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# Legal Report on Executive Order 43


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## Clean energy legislation: Help or hinder?

This report, prepared by the Environmental and Regulatory Law Clinic at the University of Virginia School of Law, evaluates existing laws and regulations that will either aid or hinder Virginia in meeting its decarbonization targets. Clean energy policy initiatives, including regulatory innovations in Virginia and other states, are also assessed.

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# CHAPTER 1:
# EXECUTIVE SUMMARY

## I. Introduction

On September 16, 2019, Virginia Governor Ralph Northam signed Executive Order 43, which directed the Department of Mines, Minerals and Energy ("DMME"), in consultation with the Secretary of Commerce and Trade, the Secretary of Natural Resources, and the Director of the Department of Environmental Quality ("DEQ"), to develop a plan that would guide Virginia toward producing 30% of its electricity from renewable energy sources by 2030 and 100% carbon-free sources by 2050.

Executive Order 43 did not write on a blank slate. Indeed, it followed up on then-Governor Tim Kaine's Executive Order establishing Virginia's first Governor's Commission on Climate Change (2007), former Governor Terry McAuliffe's creation of Virginia's Climate Change and Resiliency Update Commission (2014), Governor McAuliffe's Executive Order 57 (2016) on the "Development of Carbon Reduction Strategies for Electric Power Generation Facilities," and Governor McAuliffe's Executive Directive 11 (2017) aimed at "Reducing Carbon Dioxide Emissions from Electric Power Facilities and Growing Virginia Clean Energy Economy."

In sum, the targets established by Executive Order 43 were thoughtfully debated for more than a decade and were developed through the work of three different gubernatorial administrations. The focus now turns to implementation.

This Legal Report on Executive Order 43 evaluates two questions: (1) what are the existing laws and regulations on the books today that will aid Virginia in meeting its decarbonization targets; and (2) what existing laws and regulations may (intentionally or not) pose barriers to implementation. To consider these questions, the Legal Report assesses several clean-energy policy initiatives, including regulatory innovations in Virginia and other states. It is organized into five chapters, as follows:

## II. Summary of the Chapters

### *Chapter 2: Review of Legislation from the 2020 Virginia General Assembly*

Chapter 2 was primarily authored by Brian Masterson. It provides an overview of legislation introduced during the 2020 Virginia General Assembly related to renewable energy development, energy efficiency, and the transition to clean energy.

The most significant piece of legislation enacted by in 2020, undoubtedly, is the Virginia Clean Economy Act ("VCEA"). Indeed, it is the most significant piece of clean energy legislation ever enacted in Virginia's history. It (along with other, related legislation) establishes: (1) a binding renewable portfolio standard for Virginia's two largest investor-owned electric utilities (Dominion Energy and Appalachian Power); (2) energy-efficiency savings targets that must be achieved before new carbon-emitting sources can be permitting; and (3) a cap-and-trade mechanism to leverage market forces to drive down costs and build on prior efforts to link Virginia to the Regional Greenhouse Gas Initiative ("RGGI").

In addition to developing these three pillars (renewable energy, energy efficiency, and market-based trading), the 2020 General Assembly also addressed the "soft costs" of clean energy development, such as local tax policies, zoning, and financing, all of which can restrict the roll out of renewable energy facilities to less than what the market would otherwise bear. The legislature also drafted bills on non-utility distributed generation so that individual homeowners, businesses, and smaller independent power providers can contribute directly to developing a zero-carbon grid. Finally, to ensure that no Virginian is left behind in the transition to cleaner and healthy electricity, the General Assembly took up several bills on environmental justice concerns.

The 2020 General Assembly also authorized a handful of studies, implicitly recognizing that the transition to a carbon-free grid by 2050 will necessarily require review of the progress made under the VCEA, revaluation of benchmarks, and revisions to the statutory scheme in future years.

### *Chapter 3: Regulation of Utilities by the State Corporation Commission*

Chapter 3 was primarily authored by Nicole Pidala and Laura Friedli. It looks at the work that will be needed before the Virginia State Corporation Commission to achieve the targets outlined in Executive Order 43. To be sure, the carbon pollution from coal- and natural gas-fired power plants will be regulated by the Virginia Department of Environmental Quality under Virginia's State Air Pollution Control Law. But where the "rubber meets the road" – in terms of retiring old, heavily polluting fossil generation and approving the construction of new, zero-carbon renewable generation – is often at the State Corporation Commission.

The Commission will oversee the progress of investor-owned utilities to meet the renewable portfolio standard targets of the VCEA, but will also have an important role to play in regulating retail competition from non-utility power providers. In addition to popular programs for net-metering and competitive service provides, Virginia law also allows for community aggregation, through which municipalities may procure their own portfolio of renewable resources as an alternative to receiving service from an incumbent, investor-owned utility. All of these non-utility options hold the promise of directly increasing the amount of zero-carbon, renewable energy contributing to the electricity grid in Virginia.

Perhaps most importantly, under the VCEA, the Commission will have to account for the "social cost of carbon" before approving or rejecting any newly proposed electricity generating facility. Yet the Commission does not yet have guidance or regulations on how the cost will be calculated or how the calculation will be applied in the decision-making process. In short, there are critical decisions before the State Corporation related to the social cost of carbon that could either inhibit or accelerate the transition to clean energy.

### *Chapter 4: The Role of the Federal Energy Regulatory Commission and PJM*

Chapter 4 was primarily authored by Andrew Kriha. It looks outside Virginia at the role of the Federal Energy Regulatory Commission ("FERC") and PJM Interconnection ("PJM"). PJM is the regional transmission organization that manages the movement of electricity across all or parts of thirteen states (including Virginia) and the District of Columbia. FERC is an independent, federal agency that oversees the interstate transmission of electricity and, in the process, regulates PJM.

Most importantly, Chapter 4 warns that recent and ongoing FERC and PJM actions threaten Virginia's ability to decarbonize the Commonwealth's electricity grid. In December 2019, FERC issued announced that its Minimum Offer Price Rule ("MOPR") would be expanded to impose cost-related restrictions on any resources benefitting from a "state subsidy," and intimated that a mandatory Renewable Portfolio Standard could be treated by FERC as such a subsidy. If Dominion Energy's renewable resources do not clear market because of application of the MOPR, the utility could be forced to purchase duplicative, out-of-state carbon-polluting generation on top of the renewable purchases needed to meet the targets in the VCEA.

Concerns over application of the MOPR highlight larger, structural issues with the way that PJM manages capacity markets that appear to disadvantage renewable options. Notably, PJM is the *only* regional transmission organization in the nation to have added more carbon-pollution sources than renewable sources to the generation mix since 2012. This chapter includes options that the Commonwealth may wish to explore both within—and outside of—PJM.

### *Chapter 5: Approaches to Decarbonization in Other States*

Chapter 5 was primarily authored by Brian Masterson. It concludes this Legal Report with a look at actions other states have taken to move to a zero-carbon electricity grid. At the time of this writing, twelve states (including Virginia), the District of Columbia, and Puerto Rico have adopted zero-carbon initiatives. Collectively, these jurisdictions account for one-third of the country's population, demonstrating that there is significant momentum in the United States in developing carbon-free energy.

The chapter observes a handful of commonalities among the states. First, all of states moving toward a zero-carbon target are taking a multi-faceted approach to reach their goals. That is, they have several, overlapping regulatory regimes all helping to drive the development of a cleaner greener, grid. They may have renewable portfolio standards, carbon pricing regimes (*i.e.,* carbon trading), requirements on energy efficiency, programs to promote non-utility distributed generation, and requirements for utilities to internalize the costs of carbon pollution (*i.e.,* to use a social cost of carbon calculation). Second, every state marries these overlapping policies with a strong enforcement mechanism to ensure that targets are met, and met on schedule.

