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Virginia Distributed Energy Resources White Paper

From Fragmented Policy to Integrated System Design: A Roadmap for an Affordable, Resilient and Fully Utilized Distributed Grid

Prepared by the Virginia Distributed Solar Alliance (VA-DSA)

As a resource for the Virginia DER Task Force (SB 223 / HB 285)

and the Virginia Department of Energy in support of the Governor's Energy Policy

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Guide To This Paper

This white paper is offered as a resource to the Virginia DER Task Force and the Virginia Department of Energy, not a substitute for either process. It compiles research, national precedent, and draft policy options across the five statutory responsibility areas assigned to the Task Force under HB 285, organized around Chief Energy Officer Allmond's principle, "Adopt, Don't Pilot," so each recommendation is paired with a proven operating model.

Table 1. HB 285 Crosswalk

HB 285 Statutory Responsibility	White Paper Section
Barriers to deployment	Section 1 (current-state assessment)
Incentives / financing	Section 2, Incentives
Interconnection	Section 3, Interconnection
Permitting / local government	Section 4, Permitting
Grid integration	Section 5, Grid Integration & Virtual Power Plants
Customer engagement / public awareness	Section 6, Public Awareness and Engagement
Maintain the Commonwealth's competitiveness	Section 7, Workforce Development
Recommendations / implementation	Sections 8–9, Systems Framing & Roadmap
Best practices	Appendices A–F (national models)

Executive Summary

Virginia has already begun the shift toward a fully utilized grid: HB 434 now requires Phase I and Phase II utilities to report on grid utilization and evaluate non-wires alternatives G-1. This paper is the logical next step, turning that reporting requirement into the coordinated incentive, interconnection, permitting, and grid-integration framework Virginia needs to act on the results, and become the national leader in affordable distributed energy. **Virginia's next energy transition is not about building more infrastructure — it's about using the existing grid far more efficiently.** Every recommendation that follows supports that thesis within a systems framework, and puts it into practice based on proven precedent.

A 10% Improvement in Grid Utilization Can, at the Same Time:

- Reduce customer rates by 3.4%
- Increase utility earnings by 23%
- Accelerate new-customer connections by several years
- Defer costly infrastructure investment

— The Brattle Group, "The Untapped Grid" (March 2026), Appendix G-2

FERC Order 2222 turns Virginia's distributed energy resources from a policy category into a revenue opportunity. HB 434 supplies the diagnostic tool; Order 2222 supplies the deadline and mechanism, opening PJM's wholesale markets to aggregated DERs so a homeowner's battery, a school's rooftop system, or a co-op's demand-response program can earn wholesale market revenue directly. It rewards flexibility over size and creates the predictable revenue stream that attracts private capital into DER deployment at scale. Capturing that opportunity depends on the same categories this paper addresses in turn: incentives, interconnection, permitting, and grid integration.

This paper identifies the barriers standing between Virginia and a fully utilized distributed grid and pairs each with a demonstrated operating model, following Chief Energy Officer Josephus Allmond's principle: **"Adopt, Don't Pilot."** Table ES-1 summarizes each pairing; Sections 2 through 7 develop each into a Virginia recommendation.

Table ES-1. Summary of Key Barriers and Proven Precedents

Barrier	Adopt
1. Incentives	
• **Utility Incentives**	Shift from COSR to enhanced ROE for grid utilization & DER metrics; alternatively, PBR for demand-flexibility incentives; MD Executive Order 01.01.2025.27 (non-wire alternatives evaluation)
• **Customer & Developer Incentives**	NY-Sun declining-block solar program; reinstatement of § 58.1-339.4. Qualified equity and subordinated debt investments tax credit for DER projects, that expired Jan 1, 2026.
• **Schools & Community Incentives**	Virginia Solar Schools & Communities (VSSC) program: modified version of PA Solar for Schools (S4S), incentive grants & PPAs via existing cooperative procurement
2. Interconnection	NY's Standardized Interconnection Requirements; DE's HB269 (IREC-based)
3. Commercial Rooftop Permitting	VEBC amendment proposed to DHCD (Oct. 2026) to streamline permitting and reduce costs
4. Grid Integration / VPPs	Amend HB 895 VPP for 10% behind-the-meter for non-utility VPP; MD PSC Order 92398 "Green Button" third-party aggregator directory; EV School Bus VPP
5. Workforce Development	Reinstate VA Department of Labor and Industry (DOLI) student solar apprenticeships (ages 16–18); fund community college training
6. Public Awareness and Engagement	Provide model solar PPA via VEPGA/VACO; solar PPA FAQ's for Local Governmental Attorneys (LGA); Statewide VA-DSA voter survey, modeled on a 2026 California survey

These recommendations hold regardless of how the SCC resolves the proposed Dominion–NextEra merger: the underlying barriers to DER deployment persist, and so does the requirement under FERC Order 2222 for DER participation in wholesale markets. Section 1.4 addresses this scenario planning in detail.

