electric cooperatives during any period of exemption under § 223 of this title must consider the reliability, safety, and capacity of the electric distribution system and:

(5) Require that all generating systems and grid-integrated electric vehicles used by eligible customers meet all applicable safety and performance standards established by the National Electrical Code, and those of the Institute of Electrical and Electronic Engineers, UL, or the Society of Automotive Engineers, to ensure that net metering customers meet applicable safety and performance standards and comply with the electric supplier's interconnection tariffs and operating guidelines. ~~An electric supplier's interconnection rules must be developed by using as a guide~~ supplier must adopt the Interstate Renewable Energy Council's Model Interconnection Rules and best practices identified by the U.S. Department of Energy. Municipal electric companies shall establish interconnection rules no later than July 24, 2008. Procedures (Procedures) within 12 months of the Procedures' latest publishing date. Any deviation from the Procedures must be affirmatively approved by the utility's regulatory body in a formal proceeding. The utility regulating authority may establish, monitor, and enforce mandatory interconnection application processing timelines and project milestones within its interconnection rules, including commensurate consequences for failure by an electric supplier to meet such deadlines, unless delays are demonstrably attributable to the applicant. An electric supplier may not require eligible net-metering customers who meet all applicable safety and performance standards to install excessive controls, perform or pay for unnecessary tests, or purchase excessive liability insurance. Commission-regulated electric utilities may recover prudently incurred implementation costs including administrative fees, back-office technology upgrades, and customer system investments necessary to decrease overall project execution timelines and ensure projects are brought online within the prescribed timelines.

Change 3: Implement flexible interconnection pathways for energy storage resources

Illinois provides an illustrative example of regulator-directed efforts to implement flexible interconnection programs. ComEd and Ameren, in conjunction with multiple parties, have developed flexible interconnection plans for various styles of flexible interconnection, including:

- Static, which limits export below the nameplate capacity of the DER;
- Volt-watt, which uses smart inverter controls that are responsive to voltage conditions;
- Phased, which allows for the DER to limit its export until needed upgrades are completed;
- Scheduled, which requires the DER to limit its export based on defined time windows; and
- Dynamic, which often involves actively managed control of the DER, either through DERMS or other utility control.

ComEd has published its [flexible interconnection plan](#) and began implementation in late 2025. Ameren has published [Phase 1](#) and [Phase 2](#) of its flexible interconnection plan.

ComEd’s plan was developed through a [series of workshops](#) that defined the technical and programmatic requirements of the program.

Change 4: Establish clear standards and timelines for the approval and use of meter socket adapters to streamline interconnection of energy storage systems

There are several examples of utilities and states that have formally addressed the use of meter socket adapters (MSAs). These include:

- PG&E [Rule 31](#), a utility tariff for customer-owned MSAs;
- Colorado [House Bill 26-1007](#), which was enacted in 2026 and amended state statute to require qualifying utilities to approve MSAs;
- Connecticut PURA [Order No. 261](#) in Docket No. 24-08-02, which directed the state’s utilities to advance the review process for MSAs;
- Delaware PSC [Order No. 10908](#) that amended the state’s net metering regulations to require the approval of MSAs that meet specific criteria;
- [Chapter 40](#) of the District of Columbia Municipal Regulations that specifies the requirements for MSAs;
- Maryland has incorporated provisions related to MSAs in its [interconnection rules](#);
- Massachusetts passed [legislation](#) in 2024 directing its utilities to approve MSAs;
- New Jersey passed legislation in 2023 requiring its utilities to approve MSAs that meet certain criteria (see [New Jersey Statutes 48:3-111.1](#));
- In a September 2026 [Order](#), the New York PSC directed its utilities to launch a pilot for approving MSAs that requires utilities to begin accepting interconnection applications that include MSAs by June 2027.

F. Summary of DER Modeling Outputs

Long-Term Forecast for Virginia's Distributed Energy Resource Adoption and Load Impact

This appendix summarizes the methodology, key findings, and outputs of the DER and VPP adoption modeling effort conducted by the Deloitte modeling team in parallel with the Task Force's deliberations. This summary is not intended to substitute for the analysis but to orient Task Force readers to its scope and conclusions.

1. Purpose and Scope

The modeling supports Virginia Energy's State Energy Plan and the Commonwealth's FERC Order 2222 compliance by (1) providing enhanced DER adoption assumptions for Virginia Energy's PLEXOS-based SEP modeling and (2) giving the Task Force a standalone scenario framework for evaluating DER/VPP policy options, modeling adoption under six scenarios to 2045 and identifying gaps relative to Virginia's DER goals.

- **DER types / segments:** customer-owned rooftop solar PV, battery storage (standalone and solar-paired), and managed EV charging; residential and commercial customers modeled separately.
- **Geography:** Dominion Energy, Appalachian Power Company (APCo), and an aggregated Co-ops/Municipalities region.
- **Horizon and financing:** annual results, 2025–2045, from hourly dispatch, in constant 2024 dollars; four financing options tested — 100% cash, 0%-down loans at 5% and 3.25% real interest, and third-party lease.