## III. Conclusion

The overarching takeaway from this Legal Report is that significant groundwork has already been set in Virginia to meet the goals in Executive Order 43, but much work remains to be done. The Virginia Clean Economy Act is a remarkable achievement that will prove essential to the goal of decarbonization, but it cannot run on autopilot. Legal roadblocks could appear in permitting decisions at the Virginia Department of Environmental Quality, proceedings before the State Corporation Commission, at PJM Interconnection, and at the Federal Energy Regulatory Commission. Given the long-term (thirty year) timeframe set out in Executive Order 43, additional study and legislative revisions will almost certainly prove necessary to keep Virginia on pace.

Cale Jaffe
*Editor and Supervisor for the Legal Report on Executive Order 43*

# CHAPTER 2:
# REVIEW OF LEGISLATION FROM THE 2020 VIRGINIA GENERAL ASSEMBLY

Executive Order 43 ("E.O. 43") sets targets that Virginia "produce thirty percent of [its] electricity from renewable energy sources by 2030 and one hundred percent of [its] electricity from carbon-free sources by 2050." The order identifies five areas of emphasis in meeting these targets: solar and onshore wind energy, energy efficiency, offshore wind, energy storage, and energy equity. A large number of bills that were passed during the 2020 Session of the General Assembly address the objectives of E.O. 43 and will aid in its implementation. A few bills from the 2020 Session, none of which passed, would impede the order if revisited by the General Assembly in future years. This Chapter of the report provides an analysis of all of these bills (positive and negative), divided into the following categories:

1. Virginia Clean Economy Act
2. Regional Greenhouse Gas Initiative
3. Energy Efficiency
4. "Soft Costs" of Clean Energy Development
5. Distributed Generation
6. Environmental Justice and Transition to Clean Energy
7. Studies, Reports, Task Forces and the Commonwealth Energy Policy
8. Continued to 2021 Session

## I. Virginia Clean Economy Act

For the purposes of E.O. 43, the Virginia Clean Economy Act ("VCEA"), enacted through H.B. 1526 and other companion legislation, is the single most important piece of legislation passed this session. The VCEA makes a number of significant changes to energy regulation in Virginia. These include creating a mandatory renewable portfolio standard and accompanying renewable energy procurement targets, directing the Commonwealth to join RGGI or create an emission trading program of its own, improving energy efficiency programs including requirements to meet energy efficiency targets before constructing any new carbon-emitting sources, increasing access to net-metering, and encouraging competitive procurement of renewable energy sources.

All of these programs will play a significant role in meeting E.O. 43's targets. While there will likely be efforts to strength, weaken, or modify the Act in future years, it is critical that the Act's core structure remain intact if Virginia is to achieve a zero-carbon energy sector by 2050.

In particular, four key mandates must remain in place: (1) the renewable portfolio targets; (2) the emissions trading program, such as RGGI; (3) the energy efficiency targets; and (4) the draw-down on carbon-emitting sources. Without these legislative mandates, Virginia will not be able to achieve E.O. 43's ambitious objectives. Existing law does not provide state agencies with sufficient authority to achieve these objectives. A more detailed discussion of the VCEA's specific measures follows.

First, the VCEA adds a new section entitled "Generation of electricity from renewable and zero carbon sources" to the Virginia Code. This section contains a mandatory renewable portfolio standard as well as a schedule for the retirement of generation facilities that emit greenhouse gases. Most coal plants and oil plants are phased out by 2024, biomass generating units (except the Virginia City Hybrid Energy Center ("VCHEC"), which co-fires with coal) are phased out by 2028, and all carbon-emitting generating units (including VCHEC) are phased out by 2045.

Virginia's pre-existing definition of "renewable energy" in Va. Code § 56-576 has long included sources that emit greenhouse gas pollution, including biomass "sustainable or otherwise", landfill gas, and waste-to-energy. Through 2025, the renewable portfolio standard uses that pre-existing definition of renewable energy found in Va. Code § 56-576 but excludes some sources that meet the current definition. The renewable energy definition expressly excludes "waste heat from fossil-fired facilities" and "electricity generated from pumped storage," such as Dominion's Bath County unit. During this initial period, renewable energy may either come from facilities located within Virginia or the PJM Interconnection region.

Starting in 2025, eligible sources are wind, solar, utility hydropower in use before 2020, some non-utility hydropower, waste-to-energy or landfill gas in use before 2020 that does not use fossil fuels or woody biomass, and biomass facilities in use before 2020 that primarily power the entity to which they are interconnected. The amount of qualifying energy from biomass is capped at the lesser of the 2019 electricity production and the current electricity production. Expressed as percentage of the previous year's production, the portfolio standard targets are depicted on the following page.

To promote distributed generation across the grid, Dominion must obtain one percent of its renewable energy requirement from projects that are less than 1 megawatt and that produce less than 3 megawatts at that location. Dominion must also obtain one-quarter of one percent of its requirement from "low-income qualifying projects," such as solar energy projects in communities where at least 50% of the electric output serves low-income utility customers. Beginning in 2025, 75 percent of Dominion's renewable energy certificate allowances must come from sources within Virginia (a requirement that might raise dormant Commerce Clause concerns).[1] If a utility exceeds its requirement, that utility may carry the excess renewable energy forward for five years.

A utility that fails to meet its renewable portfolio requirement must make a deficiency payment of $45/megawatt-hour. (The deficiency payment would be $75/megawatt-hour for Dominion if it

[1] *See Appalachian Voices v. State Corp. Comm'n,* 675 S.E.2d 458, 462-63 (Va. 2009) (rejecting a dormant Commerce Clause challenge to Va. Code § 56-585.1(A)(6) and the requirement for certain coal plants to "utilize[] Virginia coal."). The court distinguished the Virginia law from an Oklahoma statute that had been stricken as unconstitutional by the Supreme Court of the United States because it required utilities to use fuel "containing at least ten percent Oklahoma-mined coal." *Id.* at 462. The Virginia Supreme Court explained, "Unlike the Oklahoma statute at issue in *Wyoming v. Oklahoma* which prescribed use of a ten percent mixture of Oklahoma coal in coal-fired plants in state, nothing in the Virginia statute requires the use of Virginia coal. What is required is the technology to be able to burn coal found in Virginia. Consequently, the phrase "utilizes Virginia coal" is descriptive and not prescriptive in content." *Id.* at 462.

fails to meet the requirement for projects under one megawatt.) The amount of the deficiency payment effectively puts a cap on the cost of compliance with the portfolio standard.

| Appalachian Power | | Dominion | |
|---|---|---|---|
| Year | Requirement | Year | Requirement |
| 2021 | 6% | 2021 | 14% |
| 2022 | 7% | 2022 | 17% |
| 2023 | 8% | 2023 | 20% |
| 2024 | 10% | 2024 | 23% |
| 2025 | 14% | 2025 | 26% |
| 2026 | 17% | 2026 | 29% |
| 2027 | 20% | 2027 | 32% |
| 2028 | 24% | 2028 | 35% |
| 2029 | 27% | 2029 | 38% |
| 2030 | 30% | 2030 | 41% |
| 2031 | 33% | 2031 | 45% |
| 2032 | 36% | 2032 | 49% |
| 2033 | 39% | 2033 | 52% |
| 2034 | 42% | 2034 | 55% |
| 2035 | 45% | 2035 | 59% |
| 2036 | 53% | 2036 | 63% |
| 2037 | 53% | 2037 | 67% |
| 2038 | 57% | 2038 | 71% |
| 2039 | 61% | 2039 | 75% |
| 2040 | 65% | 2040 | 79% |
| 2041 | 68% | 2041 | 83% |
| 2042 | 71% | 2042 | 87% |
| 2043 | 74% | 2043 | 91% |
| 2044 | 77% | 2044 | 95% |
| 2045 | 80% | 2045 and thereafter | 100% |
| 2046 | 84% | | |
| 2047 | 88% | | |
| 2048 | 92% | | |
| 2049 | 96% | | |
| 2050 and thereafter | 100% | | |

A utility will make a deficiency payment rather than obtain additional renewable energy if it is cheaper to do so. Thus, to achieve the goals of E.O. 43, it is important that the deficiency payment not be set too low.[2] The deficiency payments grow by one percent annually, which gives the

[2] Several other states have set the equivalent penalty for non-compliance with their renewable portfolio standard at $50/megawatt-hour but do not provide for the penalty to grow over time. *See, e.g.,* D.C. Code § 34-1434(c)(1). Though $50/megawatt-hour is the most common penalty, there is considerable variation across states. *Compare* Wash. Rev. Code. § 19.405.090(1)(a) (setting the penalty as high as $150/megawatt-hour for coal-fired resources) *with* Order Relating to RPS Penalties, *Proceeding To Examine Hawaii's Renewable Portfolio Standards Law*, Docket No. 2007-0008 (Dec. 19, 2008) (setting the penalty at $20/megawatt-hour).