Section 9 organizes every recommendation by how it can move, immediate administrative action, the 2027 legislative session, regulatory proceeding, or long-term market transformation, aligned with the Task Force's own reporting timeline: an Interim Report (September 15, 2026), a Final Report (October 13, 2026), the Governor's Energy Plan, the 2027 General Assembly session, a Deployment Report (June 2027), and multi-year implementation through PJM's and FERC's 2222 timelines.

Executing these reforms at scale is itself an economic development opportunity: solar and storage installation is a fast-emerging, well-paying skilled trade, and the state that builds its training pipeline first captures the jobs, not just the panels (Section 7).

1. Context: The Virginia DER Moment

1.1 Why Now

The case for urgency is straightforward: rapid data center growth and electrification will roughly double Virginia's electricity demand within a decade, and an estimated 40–60% of existing grid capacity sits unused most of the year even as rates rise sharply under approved contracts. Shifting utility investment toward better grid utilization, rather than new capital build, could save consumers an estimated $110–180 billion nationally over the next decadeG-3, savings Virginia is positioned to capture given its data-center-driven load growth. Section 1 lays out the full scope of that pressure and why it hasn't yet been addressed.

Virginia is already the nation's largest net importer per capita of electricity, and the Joint Legislative Audit and Review Committee (JLARC) projects demand could nearly double within a decade, consistent with national forecasts of a 78% rise in electricity demand between 2023 and 2050[G-4]. Dominion's own 2025 Integrated Resource Plan forecasts a 2.6 GW capacity shortfall by 2031 absent new generation. What matters most to Virginians is what electricity costs them: cumulative rate increases are projected to reach 36% by mid-2027 under the recently approved VEPGA contract alone, a 25% increase in July 2026 followed by at least another 12% in July 2027, and residential bills could climb by more than $400 a year by 2040 if left unaddressed[G-6]. That pressure is not abstract: roughly 1 in 6 households nationally were already behind on their utility bills in 2026[G-5], a burden that a further $400 annual increase would only deepen. Maintaining reliability, affordability, and resilience for Virginia ratepayers will require a deliberate strategy and comprehensive reform, not incremental adjustment.

1.2 A Structural, Not Inevitable, Crisis

The pressure described in 1.1 is real, but it is not an argument for building more of the same. Under Virginia's Cost of Service Regulation (COSR) model, utilities earn returns almost exclusively through new capital investment, leaving little financial incentive to improve utilization of the grid. In 2023, the SCC approved $824.1 million in capital investment for Dominion's Phase III Grid Transformation Plan (2024–2026), funding main feeder hardening, advanced metering, and voltage optimization. By contrast, Dominion capped its first non-wires-alternative pilot, five battery storage systems over five years, at just $50 million in capital, roughly 6% of what it committed to traditional infrastructure in the same filing[G-8]. The Virginia Clean Economy Act (VCEA) catalyzed investment in generation; the next phase of Virginia energy policy must focus on how the grid operates, not only how much generation is built — effectively a "VCEA II" integrated approach. The grid is sized for peak demand but underutilized most of the year, load growth is outpacing infrastructure timelines, and costs are increasingly driven by transmission and distribution readiness rather than energy supply.

1.3 FERC Order 2222: The Catalyst for Reform

HB 434 gives Virginia the diagnostic tool to see where its grid is underused; FERC Order 2222 supplies the deadline and the market mechanism to act on what that diagnosis shows. Issued in 2020, Order 2222 requires every regional transmission organization, including PJM, to open its wholesale electricity markets to aggregated DERs, solar, storage, demand response, flexible load, turning compliance into a new revenue channel rather than a cost. But that market access depends simultaneously on functioning interconnection standards, coordinated permitting, a viable incentive structure, and a grid-integration framework capable of managing dispatch at scale: the same four categories Sections 2 through 5 address in turn. No single bill or utility pilot can satisfy a mandate spanning the entire distributed energy landscape; the DER Task Force provides the mechanism for the state-level alignment Order 2222 requires.

1.4 Regulatory and Legislative Backdrop

Virginia's institutional environment already shows real momentum: a cabinet-level Chief Energy Officer (Josephus Allmond), and a 2026 General Assembly session that produced fourteen DER-related bills, including HB 285 itself, projected to add 188 MW of reliable DER capacity[G-9]. Each bill is a genuine win, but collectively they remain a fraction of what the scale of Virginia's problem demands, and cannot on their own establish the market-participation framework FERC Order 2222 requires.

The proposed NextEra–Dominion merger could itself become a vehicle for evaluating utility incentives and transparency. This paper's recommendations are built to hold whether the merger is approved or not, and whether Virginia experiences moderate load growth, an accelerated optimization push, or severe grid stress, intentionally designed, in other words, as “no-regret strategies” that do not depend on any single merger outcome, Order 2222 implementation pace, or load-growth forecast proving correct.