2. Baseline and Scenario Design

The model is calibrated to Virginia's observed 2024 DER fleet of approximately 1,140 MW (more than 20x its 2016 level) built from utility filings. Customer-owned solar PV leads at 874 MW-DC (about three-quarters of the total, up from 40 MW-DC in 2016); battery storage (92 MW-DC) and shared solar (116 MW-DC) are smaller but growing quickly; demand response remains smallest at about 60 MW. Growth accelerated sharply after 2021, roughly tripling from ~380 MW to ~1,140 MW by 2024, with the largest single-year jump (~370 MW) in 2023.

The forward model varies two independent drivers: DER adoption (how much equipment gets installed) and VPP participation (how much of that capacity is enrolled and dispatchable). Crossing three adoption levels (Low/BAU, Medium, High) with two participation levels (Low, High) produces six scenarios, run alongside a standalone BAU case:

Scenario	DER Adoption	VPP Participation	Design Intent
1A / 1B	Low	Low / High	Conservative adoption; tests grid value extractable from a limited fleet (1B).
2A / 2B	Medium	Low / High	Moderate acceleration via cost declines and new incentives; 2B adds high enrollment.

Scenario	DER Adoption	VPP Participation	Design Intent
3A / 3B	High	Low / High	Maximum plausible adoption; 3B is the ceiling case for dispatchable capacity.

Higher adoption levels pair faster technology cost declines (per NREL's Annual Technology Baseline) with richer incentives and higher retail rate escalation, shortening customer payback. VPP participation is set independently: enrollment ramps from 2026 (the Dominion VPP tariff) to a ceiling by 2035 as pilots conclude and PJM-wide DER aggregation matures.

3. Modeling Approach

The modeling framework applies three layers of analysis, each addressing a distinct question:

- **Layer 1 — Technology adoption:** forecasts how many customers install solar, storage, or enroll in managed charging, based on customer economics. For each purchase year, the model builds a full project cash flow, derives the resulting payback period, and maps that payback to a maximum market share using an established willingness-to-adopt curve; a Bass diffusion curve then sets the pace at which that ceiling is approached. Solar and storage are modeled in the ElectrifiedGrid platform; managed EV charging uses a separate Excel-based model.
- **Layer 2 — VPP participation:** applied on top of the adoption forecast rather than within it. This layer rescales how much of the installed capacity is enrolled and dispatchable in a given hour, without altering how much capacity was actually installed — reflecting that a battery optimizing a household's own bill contributes nothing at system peak unless it is enrolled in a program that can call on it.
- **Layer 3 — Policy alignment:** combines targeted supplemental model runs with post-processing of the finalized outputs to test alignment against existing and proposed policy levers, including the 10 GW DER capacity concept and the HB 628 SREC carve-out.

Key data inputs include U.S. Census housing and establishment counts narrowed by Google Solar API rooftop suitability, NREL PVWatts v8 hourly generation profiles, Virginia DMV EV registration data, PJM EV stock projections, and Dominion's 2025 Integrated Resource Plan residential bill projections (used to derive real retail rate escalation). As with the Technical Baseline document prepared for the modeling team, all inputs are drawn from utility filings, government data, or documented industry sources; where an assumption required judgment — for example, the \$250/kW-year VPP incentive tested in Section 5.4 below — the working paper documents the basis and range.

4. Key Findings

4.1 Overall DER Capacity and the 10 GW Reference Point

Tested against a 10 GW reference level (2045, cash financing, no VPP participation), the Low/BAU scenario reaches 9.4 GW — 0.6 GW short — while Medium (13.9 GW) and High (19.3 GW) both clear it. Solar PV drives almost all of the difference (5.8 → 9.8 → 14.8 GW); battery storage moves only from 3.4 to 4.3 GW, and managed EV charging stays roughly flat (~0.2–0.3 GW). Because most achievable

capacity is non-dispatchable solar, only a minority of the 2045 fleet (~3.7 GW in the Low scenario) is dispatchable. The working paper's framing: the economic case for 10 GW exists, but reaching it needs customer adoption support, and unlocking the dispatchable share needs additional storage incentives and VPP enrollment. Residential solar is the most incentive-responsive technology studied, projected at 80–87% of total solar capacity by 2045.

4.2 Solar and Storage Adoption by Sector

- **Residential solar:** grows in every scenario with meaningful separation between Low/Medium/High, indicating incentives have a binding effect. Most statewide adoption occurs in Dominion territory (larger eligible pool), though APCo customers see shorter paybacks from higher rates.
- **Residential storage (paired/standalone):** limited across all scenarios — paired storage is capped by the solar market and only grows meaningfully in the High scenario after 2035; standalone storage sees the lowest uptake of any technology studied, constrained by a shrinking eligible market and weak time-of-use economics.
- **Commercial solar:** grows in all scenarios but plateaus around 2035 as decision-makers reach a willingness-to-adopt ceiling; Medium vs. High incentives show limited incremental benefit, unlike the residential pattern.
- **Commercial storage:** shows markedly stronger uptake than residential, reflecting access to demand-charge reduction and other revenue streams.