Commonwealth a significant "hammer" to insist on compliance with the renewable targets. Although the intent of the statute is to achieve compliance without the need for deficiency payments, if those payments are made the proceeds would be allocated to job training in disadvantaged communities (50%), energy efficiency of public buildings (30%), renewable energy in disadvantaged communities (12%), and program administration (4%). All costs of compliance with the renewable portfolio standard and associated procurement requirements, including deficiency payments, are recoverable from customers through a non-bypassable charge (except for percentage-of-income customers).

In addition to the renewable portfolio standard, this section specifies procurement targets for renewable installations and energy storage, as follows:

| Appalachian | | Dominion | |
|---|---|---|---|
| 2023 | 200 MW onshore wind or solar<br>(70 MW purchased from third parties) | 2024 | 3,000 MW onshore wind or solar<br>(1,050 MW purchased from third parties) |
| 2027 | 200 MW additional onshore wind or solar<br>(70 MW purchased from third parties) | 2027 | 3,000 MW additional onshore wind or solar<br>(1,050 MW purchased from third parties) |
| 2030 | 200 MW additional onshore wind or solar<br>(70 MW purchased from third parties) | 2030 | 4,000 MW additional onshore wind or solar<br>(1,200 MW purchased from third parties) |
| 2035 | 400 MW energy storage<br>(Maximum project size: 500 MW) | 2035 | 6,100 MW additional onshore wind or solar<br>(2,135 MW purchased from third parties)<br>2,700 MW energy storage<br>(Maximum project size: 800 MW) |

Of Dominion's procurement requirement, 1,100 megawatts must be from projects of less than three megawatts. A utility may petition the Commission to procure beyond these requirements. In addition, to promote competition and reduce costs for customers, both utilities must conduct an annual request for proposals for the construction of onshore wind, solar, and energy storage projects.

Building on prior efforts to link Virginia to the Regional Greenhouse Gas Initiative ("RGGI"), the VCEA directs the State Air Pollution Control Board to develop regulations by 2024 that will reduce carbon dioxide emissions from the electricity generation to zero by 2050. The Board may use the existing RGGI regulations (9 VAC §§ 5-140-6010 to 5-140-6440) provided that no allowances are issued after 2049 and that the regulations do not allow "emission offsetting or netting based on fuel type."[3] The program may include market mechanisms such as trading and banking of allowances. Any new regulations that might be drafted would remain, of course, subject to the public notice and comment requirements of the Virginia Administrative Process Act.

The VCEA also restructures how utilities recover costs for energy efficiency programs. It eliminates the existing process for seeking a margin on operating expenses and net lost revenues at the time of program design and approval (unless the utility's rate of return falls significantly), but adds the cost of pilot programs as recoverable. To make sure that efficiency programs actually

[3] This language appears to allow offsets as long as they are not "based on fuel type." For example, the program could use offsets for "submerged aquatic vegetation restoration" as envisioned by S.B. 783.

deliver the savings anticipated, beginning in 2022 a utility would only recover a margin on operating costs and pilot programs if it met the energy efficiency targets of Va. Code § 56-596.2. Utilities that exceed their targets would be eligible to recover a performance incentive of 20 basis points for each tenth of a percentage point by which they exceed their target. The performance incentive cannot exceed 10 percent of the utility's spending on energy efficiency programs, however.

The energy efficiency targets as a percentage of 2019 jurisdictional retail sales are:

| | Appalachian Power | Dominion |
|---|---|---|
| 2022 | 0.5% | 1.25% |
| 2023 | 1.0% | 2.5% |
| 2024 | 1.5% | 3.75% |
| 2025 | 2.0% | 5% |

To the extent that energy savings would undermine utility earnings, the VCEA would allow those questions to be addressed as true-up costs in a routine ratemaking case. Further, beginning in 2026, the State Corporation Commission would be directed to set new efficiency targets. The COVID-19 pandemic will likely interfere with utilities' ability to implement to implement in-person energy efficiency programs.[4] The associated economic disruption and changes in daily routines under the norms of social distancing may make it difficult to accurately measure energy savings attributable to efficiency measures. Once state-at-home orders can be safely lifted, however, implementation of utility-sponsored efficiency programs will play an important role in helping weatherization provides and other small businesses get back in touch with their customers and rebuild their businesses.

Large general service customers have historically been exempted from Virginia's efficiency programs, but that is no longer the case under the VCEA. Instead, these major commercial/industrial customers would have to seek approval to "opt out." To opt out, they must demonstrate that they have implemented their own energy efficiency programs that "have produced or will produce measured and verified results consistent with industry standards." The threshold for classification as a large general service customer is doubled from 500 kilowatts to one megawatt of demand.

Critically, the VCEA puts significant restrictions on the construction of any newly proposed power plant that would emit greenhouse gases as a byproduct of generating electricity. The Commission cannot approve the construction of new generation facilities that emit greenhouse gases unless it finds that there is "a threat to the reliability or security of electric service to the utility's customers" and that "supply-side resources are more cost-effective than demand-side or energy storage resources." Even if it makes such findings, a utility may only construct the facility if it has first met the energy saving mandates described above. In the application to construct "any new facility",

[4] *See* Direct Testimony of Jim Grevatt, Appalachian Voices and Natural Resources Defense Council, *Petition of Va. Elec. & Power Company re: 2019 DSM Update,* PUR-2019-00201 (filed Mar. 20, 2020)

the Commission must also consider the social cost of carbon[5] "as a benefit or a cost." Thus, the social cost of carbon will be factored into the permitting decision for future conventional and renewable projects. Collectively, these requirements address a long-running concern from environmental organizations that energy efficiency programs and smaller-scale distributed solar energy projects were often criticized as being "too little, too late" to delay or avoid the approval of massive, new coal-and gas-fired power plants. The changes to the VCEA require that utilities begin investing in these alternatives earlier in the planning process.

As part of the draw-down of fossil fuel generation, the VCEA also commissions a report to the General Assembly due by January 1, 2022 that includes a recommendation on "whether the General Assembly should permanently repeal the ability to obtain a certificate of public convenience and necessity for any electric generating unit that emits carbon as a by-product of combusting fuel to generate electricity." Until then, the State Corporation Commission is prohibited from issuing certificates of public convenience and necessity to such generating units.

Further, the VCEA adjusts a utility's ability to recover costs. It allows utilities to recover the costs of mitigating the impacts of offshore wind development on marine life and the costs of purchasing allowances in emissions trading programs. It eliminates the 100 basis point enhanced rate of return for new nuclear and offshore wind projects, while also raising the aggregate cap on onshore wind and solar facilities deemed in the public interest and eligible for an enhanced rate of return from 5,000 megawatts to 16,100 megawatts. It also raises the aggregate cap for offshore wind to 3,000 megawatts, and doubles the aggregate cap for rooftop solar from 50 megawatts to 100 megawatts.

To accelerate the State Corporation Commission's approval process for renewable energy projects, the VCEA deems certain projects as automatically in "the public interest." These include 2,700 megawatts of energy storage, of which 35% must be purchased from third parties, 5,200 megawatts of offshore wind, and offshore wind facilities between 2,500 and 3,000 megawatts owned and operated by Dominion. The energy storage is subject to a competitive procurement process, although up to 25% may be selected for non-price criteria such as geographic distribution or areas of high need.