1.5 Best-Practices Precedent: “Adopt, Don't Pilot”

Consistent with that principle, every recommendation in this paper is paired with a real operating precedent (detailed in the appendices), so the Task Force can assess not just whether an idea is sound, but whether it has already been demonstrated to work at scale.

1.6 Six Barriers, Six Proven Precedents

Table ES-1 in the Executive Summary summarizes the barriers standing between Virginia and a fully utilized distributed energy grid, each paired with the precedent this paper recommends Virginia adopt. Sections 2 through 7 develop each pairing into a specific legislative or regulatory recommendation, including the utility- and customer-incentive redesign, the public-entity solar program, the interconnection thresholds, the commercial permitting pathway, the VPP aggregator framework, workforce development, and public awareness and engagement.

2. Incentives

2.1 Regulatory and Legislative Reforms

This is an argument for realigning what utilities are rewarded for, not against them. Virginia's COSR framework ties utility profit to volumetric sales, so any reduction in electricity sold, including from DERs, directly cuts utility profit, the “throughput incentive” behind the capital bias ratepayers are now funding.

- **Regulatory Reform:** Performance-Based Regulation (PBR), under Commission docket review via HB 903 (SCC findings due 2027), decouples profit from capital spending and ties it to measurable performance metrics instead, letting utilities earn a return on the costs DERs help avoid. PBR takes multiple years of SCC proceedings to design, so Maryland's Executive Order 01.01.2025.27 offers a faster complement in the meantime: it requires utilities to prove they evaluated non-wires alternatives before defaulting to a major build (Appendix A-7).
- **Legislative Reform:** A faster, parallel path is to work within Virginia's existing ROE framework: extend an enhanced ROE adder to utilities for grid-optimization performance and for enabling customer- or third-party-owned DER deployment on their systems (full legal analysis in the Thompson McMullan ROE brief, Appendix A-1).

2.2 Taxpayer and Public-Entity Incentives

Ratemaking reform does not address the barriers facing schools, municipalities, and low-income households, which lack the upfront capital, taxable footprint, or property ownership Virginia's existing incentive structure assumes. Virginia already has the underlying mechanisms in place, a community solar carve-out for low-to-moderate-income households, a statewide property tax exemption for solar and storage, and cooperative procurement pathways for solar PPAs, but institutional inertia (bureaucratic barriers from legal counsel or procurement officers, with no accountability for missed savings) remains one of the highest barriers to public-entity adoption, even though public bodies have a basic stewardship duty to pursue no-cost savings opportunities.

The Virginia Solar for Schools & Communities (VSSC) program, summarized in the Governor-ready one-pager at Appendix F, is the practical vehicle this paper recommends for closing that gap. VSSC deploys solar and storage across public schools, community colleges, and municipal facilities using incentive grants and no-capital-cost PPAs financed through existing cooperative procurement, paired with the fast-track interconnection and permitting recommended in Sections 3 and 4. Expected outcomes include a 10–30% reduction in public-sector electricity costs with no upfront capital, a premium SREC market for school-based generation, and a workforce apprenticeship pipeline.

VSSC's timing is relevant to Google's $15 million Virginia Energy Impact Fund (announced June 2026), currently allocated to weatherization, efficiency, and workforce training, with full disbursement expected within six months, a narrow window to direct a portion toward VSSC before those dollars are committed elsewhere. That case is strengthened by the scheduled loss of federal commercial-scale solar tax credits in December 2027.

2.3 Net Metering Cap

Virginia's statutory 6% cap on aggregate net metering capacity is a hard ceiling on market growth precisely when growth is most needed. Raising or eliminating the cap should be paired with a Value of Distributed Energy Resources (VDER) compensation model rather than a straight extension of net metering, so that distributed assets are paid based on their actual locational and temporal value to the grid (Appendix A-4). Any expanded framework should also clarify how to avoid "dual benefit" by separately metering battery charge and discharge activity, distinct from metering solar production and exporting to the grid, so that only genuine solar generation receives the net-metering credit.

2.4 State DER Program Comparison

Three peer-state programs demonstrate that commercial-scale DER incentives are not a novel undertaking but an operating category with years of results across multiple states. Illinois's Shines program is the clearest precedent for the public-entity framework proposed in Section 2.2. Massachusetts's SMART program offers the strongest storage integration, directly relevant to the grid-integration barriers addressed in Section 5. New York's NY-Sun program is the working precedent for the pairing recommended in Section 2.3: a declining block incentive layered with Value Stack (VDER) compensation.