4.3 Managed EV Charging

Passive, rate-driven charging shifts grow slowly through the late 2020s, reaching ~150 MW of statewide peak-hour shift by 2045 (~100 MW Dominion, 35 MW APCo, 10 MW co-ops). Under active, utility-controlled dispatch (full EV participation assumed), peak-hour load removal deepens from ~1.2 MW (2025) to ~50 MW (2046), concentrated in short windows at system peak.

4.4 Virtual Power Plants: Participation Matters More Than Adoption

For dispatchable capacity, enrollment matters far more than installation volume. Under cash financing, statewide 2045 VPP capacity ranges ~1.2–1.5 GW (low participation) to ~3.85–4.36 GW (high participation) — a 2.8–3.1x lift from participation alone — while moving from low to high DER adoption (holding participation constant) adds only 300–500 MW (13–24%). Managed EV charging shows the largest participation-driven lift (~272 → ~2,093 MW, ~7.7x) versus ~1.7–1.8x for batteries, reflecting much higher assumed EV enrollment ceilings (10–75%) than battery ceilings (35–70%). Batteries still make up ~80% of VPP capacity at low participation; higher adoption shifts the battery mix toward solar-paired systems.

Policy-relevant finding: VPP incentives for residential storage

A supplemental \$250/kW-year VPP incentive (within the \$225–275 range observed in utility pilots) produced residential battery adoption increases of 6%, 12%, and 33% in the Low, Medium, and High scenarios — nearly all incremental growth was residential, where storage adoption is otherwise weak. Takeaway: VPP incentives can meaningfully accelerate residential storage adoption, but amplify rather than replace broader supportive conditions (cost declines, financing, rate design).

4.5 Financing

Leasing and 0%-down loans produce higher modeled solar adoption than cash purchase, indicating upfront cost is a real adoption barrier — though third-party ownership means benefits are split with the financier rather than fully retained by the customer. For storage, 0%-down financing materially lifts commercial adoption regardless of interest rate (access matters more than rate), while residential financing has limited effect where underlying economics are already weak.

Financing is decisive for one policy test: HB 628 SREC carve-out compliance (5.0% of retail sales). Only the three lease-financed scenarios sustain compliance, crossing 5.0% in 2032 and holding through 2045 under every adoption pathway; cash never exceeds ~4%, and loan-financed scenarios exceed the target only temporarily (2034–2043) under High adoption. This assumes all statewide solar output counts toward the carve-out with no RECs resold elsewhere — an upper-bound assumption, so actual compliance is likely tighter.

5. Outcomes, Limitations, and Next Steps

- **Outputs:** an annual, bottom-up Virginia DER adoption forecast (solar PV, paired/standalone battery storage, managed EV charging) by utility service area; hourly load/generation profiles for PLEXOS analysis; and an assessment of results against policy levers (statewide DER target, HB 628 carve-out) and incentive designs (financing, residential VPP incentive).
- **Limitations:** adoption is modeled as purely economic (non-financial factors like reliability preference aren't captured); managed EV charging/VPP programs are early-stage nationally, limiting empirical calibration data; the analysis excludes other flexible-load resources (e.g., smart thermostats, data center shifting); and the financing analysis models customer demand only, not supply-side constraints (installer capacity, equipment availability, workforce) that could bind realized adoption, particularly under leasing.
- **Opportunities to extend analysis:** evaluate dispatchable VPPs' impact on peak load and generation investment needs within PLEXOS; analyze additional flexible-load resources' role in VPPs; and use ElectrifiedGrid to reassess adoption and system impacts as market conditions evolve.

6. Summary of Results

Across the six scenarios, Virginia's DER fleet grows substantially from its 2024 baseline of ~1,140 MW to between 9.4 GW (Low/BAU) and 19.3 GW (High) of installed capacity by 2045, clearing a 10 GW reference level under Medium and High adoption but falling just short (by 0.6 GW) under BAU conditions. Solar PV drives nearly all of this growth and nearly all of the spread between scenarios, while battery storage and managed EV charging capacity remain comparatively flat regardless of adoption pathway, meaning most of the achievable 2045 fleet is non-dispatchable. The more consequential lever is not adoption but VPP participation: enrollment alone drives up to a 3.1x difference in dispatchable 2045 capacity (ranging ~1.2–4.4 GW statewide), far outweighing the 13–24% difference attributable to DER adoption level alone. Financing structure and targeted incentives are the two most actionable policy levers identified: leasing and 0%-down financing materially increase solar and storage adoption by removing upfront cost barriers, and leasing is the only financing path that sustains HB 628 SREC carve-out compliance through 2045, while a modest, pilot-tested VPP incentive (\$250/kW-year) meaningfully

narrows the residential battery adoption gap relative to commercial customers. Taken together, the results indicate Virginia is on track to reach meaningful DER capacity under current economic and policy trends, but converting that capacity into a materially dispatchable, grid-supportive resource, rather than a predominantly non-dispatchable solar fleet, will require deliberate policy intervention targeted at VPP enrollment and storage incentives specifically, not at DER adoption incentives alone.