The offshore wind projects are "subject to competitive procurement or solicitation for a substantial majority of the services and equipment, exclusive of interconnection costs, associated with the facility's construction." For the Dominion owned and operated projects, cost recovery is presumed if the project meets the competitive procurement requirements and "the project's projected total levelized cost of energy, including any tax credit, on a cost per megawatt hour basis, inclusive of the costs of transmission and distribution facilities associated with the facility's interconnection, does not exceed 1.4 times the comparable cost, on an unweighted average basis, of a conventional

[5] *See* New York University School of Law, Institute for Policy Integrity, *Social Costs of Greenhouse Gases* (Feb. 2017), https://policyintegrity.org/files/publications/Social_Cost_of_Greenhouse_Gases_Factsheet.pdf; Matt Butner, *et al.*, New York University School of Law, Institute for Policy Integrity, *Carbon Pricing in Wholesale Electricity Markets: An Economic and Legal Guide* (Mar. 2020), https://policyintegrity.org/files/publications/Carbon_Pricing_in_Wholesale_Electricity_Markets_Report.pdf

simple cycle combustion turbine generating facility as estimated by the U.S. Energy Information Administration in its Annual Energy Outlook 2019." Dominion's utility-owned offshore wind projects are not eligible for an enhanced rate of return.

To encourage Dominion to seek out bilateral contracts to offset costs that would otherwise be borne by ratepayers, the legislation allows Dominion to allocate a portion of an offshore wind facility's capacity to qualifying large general service customers. All offshore wind projects must also submit an environmental and fisheries mitigation plan as well as quarterly reports on the progress of construction.

The VCEA also establishes a percentage-of-income payment program to address worries about how the transition to clean energy might impact electricity rates for low income households. The program would limit electricity costs to 6% of a customer's income or to 10% for customers with electric heating. The program also seeks to provide weatherization and energy efficiency programs to low-income households. The State Corporation Commission must issue its final order establishing the program by the end of 2020.

Given that much of the solar energy development in Virginia to-date has been through voluntary net-metering, it is not surprising that the VCEA makes some adjustments to the Commonwealth's net-metering program. It increases the eligibility cap from 20 to 25 kilowatts for residential customers and from 1 megawatt to 3 megawatts for non-residential customers and relaxes the required parity between expected consumption and generation for Dominion customers. Critically, the bill also increases the systemwide cap from 1% to 6%, of which one percentage point is dedicated exclusively to low-income customers. Utilities had previously insisted on a stingy cap for net-metering, arguing that net-metered customers pay less than traditional customers for fixed charges like transmission and distribution line maintenance and construction. Responding to this concern, the VCEA requires the Commission to commence a net-metering ratemaking proceeding in 2024, or when aggregate net-metering reaches 3%. If the final order from this proceeding results in less compensation for net-metering, low-income customers may still net-meter under the pre-existing terms if those terms are more favorable.

Finally, the VCEA raises the caps for the power purchase agreement pilot program.[6] It raises Dominion's aggregate cap from 50 megawatts to 500 megawatts for jurisdictional customers and 500 megawatts for non-jurisdictional customers. It also raises Appalachian Power's aggregate cap from 7 megawatts to 40 megawatts. The maximum project size is now 3 megawatts. Going forward, the minimum project size (50 kilowatts) applies to neither non-profits nor low-income customers.

On the whole, the VCEA represents the General Assembly's most direct and comprehensive response to E.O. 43. As such, it contains many of the policies essential to achieving a zero-carbon energy sector by 2050. The VCEA institutes a mandatory renewable portfolio standard, places

[6] 2013 Va. Acts of Assembly Ch. 358 and 382, § 1 (as amended by 2017 Va. Acts of Assembly Ch. 803)

restrictions on new fossil fuel plants, creates a timeline for phasing out existing fossil fuel plants, increases competitive procurement of renewable energy sources, and overhauls Virginia's weak energy efficiency programs. In addition, it expands existing net-metering programs so that customers, not just utilities, can hasten the transition to renewable energy. These are all crucial steps on the path to zero-carbon energy envisioned by E.O. 43. However, over the next few years, the effects of the COVID-19 pandemic may distort the VCEA's targets by temporarily reducing electricity usage, possibly making it easier for utilities to comply through business as usual.

## II. Regional Greenhouse Gas Initiative ("RGGI")

Several bills direct the Virginia Department of Environmental Quality to implement 9 VAC §§ 5-140-6010 to 5-140-6440, which is the regulation finalized in 2019 designed to link Virginia to the RGGI program. Funding for the existing RGGI regulations was blocked by the 2019 General Assembly. The Governor's proposed budget for 2020, however, included provisions specifically to remove that block.[7] Accordingly, the program can now begin to be implemented.

In its definition of "consignment auction", the carbon dioxide emissions trading regulations state: "auction revenue is returned to CO2 budget sources … in accordance with procedures established by [DMME]."[8] Under the current emissions trading program, the holders of conditional allowances must consign them to a quarterly consignment auction,[9] but DEQ may elect to participate in a direct auction, which is defined to include RGGI auctions, instead of a consignment auction "in accordance with requirements established by the Virginia General Assembly."[10] This regulatory language allows Virginia to fully join RGGI if given authorization by the General Assembly. Such authorization has now passed by houses of the legislature.

The legislation related to RGGI all contains an identical authorization: "The Director is hereby authorized to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article."[11] In addition, the RGGI bills allow DEQ to hold the proceeds of allowance auctions in an interest-bearing account and make appropriations from this account in accordance with the bill's allocation "[t]o the extent permitted by Article X, Section 7 of the Constitution of Virginia."[12]

Other legislation similarly sets the stage for participating in RGGI in full, but with particular policy preferences for how to manage that participation. For example, H.B. 981/S.B. 1027 directs DEQ to implement 9 VAC §§ 5-140-6010 to 5-140-6440, which link Virginia to RGGI, and authorizes the development of an auction program to sell allowances into RGGI. Importantly, 50% of the proceeds from the sale of allowances are allocated to low-income energy efficiency programs

[7] *See* H.B. 29, Virginia General Assembly, 2020 Legislative Session, (enrolled text of the budget bill striking Item 4-5.11, which had imposed limitations on the use of state funds to support participation in RGGI), https://budget.lis.virginia.gov/item/2020/1/hb29/enrolled/4/4-5.11/

[8] 9 VAC § 5-140-6020

[9] *See* 9 VAC § 5-140-6430

[10] 9 VAC § 5-140-6435

[11] *See, e.g.,* H.B. 981 (enrolled text), http://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+HB981ER

[12] *See* H.B. 20; H.B. 1152; H.B. 981

while 45% of proceeds are primarily allocated to "assisting localities and their residents affected by recurrent flooding, sea level rise, and flooding from severe weather events."

Finally, under H.B. 981, investor-owned utilities would be entitled to recover the costs of compliance with the emissions trading program as "environmental project compliance costs" pursuant to subdivision (A)(5)(e) of Va. Code § 56-585.1, meaning that these costs would be borne by ratepayers instead of a utility's shareholders.

Legislation, such as H.B. 981, that allows Virginia to join RGGI in full is necessary to fulfill the VCEA's mandate to participate in an emissions trading program. Along with the VCEA's additional requirements for operating the program, this legislation will be essential to ensuring that the drawn-down of carbon-emitting sources occurs in a cost-effective manner.

## III. Energy Efficiency

Energy efficiency is recognized as the cheapest option for meeting a customer's energy-service needs. That is, electricity customers are focused on the services that electricity provides—a comfortable home, a well-lighted room, and food that is kept fresh in a refrigerator, etc. These are the services that customers are happy to pay for. Yet outside of purely decoupled electricity markets, this is not how energy services are sold. Rather, in Virginia, as in many other jurisdictions, electricity is sold as a product in its own right, by the kilowatt-hour. Yet customers are not interested in paying for electricity just to purchase kilowatt-hours. They are interested in receiving energy services at the lowest possible cost. That is where cost-effective energy efficiency programs come into play. As is often said, the cheapest kilowatt-hour is the one you never have to buy in the first place.