Table 2a. State DER Program Comparison

Dimension	NY-Sun (New York)	Illinois Shines	SMART (Mass)
Administering agency	NYSERDA; PSC oversight	Illinois Power Agency; ICC oversight	DOER; DPU tariff approval and oversight
Legislative basis	Launched 2014 under Reforming the Energy Vision	2016 Future Energy Jobs Act, expanded by 2021 Climate & Equitable Jobs Act	2016 Act to Advance Clean Energy; launched 2018
Incentive structure	MW Block, declining, paired with Value Stack / VDER for larger projects	Utilities purchase RECs from long-term contracts; prices decline as blocks fill	Fixed performance-based $/kWh tariff, on top of net metering credits
Contract term	Up to 25 years (Value Stack); upfront (MW Block)	~15 years	10 years residential / 20 years commercial
Program capacity goal	10 GW distributed solar by 2030	Sized to support 100% clean electricity by 2050	3,200 MW statewide solar target
Community solar	Major pillar, incl. renters, schools, nonprofits	Core category with subscriber protections	Dedicated low-income shared-solar carve-out
Storage emphasis	Value Stack compensates storage + locational value	Minimal; handled separately	Strong dedicated storage adders
Low-income / equity	Income-qualified carve-outs	Equity Eligible Contractor provisions	Low-income adder, roughly double the base rate
Interconnection standard	Single statewide SIR, up to 5 MW	Statewide, ICC-governed	Utility tariffs with DPU oversight
Cost recovery	System Benefit Charge + Clean Energy Fund	REC costs via ICC-approved rates	Ratepayer-funded, DPU-capped tariff

VPP Readiness / Deployment (as of mid-2026):

- New York: NYISO's DER Participation Model live; full FERC 2222 compliance required Dec. 31, 2026 (10 kW aggregation minimum excludes most residential batteries).
- Illinois: Clean and Reliable Grid Affordability Act (eff. June 1, 2026) requires utility VPP programs; ICC's own program (launched June 30, 2026) compensates batteries to 5 MW.
- Massachusetts: ConnectedSolutions (utility-run) pays ~$225/kW for summer battery discharge; Eversource/National Grid piloting vehicle-to-grid EV participation since July 2026.

Full program detail, including national precedent for VPP readiness, is provided in Appendices A-2, A-3, and A-5.

2.5 Large-Customer Models

Three models, both grounded in existing regional precedent, can transform hyperscale data centers from passive load into active grid assets.

- **Model A (Load Reduction)** offers hyperscalers a time-of-use discount for shifting demand off-peak using on-site batteries, adapting New York's VDER framework to design dynamic rates targeting Virginia's most congested nodes, such as Loudoun County.
- **Model B (Grid Asset Services)** would have utilities or PJM pay hyperscalers to discharge behind-the-meter batteries during peak periods, effectively creating a small-scale virtual power plant consistent with FERC Order 2222; because battery dispatch averages roughly $800/MWh versus more than $1,300/MWh for PJM emergency purchases during extreme congestion, this can reduce costs system-wide.
- **Model C (Bring Your Own Capacity)** would have hyperscalers finance residential solar and battery installations within their surrounding utility territory, aggregated into a VPP that satisfies the hyperscaler's own capacity and interconnection obligations.

2.6 Unified Benefit-Cost Analysis (NSPM)

None of the reforms above can be evaluated consistently without first answering a basic question: how does Virginia determine whether an energy investment is worth making? The National Standard Practice Manual (NSPM) provides a standardized benefit-cost framework, but Virginia currently limits its use to energy efficiency and demand-side management programs. Expanding NSPM to all DERs would shift regulatory debate from whether to invest in DERs to which options deliver the greatest value (Appendix A-6).

3. Interconnection

3.1 Current Barriers

Since December 2022, Dominion has imposed blanket Direct Transfer Trip (DTT) requirements on solar projects above 250 kW, typically capturing projects serving public schools, municipalities, and small businesses, adding a million dollars or more in cost and delaying, downsizing, or canceling dozens of projects. Research from IREC, EPRI, Sandia National Laboratories, and the International Energy Agency confirms unintentional islanding from certified inverter-based DERs is vanishingly rare. Per the 2023 EPRI Utility Practices Survey, most utilities skip islanding screening below 1 MW entirely; above that size, a project proceeds to a supplemental Risk of Islanding (ROI) study — and only to DTT if that study confirms the risk. New York extends this same screen-then-study approach up to 5 MW. Dominion diverges on both counts: it screens starting at 250 kW, four times lower than the industry norm, using a stricter 3:1 ratio that fails more readily and skips straight to DTT without the intervening study. APCo imposes a parallel barrier: a telemetry requirement above 200 kW AC, adding an average of $75,000 per project.

Voltage does not explain the gap: Dominion's system commonly operates at 34.5 kV, the same level New York, Illinois, Massachusetts, and Delaware manage under a single standardized process. And the costs fall unevenly, a utility's own interconnection infrastructure is cost-recoverable through ratemaking, while a customer or third-party developer facing the same requirement has no such recovery mechanism, narrowing who can economically pursue DER interconnection and shifting the compliance cost onto ratepayers, the rationale for barring utility affiliates from competing for the same projects below.

3.2 National Models

New York's Standardized Interconnection Requirements (SIR) took a different approach than a purely legislative mandate: a single statewide technical standard, applied uniformly rather than left to each utility's own rules. Systems of 50 kW or less receive expedited review and a hard 10-business-day deadline. New York's "simplified penetration test" checks aggregate DER capacity against a circuit's actual minimum load rather than a flat percentage of peak, the model this paper recommends for replacing Dominion's 3:1 light load screening ratio (Appendix B-2).

Delaware's HB269 offers a legislative template built for durability rather than a one-time fix. It requires electric suppliers to align their interconnection rules with the current IREC Model Interconnection Procedures and to re-adopt each new edition within twelve months of publication, keeping the state's standards current without repeated legislative action (Appendix B-1).

3.3 Recommendation Summary

- Eliminate interconnection barriers for projects at or below 1 MW, and for projects greater than 1 MW and less than or equal to 5 MW, require documented feeder-specific risk, consistent with New York's approach.
- Establish binding permission-to-operate timelines, 30 days residential, 60 days commercial, enforceable by SCC approval.
- Require utilities to publish hosting-capacity maps and constrained-circuit analysis to support transparent, evidence-based screening.
- Build dedicated DER and grid-optimization expertise, and an interconnection ombudsman function, at the SCC.
- Disallow utility company affiliates from competing for BTM solar and/or storage projects to avoid conflicts of interest.

4. Permitting

4.1 Commercial Permitting

Localities apply inconsistent review timelines, documentation requirements, and technical standards to commercial-scale solar projects. This paper recommends Virginia establish an automated, instant-approval pathway for commercial-scale solar, with additional structural and electrical review provisions appropriate to larger systems. A detailed commercial-scale case study, drawing on VA-DSA testimony to the Virginia Department of Housing and Community Development (DHCD), is provided in Appendix C.

4.2 A Permit-Less Category for Low-Risk Devices

Virginia has already established a permitting bypass for one category of DER. HB 395 authorizes certified plug-in solar devices under 1,200 watts to connect directly to a standard outlet without a permit, utility interconnection agreement, or prior utility approval. It also extends DER access to renters and multifamily residents who have no roof of their own to permit.

5. Grid Integration and Virtual Power Plants

5.1 Utility-Led VPPs

Virginia's utility-led VPP framework began with Dominion's pilot under the Community Energy Act and now extends to APCo. HB 1467 directs Phase I utilities to petition for a VPP pilot of up to 150 MW, at least 5 MW of which must come from residential battery storage, with a Commission filing due January 1, 2027. Added to the state's existing 450 MW VPP portfolio, APCo's full 150 MW would bring statewide reliable VPP capacity to 728 MW and increase total modeled ratepayer savings by roughly 7%, to $309.1 million.

Utility-led models elsewhere show what a mature version of this can look like: National Grid's Connected Solutions program, operating across Connecticut, Massachusetts, and New York, pays participating batteries roughly $275 per kW each summer, with a typical 5 kW residential battery earning on the order of $1,000–$1,375 a season. That scale is worth pursuing, but it also carries a caution: an unregulated utility subsidiary positioned to launch its own utility-affiliated VPP program could crowd out independent competition before it has a chance to develop.

That risk may yet be exemplified in Virginia's new largest storage mandate. HB 895 expands Dominion's storage requirement more than fivefold, to 16,000 MW of short-duration and 4,000 MW of long-duration storage by 2045, with APCo adding 780 MW and 520 MW. The bill sets a behind-the-meter goal of 10% for each utility, but that goal is aspirational rather than binding, with no interim milestones enforcing progress before the final deadlines. This paper recommends amending HB 895's 10% BTM goal into a binding requirement for customer or third-party owned BTM storage with interim milestones tied to each utility's existing petition deadlines.

5.2 Non-Utility VPPs

HB 562 authorizes all thirteen of Virginia's electric cooperatives to establish VPP programs beginning January 1, 2027, without requiring Commission approval, opening participation to both direct enrollment and third-party aggregators. Voltus is among the leading national aggregators, with an operating demand-response and storage partnership with Google in Ohio, and is expected to soon announce a Virginia program with a hyperscaler to incentivize approximately 2,000 MW of battery storage. CPower is another of the country's leading aggregators, recognized by grid operators including PJM and NYISO. ODEC's partnership with Tesla shows a working example already operating in Virginia, where BARC Electric Cooperative customers with Tesla Powerwalls can enroll to dispatch stored energy during peak events.