Most of the bills discussed below seek to modify the energy efficiency programs of Va. Code § 56-596.2. In particular, they strengthen the stakeholder process to include verification of efficiency savings, require large general service customers to adopt efficiency programs in exchange for their exemption from rate adjustments that cover the costs of utilities' efficiency programs, and create performance incentives for exceeding new mandatory efficiency savings targets. In a different vein, S.B. 963 seeks to promote energy efficiency on government property. The bill requires state agencies to track the water and energy consumption of their buildings and identify buildings with a high priority for efficiency upgrades. Other bills impacting the development are as follows:

- H.B. 575 strengthens the stakeholder process that utilities must conduct as part their energy efficiency programs.[13] The process must now include input and feedback on compliance and its effect on IRPs, policy reforms that can "ensure maximum and cost-effective deployment of energy efficiency technology," and "best practices for evaluation, measurement, and verification for the purposes of assessing compliance" in addition to feedback on the programs' development.

- H.B. 1576 allows a large general service to opt of their utility's energy efficiency programs only if the customer "has, at the customer's own expense, implemented energy efficiency programs that have produced or will produce measured and verified results consistent with

[13] *See* Va. Code § 56-596.2 (requiring utilities to consult stakeholders in developing energy efficiency programs)

industry standards." Under current law, utilities cannot charge large general service customers for energy efficiency programs, but there is no requirement that the customer have equivalent efficiency programs in place.[14] The bill also adjusts the definition of "large general service customer" from 500 kilowatts at a single meter to one megawatt at a single site. This provision is incorporated into the VCEA.

- S.B. 963 requires each state agency to designate an "energy manager." The energy manager is responsible for maintaining a list of buildings owned or leased by the agency and their energy usage and for identifying buildings or spaces for energy audits and energy saving performance contracts.

- S.B. 754 authorizes electric cooperatives to offer, without SCC approval, a program in which customers can receive energy efficiency upgrades through an on-bill tariff. Such programs are reviewable by the SCC at regular ratemaking proceeding. After the energy saving devices are installed, customers will receive an energy savings charge as separate line item on their electricity bills. The cooperative may continue to charge subsequent customers on the same premises though the current customer must give notice of the charge. By law, the program must "result in deemed savings that are reasonably projected, based on the customer's electricity utilization and rates at the beginning of the term, to result in lower electric bills for the customer."

Energy efficiency programs will play a significant role in the transition from fossil fuels to carbon-free energy. Indeed, even when compared to cost-effective renewable energy generation with zero fuel costs (e.g., wind and solar generation), reducing energy demand through well-designed efficiency programs remains a less expensive option.[15]

And yet, Virginia has lagged significantly behind the nation's leaders in taking advantage of the savings available with demand-side management programs. In 2007, Virginia adopted a 10% cumulative energy savings goal, to be achieved by 2022. In Dominion's jurisdictional service territory, the Commonwealth has only achieved 3.8% of that target.[16] Further documenting Virginia's laggard performance has been the American Council for an Energy Efficiency's Utility Scorecard.[17] The 2020 edition of the scorecard ranked Dominion Energy as 50$^{th}$ out of 52 utilities, earning just 14% of the available "points" in the analysis. Only Florida Power & Light (13%) and Alabama Power (10%) were ranked worse. Industry leaders, in contrast, earned 92% of available points (Eversource Massachusetts and National Grid Massachusetts). The Department of Mines, Minerals and Energy, on its website, retains a wealth of useful reports on energy efficiency and strategies for improving the Commonwealth's progress towards efficiency targets.

[14] Va. Code § 56-585.1(A)(5)(c)
[15] Maggie Molina, *Renewables Are Getting Cheaper But Energy Efficiency, On Average, Still Costs Utilities Less*, ACEEE (Dec. 18, 2018), https://www.aceee.org/blog/2018/12/renewables-are-getting-cheaper-energy
[16] *See* Direct Testimony of Mark James, Virginia Energy Efficiency Council, *Petition of Va. Elec. & Power Company re: 2019 DSM Update,* PUR-2019-00201 (filed Mar. 20, 2020)
[17] Grace Relf, et al., *2020 Utility Energy Efficiency Scorecard,* American Council for an Energy Efficient Economy (Feb. 2020), https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf

The VCEA enacts significant improvements to the Commonwealth's energy efficiency programs, but still more changes will likely be needed to meet E.O. 43's objectives. These include more aggressive energy savings targets for the 2026 to 2028 period, improvements to the energy efficiency docket like those in H.B. 575, green building standards, and state and local governments better monitoring and managing their energy usage.

## IV. Soft Costs of Clean Energy Development

In an economically efficient marketplace, customers would be able to make energy choices that fairly reflect their preferences—the lowest cost, clean energy source might be expected to dominate. But various impediments—permitting challenges, misinformation about clean energy options, inconsistent taxing regimes, etc.—all can prevent the market from working well. These impediments are known as the "soft costs" of clean energy development, and several bills in the 2020 legislative session sought to mitigate their impact.

### A. Local Taxation

The "soft costs" of development—including the impact of local taxes like the machinery and tools tax—can slow the roll out of renewable energy projects. To address this concern and balance the interests of local governments and renewable energy developers, the General Assembly considered several bills related to local taxation.

H.B. 1131/S.B. 762 fashions a compromise between local governments' reliance on property tax revenue and controlling costs for renewable energy developers. The bill authorizes localities to assess a revenue share on solar projects at a rate of up to $1,400/megawatt. In exchange, the project would be fully exempt from local taxation. If a locality does not adopt a revenue share, solar projects are still 80% exempt from local taxation. These exemptions only apply to projects for which the permitting application is filed before July 2030.

The revenue share arrangement does not apply to projects that qualify for net metering under Va. Code §§ 56-594, 56-594.01, or 56-594.2, that have a capacity of less than 20 megawatts and for which the interconnection request was filed before 2019, and that have a capacity of less than 5 megawatts. The bill prohibits localities from retroactively imposing a revenue share though it does not preclude voluntary agreements that waive the machinery and tools tax for existing renewable generation in exchange for a share of the project's revenue.

H.B. 1434/S.B. 763 limits the property tax exemption for solar facilities under Va. Code § 58.1-3660, but extends the exemption's sunset. The current exemption has five tiers based on the size and vintage of solar energy systems. Two categories—systems between 5 and 150 megawatts interconnected in 2019 or later and systems over 20 megawatts interconnected between January 2015 and June 2018 or over 20 megawatts and under 150 megawatts interconnected after June 2018 and came in service after 2016—have 80 percent of their value exempted from property taxation under current law. The bill reduces the exemption for projects in these categories that are interconnected after 2018. The exemption is 80% for the first five years, 70% for the next five years, and 60% thereafter. In exchange, the exemption's sunset is extended from 2024 to 2030. The reduced exemption does not apply to solar projects subject to a revenue share.

H.B. 1327 allows localities to tax electricity utilities' wind turbines for which an interconnection request was filed before July 1, 2020 at a rate that exceeds the real estate rate by up to $0.20 per $100 of assessed value. Under current law, localities may tax wind turbines at a rate that exceeds the real estate rate but does not exceed the general personal property rate in the locality. Taxation of all other wind turbines is governed by the current restrictions.

Finally, S.B. 1039 makes the property tax exemption for solar energy and recycling equipment retroactive to the date of installation if the taxpayer obtains certification within one year of installation. Qualifying taxpayers are entitled to reimbursement if they have already paid taxes before certification.