Maryland offers the clearest external model for scaling this track statewide. PSC Order 92-398 establishes a FERC Order 2222 implementation path for third-party VPPs through a public “Green Button” directory of utilities, applications, and providers (Appendix E-1).

5.3 EV School Bus VPP

Virginia’s approximately 17,000 school buses could provide 1,000–1,200 MW of distributed capacity as a Virtual Power Plant (VPP), deployed incrementally over several years rather than waiting 7–10 years for new generation. A statewide program, estimated at $5–6 billion, could be financed through Virginia’s data center electricity consumption fee, federal grants, and reinvested VPP revenues.

School districts should be free to choose a utility-led program, an independent aggregator, or a turnkey provider. Adopting interoperability standards modeled on Maryland and amending Virginia’s VPP statute to guarantee districts the right to participate in PJM and retain VPP revenues—similar to New York’s DER Participation model (Appendix E-3)—would preserve customer choice and competition. Rural and lower-income districts should receive targeted funding and technical assistance, along with incentives for co-located solar, storage, and bidirectional bus charging.

Because school buses already serve a public purpose, they provide a practical foundation for a statewide VPP while also supplying emergency backup power for schools serving as community resilience hubs.

6. Public Awareness and Engagement

6.1 VA-DSA Voter Survey

Durable DER-friendly policy requires public backing that can withstand the General Assembly. In partnership with Deploy Action, VA-DSA plans to conduct a survey of Virginia voters gauging opinion on energy costs, utilities, regulators, and distributed energy resources. Modeled on a comparable survey Deploy Action conducted in California in spring 2026, using the same polling firm, Embold, the Virginia survey will ask 30 questions of 1,000 voters statewide. Results are anticipated in early fall 2026 (Appendix D-1).

6.2 Model Solar PPA and LGA FAQ

Local government attorneys currently evaluate developer solar projects without a shared reference point, slowing procurement and inviting inconsistent, legally overcautious terms across jurisdictions. This paper recommends collaborating with VEPGA and VACO to jointly publish a model solar PPA template alongside a companion FAQ document tailored to Local Government Attorneys (LGAs), giving counsel a vetted starting point rather than a blank page. Standardizing this baseline lets schools and municipalities negotiate from informed terms and move through procurement faster, while still maintaining the procedural diligence public entities require. The Virginia Department of Housing and Community Development (DHCD) could likewise provide training and support to local Building Officials on streamlined and consistent permitting procedures for commercial scale rooftop solar for existing buildings under the Virginia Existing Building Code (VEBC).

7. Workforce Development for Scale

A resilient grid requires a resilient workforce, and the pace of DER deployment recommended throughout this paper depends on having trained installers, inspectors, and technicians available to execute it. Building this workforce pipeline requires action on three fronts. Virginia should coordinate community colleges, high school Career and Technical Education (CTE) programs, and industry partners to align training capacity with the DER deployment pipeline described in this paper. The state should also expand Department of Labor–certified solar and storage apprenticeship programs, paired with wage subsidies and employer incentives, targeted at coalfield communities, dislocated workers, and veterans. Finally, Virginia should link public investment to accountability by requiring apprenticeship or internship participation and local-hiring benchmarks for state-supported solar, storage, and Resilience Fund projects, paired with a workforce incentive adder.

8. A Systems Framework for Implementation: BIRDS

The technical recommendations in Sections 2 through 7 answer what Virginia should do. This section adds a complementary layer, a shared vocabulary, organized around five systems principles (Balance, Interdependence, Regeneration, Diversity, Succession, BIRDS), for explaining why a coherent DER program holds together as a system rather than a list of individual fixes. Table 3 applies each principle to a concrete Virginia action; it is offered for stakeholder and legislative audiences, not as a substitute for the technical analysis above.

Table 3. BIRDS Systems Principles Applied to Virginia

Principle	Core Question	Virginia Application
Balance	*Dominion committed $824.1M in capital but capped its non-wires pilot at $50M — does the incentive reward efficiency as much as it rewards building?*	Pair enhanced ROE for grid-utilization metrics with an automatic step-down once targets are met, so the incentive can't become a permanent capital reward.
Interdependence	*Dominion requires DTT above 250 kW; APCo sets a separate telemetry bar at 200 kW AC — two utilities, two rules, no shared standard. Why should a developer's technical playbook change at the county line?*	Adopt New York's Standardized Interconnection Requirements statewide — already shared across National Grid, Orange & Rockland, and other NY utilities — replacing Dominion's and APCo's rules with one standard and an SCC ombudsman function.
Regeneration	*A dispatched battery costs the grid roughly $800/MWh; a PJM emergency purchase can exceed $1,300/MWh. If a battery is worth more to the grid, why is it paid the same flat rate as a rooftop panel?*	Layer New York's Value Stack (VDER) atop net metering for larger projects, so compensation scales with the value a project actually returns to the grid.
Diversity	*The same barriers block a homeowner's rooftop, a school's array, a hyperscaler's batteries, and electric school buses — will one pathway work for all four?*	Design VPP and incentive rules wide enough for VSSC schools, income-qualified community solar, and hyperscaler models (Section 2.5) as one policy, not three fights.
Succession	*Federal solar tax credits disappear in December 2027 — is Virginia's program built to survive that, or does it quietly assume otherwise?*	Structure incentives on NY-Sun's declining-block model, where the subsidy shrinks as adoption grows — designed to hand off to FERC 2222 market revenue, not depend on the credit indefinitely.