## B. Local Zoning

Another "soft cost" of renewable energy development is local zoning and land use ordinance restrictions, which can significantly delay renewable energy projects. Legislation that reduces these "soft costs" would help to facilitate and speed up the deployment of new renewable energy projects. A number of bills this session sought to reduce the burden of land use and zoning restrictions. H.B. 655/S.B. 870 allows localities to grant zoning exemptions to solar projects. The exemption may include conditions such as dedication of real property or cash payments for public improvements. At the same time, H.B. 656/S.B. 875 allows localities to incorporate "generally accepted national environmental protection and product safety standards" in their zoning ordinances such as "the National Sanitation Foundation/American National Standards Institute No. 457, International Electrotechnical Commission No. 61215-2, Institute of Electrical and Electronics Engineers Standard 1547, and Underwriters Laboratories No. 61730-2."

H.B. 657 allows a locality to waive the requirement that solar facilities be reviewed for accord with its comprehensive zoning plan. An earlier version of the bill automatically waived review for facilities under 150 megawatts. The current law only exempts from review solar facilities that are eligible for net metering or that are located in an area zoned to allow solar facilities by right.[18]

H.B. 414/S.B. 504 limits communities' ability to impose restrictive covenants on solar installations. It creates a presumption that restrictions that increase the installation's price by more than 5 percent or decrease the installation's production by more than 10 percent below that of the initial proposal are unreasonable. The installer bears the burden of proving these criteria are met.

H.B. 1675 requires developers to meet with local officials to discuss a siting agreement for any solar facility in an IRS designated opportunity zone other than projects that are eligible for net metering or are under 5 megawatts. If the parties come to an agreement, the project is deemed in compliance with the locality's comprehensive zoning plan. If they fail to reach an agreement, this may be used as a factor in the decisions made at other points in the land use approval process.

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[18] *See* Va. Code § 15.2-2232(H)

### C. Renewable Energy Financing

Continuing the discussion on the "soft costs" of renewable energy procurement, it is critical to address financing, especially for smaller, non-utility projects, which do not have the same access to capital (from Wall Street or captive ratepayers) that investor-owned utilities enjoy. A couple bills in the 2020 Legislative Session sought to respond to this inequity.

- H.B. 408 extends the Green Job Creation Tax Credit through 2026. The tax credit is available in the amount of $500 for certain "green jobs" that provide an annual salary over $50,000. Each taxpayer may claim the credit for up to 350 green jobs per year. "Green job" includes employment in the "manufacture and operation of products used to generate electricity and other forms of energy from alternative sources that include hydrogen and fuel cell technology, landfill gas, geothermal heating systems, solar heating systems, hydropower systems, wind systems, and biomass and biofuel systems."

- H.B. 654 authorizes the Department of Mines, Minerals and Energy to sponsor a statewide clean energy financing program akin to the PACE programs developed by localities pursuant to § 15.2-958.3 of the Code of Virginia. This section authorizes localities "to provide loans for the initial acquisition and installation of clean energy, resiliency, or stormwater management improvements" that are repaid through property tax assessments.

## V. Distributed Generation

Generally, these bills promote the installation of small wind and solar projects by non-utility entities such as individuals, businesses, and government actors. Because distributed generation is a broad concept, this category naturally includes a variety of disparate proposals. Some of the common themes are allowing renewable energy sources on government property to sell electricity back to their utility, expanding eligibility for net-metering, and authorizing power purchase agreements so that electricity customers may purchase electricity from third-parties. While promoting distributed generation is not necessary as a matter of law in order to meet the E.O. 43 targets, it can undoubtedly help to lower costs. Many distributed generation projects (*e.g.,* non-utility generation projects) help to put new resources onto the grid without requiring ratepayers to absorb the capital costs or provide an expensive return on equity that any utility-sponsored generation project would carry.

The most comprehensive piece of distributed generation legislation is H.B. 572, which contains four main proposals. First, it creates a multi-family solar program. Second, the bill raises the caps on net-metering and relaxes the co-location requirement for individual projects between the power source and the site of consumption (*i.e.,* they do not have to be adjacent to each other). Thus, the bill allows qualifying localities to install wind or solar facilities of up to 5 megawatts and credit the electricity produced against electricity consumption at other buildings or facilities including those of the locality's public school system, regardless of whether they are contiguous with the generation site. Fourth, the bill expands the pilot program for power purchase agreements. H.B. 1647 is largely similar to H.B. 572.

The other bills in this space are more targeted at promoting specific kinds of distributed generation projects. For example, H.B. 1634/S.B. 629 creates a shared solar program similar to the multi-family solar program of H.B. 572. Public universities, which necessarily play a role as thought leaders for the Commonwealth, also have an important role to play on distributed generation. Thus, S.B. 271 allows public universities to enter into public-private partnerships to install renewable energy sources on public property at no cost in exchange for worker training programs sponsored by the private entity.

H.B. 868 allows consumers to make a power purchase agreement with any licensed supplier[19] for 100% renewable energy, repealing a statutory restriction that required a customer to purchase only from their utility if the utility was approved to offer a 100% renewable tariff at the time of the agreement.[20] Oddly, the bill places an identical new restriction on electric cooperative customers. Customers that choose to purchase 100% renewable energy from a provider other than their incumbent utility are still subject to a 5-year lockout from returning to their incumbent utility.[21] As other providers enter this sector of the market, the General Assembly may consider further deregulation of Virginia's electricity markets.[22]

A few distributed generation bills merit mention at greater length. Again, these bills are not required to achieve the E.O. 43 targets, but may be helpful. They are:

- H.B. 572/S.B. 710, which adds promoting distributed renewable energy to the Commonwealth Energy Policy, enacts new programs and modifies existing programs to this end. First, the bill authorizes the creation of multi-family shared solar program, which allows customers to pool their resources to invest in a solar facility of up to 3 MW at a single location or 5 MW at contiguous locations owned by the same entity. Customers receive a bill credit in proportion to their subscription to the project for 25 years. The credit rate is set at "the effective retail rate of the customer's rate class, which shall be inclusive of all supply charges, delivery charges, demand charges, fixed charges, and any applicable riders or other charges to the customer." The State Corporation Commission is charged with setting uniform fees for interconnection and other protections for participating customers. There is no cap on the program's size. H.B. 572 also prohibits standby charges for net-metering customers except for Dominion residential and agricultural customers generating over 15 kilowatts.

- H.B. 1647, which adopts many of the same distributed generation provisions as H.B. 572 with small modifications. It amends the Commonwealth Energy Policy under identical terms to H.B. 572. It also adopts largely the same changes to net-metering though it offers less protection against standby fees. H.B. 1647 does not allow qualifying localities to net-

[19] *See* Va. Code § 56-587 (providing statutory licensing requirements); 20 VAC § 5-312-040 (outlining the State Corporation Commission's licensing application process).

[20] The State Corporation Commission considers three criteria in the approval of a 100% renewable tariff. The tariff should (1) "hold non-participating customers substantially harmless"; (2) "supply the customer's full load requirements with electric energy provided 100 percent from 'renewable energy' as defined by statute"; and (3) "be reasonable for purposes of the renewable energy product that is being supplied." Order Approving Tariff, *Application of Appalachian Power Company re: approval of a 100% renewable energy rider*, PUR-2017-00179, at 5 (Jan. 7, 2019)

[21] *See* Va. Code § 56-577(3)(c)

[22] *See* H.B. 1677/S.B. 842 (continued to 2021 Session)

meter. The bill also repeals the power purchase agreement pilot program and codifies a similar program as a new subsection of the net-metering code section. Renewable generation facilities of at least 50 kilowatts are eligible provided they meet the following three requirements: (1) the seller provides renewable energy; (2) the renewable energy is generated on the customer's premises; and (3) the agreement only serves one customer unless the customers are income-qualifying customers. There is an aggregate cap of 40 megawatts for Appalachian Power and 500 megawatts for Dominion Energy. Power purchase agreements count against the system-wide net-metering cap of 6 percent. Under the new legislation, the Commission shall "liberally construe" the right to contract to owner or operate a generating facility and the right to finance such facility through leases or power purchase agreements. Parties to a power purchase agreement are protected from regulation as public utilities or competitive service providers.

- H.B. 1634/S.B. 629, which allows Dominion to conduct a shared solar program for facilities with a capacity of less than 5 megawatts on a single plot of land that are owned and operated by a subscriber organization of no fewer than 3 subscribers and with 40% of subscriptions are under 25 kilowatts. The bill directs State Corporation Commission to establish the shared solar program through regulations by 2021. The shared solar program is limited to 150 megawatts with 45 megawatts allocated to low-income customers. Once the low-income allocation is fully subscribed, the program increases to 200 megawatts. As part of the program, Dominion may develop a "minimum bill" to "ensure subscribing customers pay a fair share of the costs of providing electric services," such as transmission and other infrastructure, and to "minimize the costs shifted to customers not in a shared solar program." Low-income participants are exempt from this charge.

- S.B. 271, which allows public colleges and universities to enter into partnerships with private entities and permits the private entity to use the property of the public institution to generate solar or wind power at no cost. Any profits earned by the public institution through a partnership "shall be used to further research, expand clean energy education programs, or lower student tuition rates."

- H.B. 868/S.B. 376, which allows individual customers to purchase 100% renewable energy from any licensed supplier, although the bill is not effective unless reenacted in the 2021 Session.

- H.B. 1133 would make it easier for the State Corporation Commission to approve the construction or purchase of solar or wind facilities (of up 200 MW) on "previously developed project sites" by deeming such facilities in the public interest. The bill defines "previously developed project sites" as property "previously disturbed or developed for non-single-family residential, non-agricultural, or non-silvicultural use." This includes, *inter alia*, retail, commercial, or industrial developments, brownfields, mines, quarries, parking lots or structures, and landfills.

## VI. Environmental Justice and Transition to Clean Energy

### A. Legislation

Achieving a 100% clean-energy grid by 2050 is obviously a task that will have indirect impacts across the economy. Accordingly, a number of bills sought to either *secure* or *smooth* the transition to zero-carbon electricity.

H.B. 706/S.B. 795 was aimed to make sure that federal energy policy does not undermine the Commonwealth's goals. Accordingly, it helps secure Virginia's progress by amending § 28.2-1208 of the Code of Virginia to impose a moratorium on permitting of new offshore drilling: "Neither the Commission nor the Department of Mines, Minerals and Energy shall grant any lease, easement, or permit allowing on the beds of any waters of the Commonwealth any infrastructure for conveying oil or gas associated with an offshore oil or gas lease in the Atlantic Ocean. For purposes of this section, the term 'infrastructure' includes pipelines, gathering systems, processing facilities, storage facilities, and tankers." The bill also eliminates references to offshore drilling in Va. Code § 67-300 and repeals § 67-301 which concerns royalties from offshore drilling. Similarly, S.B. 106 prohibits fracking in a ground water management area as declared before 2020 pursuant to the Ground Water Management Act of 1992 (Va. Code § 62.1-254 *et seq.*).[23]

Under the category of bills that smooth out the transition is H.B. 528, which directs the State Corporation Commission to determine the amortization period over which Appalachian Power and Dominion can recover costs for the early retirement of any electricity generating facility, particularly coal and natural gas facilities.

H.B. 167 is an effort to *both* secure and smooth the transition to clean energy by requiring a utility seeking to recover fuel costs under a new natural gas capacity contract that has a term of over 10 years and that procures more than 250,000 dekatherms per day to prove to the State Corporation Commission by a preponderance of the evidence that the utility has:

> (i) determined that the utility cannot meet its service obligations, giving due regard, in the Commission's sole discretion, to reliability of service and the need to maintain reliable sources of supply, without an additional fuel resource;
> (ii) reasonably identified and determined the date and amount of the new fuel resource it needs;
> (iii) objectively studied available alternative fuel resource options, as verified by the Commission, including options other than a new natural gas capacity contract or contracts to meet the identified and determined need; and
> (iv) determined that the natural gas capacity contract or contracts are the lowest-cost available option, taking into consideration fixed and variable costs and a reasonable projection of utilization.

H.B. 573 requires utilities to select at least one facility in a low-income community for every facility outside low-income communities for participation in community solar development pilot

[23] There are only two groundwater management areas in Virginia. One comprises the area East of Interstate 95, and the other comprises the two counties on the Delmarva Peninsula. *See* 9 VAC § 25-600-020.

program pursuant to Va. Code § 56-585.1:3. This bill is especially important, as low-income and other disadvantaged communities may be especially impacted by the transition to carbon-free energy. In Virginia, low-income households spend a greater proportion of their income on energy,[24] so they are more impacted by rate changes. In addition, clean energy may be slower to reach disadvantaged communities, preventing them from sharing equally in its benefits. The General Assembly has begun to address these issues through several legislative efforts, in addition to H.B. 573.

While environmental justice legislation is not strictly necessary to achieving the goals of E.O. 43, Virginia should consider ways in which environmental justice initiatives can help smooth the transition to zero carbon and ensure that no community is left behind. To that end, H.B. 1042/SB 883 creates a 27 member Virginia Council on Environmental Justice charged with advising the Governor and General Assembly on environmental justice issues and considerations.

H.B. 704/SB 406 further declares "[i]t is the policy of the Commonwealth to promote environmental justice and ensure that it is carried out throughout the Commonwealth. To further this policy, each state agency shall examine any proposed regulation or policy involving state action or funds for its impact on environmental justice." In addition, each state agency must develop an environmental justice policy.

### B. Coordination of Environmental Justice Programs

Other legislation, in particular the VCEA and some distributed generation bills, also contain important environmental justice provisions, but they have differing definitions of which populations may be eligible. The provisions of the VCEA concerning low-income and disadvantaged communities use the following five definitions:

- *Community in which a majority of the population are people of color* means a U.S. Census tract where more than 50 percent of the population comprises individuals who identify as belonging to one or more of the following groups: Black, African American, Asian, Pacific Islander, Native American, other non-white race, mixed race, Hispanic, Latino, or linguistically isolated.
- *Historically economically disadvantaged community* means (i) a community in which a majority of the population are people of color or (ii) a low-income geographic area.
- *Low-income geographic area* means any locality, or community within a locality, that has a median household income that is not greater than 80 percent of the local median household income, or any area in the Commonwealth designated as a qualified opportunity zone by the U.S. Secretary of the Treasury, via his delegation of authority to the Internal Revenue Service.
- *Low-income utility customer* means any person or household whose income is no more than 80 percent of the median income of the locality in which the customer

[24] Fisher, Sheehan & Colton, *Home Energy Affordability Gap* (2019), http://www.homeenergyaffordabilitygap.com/

resides. The median income of the locality is determined by the U.S. Department of Housing and Urban Development.

- *Percentage of Income Payment Program (PIPP) eligible utility customer* means any person or household participating in any of the following public assistance programs: the Supplemental Nutrition Assistance Program, Temporary Assistance for Needy Families, Special Supplemental Nutrition Program for Women, Infants and Children, Virginia Low Income Home Energy Assistance Program, federal Low Income Home Energy Assistance Program, state plan for medical assistance, Medicaid, Housing Choice Voucher Program, or Family Access to Medical Insurance Security Plan.

As part of the VCEA's renewable portfolio standard, Dominion must meet one percent of its requirements from small projects, of which 0.25 percent must come from "low-income qualifying projects"—defined as "project[s] that provide[] a minimum of 50 percent of the[ir] respective electric output to low-income utility customers—"to the extent that [such] projects are available." Revenue from deficiency payments is earmarked for job training (50%) and renewable energy programs (30%) in "historically disadvantaged communities." In addition, "low-income utility customers" are allocated a portion of the net-metering systemwide cap. And, of course, the State Corporation Commission will design the Percentage of Income Payment Program around the statutory definition of PIPP-eligible utility customers. Finally, the VCEA requires DMME to determine every three years, beginning in 2022, whether the VCEA imposes a "disproportionate burden" on historically disadvantaged communities.