The technical recommendations in Sections 2–7 stand on their own; BIRDS principles are offered as a shared vocabulary for explaining why they function as one coherent system rather than separate fixes.

9. Deployment Roadmap

The recommendations in Sections 2 through 6 are not a single legislative package, they differ in what authority is needed to act on them and how quickly they can move.

Roadmap at a Glance

- 2026: DER Task Force deliberations; Governor's Energy Plan; HB 434 grid utilization metrics reporting begins
- 2027: General Assembly legislative session; SCC regulatory proceedings; VSSC deployment
- 2028–2030: FERC Order 2222 market participation live; statewide VPP market scale-up; DER workforce pipeline maturity

Detailed pathway-by-pathway recommendations follow in Table 4.

Table 4. Recommendations by Implementation Pathway

Pathway	Representative Recommendations
Immediate administrative action (6–12 months)	Utility publication of hosting-capacity maps and constrained-circuit data; SCC dedicated DER staffing and ombudsman function; VA-DSA voter survey; workforce apprenticeship pipeline development; DOE to work with Google to apply Virginia Energy Impact Fund to implement VSSC (to include BESS) in 2026.
Regulatory proceedings	PBR evaluation under HB 903; NSPM expansion to all DERs; SCC to remove interconnection barriers for solar projects at or below 1 MW; Dominion–NextEra merger review as a vehicle for incentive and transparency reform.
2027 legislative session	Net metering cap reform paired with VDER; statewide interconnection standard (NY SIR / Delaware HB269 model); ROE enhanced incentives for utilities; commercial permitting extension; public-entity DER mandate financed via PPA.
Long-term market transformation (2027–2028+)	Large-customer / hyperscaler models (Section 2.5); statewide VPP market maturation aligned with FERC Order 2222 and PJM implementation timelines.

This sequencing tracks the Task Force's own reporting schedule: an Interim Report (November 2026) can capture the immediate actions and flag proceedings underway; a Deployment Report (June 2027) can carry the legislative-track recommendations into the 2027 General Assembly session; and multi-year items, statewide interconnection standards, VPP maturation, large-customer models, should pace to PJM's and FERC's Order 2222 timeline, expected through 2027–2028.

10. Why Virginia Can Lead

Virginia is not starting this transition from a deficit, it holds a combination of assets no other state can claim at once. It hosts the largest concentration of data centers in the world, giving it both the greatest urgency and the greatest leverage to get grid optimization right. It already has strong utility infrastructure, a bipartisan DER Task Force, a cabinet-level Chief Energy Officer, and the foundational clean-energy framework the VCEA built. HB 434 means Virginia has already taken the first concrete step other states are still debating. Its universities and community colleges give it a workforce pipeline ready to scale, and its mature private solar industry means the deployment capacity already exists, what's missing is the coordinated policy framework to direct it. FERC Order 2222's compliance timeline gives Virginia a deadline other states will eventually face too; the state that builds the framework first captures the market, the jobs, and the model other states will look to next.

Virginia's energy system is at an inflection point that its current regulatory model did not anticipate and cannot resolve on its own. The cost pressure on ratepayers is real and near-term; so is the opportunity, created by FERC Order 2222 and by Virginia's own recent legislative progress, to meet that pressure by optimizing the grid Virginia already has rather than building past it.

This paper does not ask the Task Force or the Department to originate new policy from first principles. Every recommendation here has already been demonstrated to work in at least one other state, and each is paired in the appendices with the operating detail needed to adapt it to Virginia. The task ahead is one of adoption and sequencing, not invention, and the roadmap in Section 9 is offered as a starting point for that sequencing, to be refined as the Task Force's own deliberations proceed.

11. About the Virginia Distributed Solar Alliance (VA-DSA)

VA-DSA is organized as a trade association under Section 501(c)(6) of the Internal Revenue Code to advance the interests of Virginia's distributed energy resources ("DER") industry, including distributed solar, storage, and related businesses, public entities seeking to implementor advance DERs in Virginia, non-profits supporting DER in Virginia, DER customers in Virginia and stakeholders, through policy advocacy, regulatory engagement, education, and member collaboration. No part of the Alliance's net earnings shall inure to the benefit of any private member or individual.

Appendices

The appendices below provide the full operating detail behind each recommendation in Sections 2 through 6: administering agency, legislative or regulatory basis, cost mechanics, and (where available) a direct citation to the source proceeding or statute. Several entries remain under active development, consistent with this paper's function as a living reference document for the Task Force rather than a finished legislative text; those are marked accordingly.

Appendix A — Incentives Models

A-1. **ROE Policy Brief** — ratemaking and legal analysis memo by Thompson McMullan supporting a DER-specific utility investment incentive, drawing on Virginia's existing energy-efficiency and performance-incentive precedents.

A-2. **Illinois Shines** — full program model for the commercial-scale, public-entity-inclusive incentive structure referenced in Section 2.4.

A-3. **Massachusetts SMART Program** — declining block structure with storage and brownfield adders, referenced in Sections 2.4 and 5.

A-4. **New York VDER** — commercial DER compensation mechanics referenced in Section 2.3.

A-5. **New York NY-Sun Program** — commercial-scale incentive model referenced in Section 2.4.

A-6. **Unified Benefit-Cost Analysis (NSPM)** — methodology detail supporting the expansion recommended in Section 2.6.

A-7. **Maryland Executive Order 01.01.2025.27** — "Building an Affordable and Reliable Energy Future"**;** non-wires-alternatives evaluation requirement referenced in Section 2.1.

A.8 **Virginia HB 2653 - 2025 Session** — "Qualified Equity and Subordinated Debt Investments Tax Credit" and **§ 58.1-339.4. Qualified equity and subordinated debt investments tax credit.**

Appendix B — Interconnection Models

B-1. **Delaware HB269** — full legislative summary; recommended as Virginia's legislative model in Section 3.2.

B-2. **New York Joint Utilities Interconnection Standards** — detail on the Standardized Interconnection Requirements referenced in Section 3.2.

B-3. **IEEE 1547 vs. DTT** — technical case and SCC hearing history supporting the recommendation in Section 3.1.

Appendix C — Permitting Models

C-1. **[Commercial Permitting Proposal]** — VA-DSA permitting proposal to amend the Virginia Existing Building Code (VEBC) as recommended in Section 4.2, as a proposed Task Force deliverable.

Appendix D — Public Awareness Models

D-1. **[Deploy Action California Survey]** — methodology and results from the spring 2026 California voter survey that the VA-DSA survey described in Section 6.1 is modeled on.

Appendix E — Grid Integration & VPP Models

E-1. Maryland PSC Order 92398 —VPP/FERC Order 2222 implementation, DER Registry integration referenced in Section 5.2.

E-2. **Maryland Interoperability and Integration Project** — open data standards preventing vendor lock-in, referenced in Section 5.3.

E-3. **NYISO DER Participation Model** — permits aggregators to bid directly into wholesale markets, referenced in Section 5.3.

Appendix F — VSSC Program

F-1. **Virginia Solar for Schools & Communities (VSSC) Program** — as described in Section 2.2

Appendix G — Sources and Citations

Citations for statistics and claims not already covered by an operating-model appendix above (Appendices A–F).

G-1. **Virginia HB 434** (Chapter 611, approved April 13, 2026) — requires Phase I and Phase II utilities to petition the SCC for approval of electric grid utilization metrics and to evaluate non-wires alternatives, including DERs, storage, and virtual power plants.

G-2. **The Brattle Group, "The Untapped Grid: How a Better Utilized Power System Can Improve Energy Affordability"** (March 2026) — finding that a 10% improvement in system utilization reduces rates by 3.4%, increases utility earnings by 23%, and accelerates new-load connection by several years relative to current levels.

G-3. **The Brattle Group, "The Untapped Grid"** (March 2026) — estimate of $110–180 billion in national consumer savings over ten years from improved grid utilization relative to a business-as-usual capacity build-out.

G-4. **The Pew Charitable Trusts, "Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future"** (April 2026) — projected 78% growth in U.S. electricity demand between 2023 and 2050;

G-5. **The Pew Charitable Trusts, “Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future”** (April 2026) — approximately 1 in 6 households were behind on utility bills in 2026.

G-6. **JLARC, “Data Centers in Virginia”** (December 2024) — residential bills could climb by more than $400 a year by 2040 if left unaddressed.

G-7. **Virginia Department of Education, “Pupil Transportation”** — Virginia’s roughly 17,000 school buses…

G-8. **VA SCC, "SCC Approves Dominion Grid-Transformation Plan"** (September 2023) — the SCC approved $824.1 million in capital investment and $58.6 million in operations and maintenance. The plan's first non-wires-alternative pilot, by contrast, covers just five battery storage systems over five years.

G-9. **Current Energy Group, “Post-Legislative Retrospective Memo Report Addendum”** — projected to add 188 MW of reliable DER capacity