The VCEA also directs utilities to consult with the Clean Energy Advisory Board regarding "how best to inform low-income customers of opportunities to lower electric bills through access to solar energy." Such opportunities will expand considerably thanks to legislation liberalizing net-metering and creating community solar programs that operate on a subscription model, making it easier for individuals with modest incomes to participate by allowing smaller investments. As currently written, these programs apply to slightly different low-income populations.

The VCEA and H.B. 572 liberalize net metering on identical terms. Specifically, they allocate one percentage point of the six-percent systemwide cap to "low-income utility customers." By contrast, H.B. 1647 makes the same allocation to "income-qualifying" customers.[25] In addition, H.B. 1647 authorizes certain power purchase agreement that would qualify for net-metering if the customer owned the renewable energy facility. The single customer requirement for these power purchasing agreements is relaxed for income-qualifying customers, allowing such customers aggregate their loads on the same premises.

[25] The bill defines a "income-qualifying customer" as "an individual or household with an income of not more than 60 percent of the state median income or area median income, whichever is greater, based on U.S. Department of Housing and Urban Development guidelines." An individual may also qualify if "eligible to participate in any of the following programs: the Home Energy Assistance Program; the state plan for medical assistance; the Supplemental Nutrition Assistance Programs; the Special Supplemental Nutrition Programs for Women, Infants and Children; the Housing Choice Voucher Program; the Family Access to Medical Insurance Security Plan; or Temporary Assistance for Needy Families."

At the moment, Virginia does not allow solar projects to follow a subscription model in which multiple customers share in the ownership and output of a solar facility. H.B. 572 and H.B. 1634 are drafted to change that. Each authorizes a new community solar program, but on slightly different terms. H.B. 572 establishes a multi-family solar program. A qualifying "shared solar facility" meets five conditions. It is a facility that:

(1) Generates electricity by means of a solar photovoltaic device with a nameplate capacity rating that does not exceed 3,000 kW alternating current at any single location or that does not exceed 5,000 kW alternating current at contiguous locations owned by the same entity or affiliated entities;
(2) Is operated pursuant to a program whereby at least three subscribers receive a bill credit for the electricity generated from the facility in proportion to the size of their subscription;
(3) Is located in the service territory of an investor-owned utility;
(4) Is connected to the electric distribution grid serving the Commonwealth; and
(5) Is located on a parcel of land on the premises of the multi-family utility customer or adjacent thereto.[26]

H.B. 1634 establishes a similar shared solar program though with additional requirements for small subscriptions. A qualifying "shared solar facility" meets six conditions. It is a facility that:

(1) Generates electricity by means of a solar photovoltaic device with a nameplate capacity rating that does not exceed 5,000 kilowatts of alternating current;
(2) Is located in the service territory of an investor-owned electric utility;
(3) Is connected to the electric distribution grid serving the Commonwealth;
(4) Has at least three subscribers;
(5) Has at least 40 percent of its capacity subscribed by customers with subscriptions of 25 kilowatts or less; and
(6) Is located on a single parcel of land.

Unlike H.B. 572, H.B. 1634's shared solar program contains an aggregate cap of 150 megawatts of which 45 megawatts is reserved for low-income customers. The bill defines a "low-income customer" as "an individual or household with an income of not more than 80 percent of the median income of the locality in which the customer resides" as "determined by the U.S. Department of Housing and Urban Development."[27] Once the low-income allocation is fully subscribed, the program may expand to 200 megawatts of aggregate capacity. Compliance with the low-income customer allocation may be measured either by project capacity or project savings.

[26] The definition of "investor owned utility" in the section authorizing the program excludes Appalachian Power.

[27] The bill also defines "low-income service organization" and "low-income shared solar facility." However, it does not employ these terms other than to require that the State Corporation Commission's stakeholder process for the developing the program include both low-income customers and low-income service organizations.

A couple other pieces of legislation further address how low-income customers may be impacted by energy transitions. H.B. 981 allocates at least quarter of expenditures on flood preparedness from the sale of allowances for Virginia's RGGI trading program (at least 11.25% of the total revenue) to projects in "low-income geographic area[s]." The term is given the same definition as in the VCEA. Half of the revenue is dedicated to "low income energy efficiency programs," but the bill does not define this term though bill explicitly states that energy efficiency programs that target public housing as it is defined in Va. Code § 36-141[28] are eligible. Finally, H.B. 573 requires "community solar" pilot programs established pursuant to Va. Code. § 56-585.1:3 to select one or more facilities in a low-income community for each facility selected outside low-income communities. The facility, or facilities, must have a cost at least as high as the facility outside low-income communities. The bill defines a "low-income community" as "a census tract within the Commonwealth designated by the U.S. Department of Housing and Urban Development in 2019 or any year thereafter as a qualified census tract for purposes of the Low-Income Housing Tax Credit pursuant to § 42 of the Internal Revenue Code."

## VII. Studies, Reports, Task Forces, and the Commonwealth Energy Policy

Many bills from the 2020 legislative session set Virginia on the path toward meeting the targets of E.O. 43. At the same time, it is undeniable that the path will have to be modified as economic, scientific, and technological conditions change over the years. To prepare for new legislation that may be necessary in the coming years, many legislators introduced bills aimed at investigating the next steps and understanding the potential difficulties that might be encountered along the way. While such studies might not be strictly necessary to meeting the E.O. 43 targets, they are certainly helpful. Gathering this information now will allow policymakers to better develop new programs and refine existing ones in the future.

With that in mind, S.B. 1183 is noteworthy as it directs the State Corporation Commission to convene a task force to "evaluate and analyze the potential for bulk energy storage resources to help integrate renewable energy into the electrical grid, reduce costs for the electricity system, allow customers to deploy storage technologies to reduce their energy costs, and allow customers to participate in electricity markets for energy, capacity, and ancillary services." The task force will "assess the potential costs and benefits, including impacts to the transmission and distribution systems, of such energy storage resources" and "assess how electric utilities, competitive service providers, customers, and other third parties are able to deploy energy storage resources in the bulk market, in the utility system, and in behind-the-meter applications."

[28] Va. Code § 36-141 states "[h]ousing development or housing project means any work or undertaking, whether new construction or rehabilitation, which is designed and financed pursuant to the provisions of this chapter for the primary purpose of providing affordable sanitary, decent and safe dwelling accommodations for persons and families of low or moderate income in need of housing; such work or undertaking may include any buildings, land, equipment, facilities, or other real or personal properties which are necessary, convenient, or desirable appurtenances, including but not limited to streets, sewers, utilities, parks, site preparation, landscaping, and such offices, and other nonhousing facilities incidental to such development or project such as administrative, community, health, educational and recreational facilities as the Department of Housing and Community Development determines to be necessary. Low and moderate income shall be defined in the program guidelines developed by the Department of Housing and Community Development." (internal quotation marks omitted)

H.B. 889 is another bill aimed at leveraging the expertise of the State Corporation Commission. It directs the Commission to conduct a retail competition pilot program in which customers may aggregate their loads. The pilot program is limited to 200 megawatts of total load.

Virginia has taken a remarkably slow and cautious path toward developing its offshore wind resources. A small, two-turbine test project, totaling just 12-megawatts, remains under construction but not yet in service after years of delay.[29] By way of comparison, European Union countries installed 3600 megawatts of offshore wind capacity in calendar year 2019, and another 2,600 megawatts in 2018. In total, E.U. countries maintain approximately 22,000-megawatts of offshore wind capacity in service.[30]

To help accelerate the process of offshore wind development in Virginia, H.B. 234 creates a Division of Offshore Wind within the Virginia Department of Mines, Minerals and Energy. The division is tasked with "[i]dentifying specific measures that will facilitate the establishment of the Hampton Roads region as a wind industry hub for offshore wind generation projects," coordinating state agencies actions regarding offshore wind, identifying regulatory barriers to offshore wind, and providing support for the Virginia Offshore Wind Development Authority. The division must produce an annual report on the state of offshore wind for the Governor and General Assembly.

Other study-related bills include H.B. 1707, which adds two members to the Virginia Clean Energy Advisory Board, "an expert with experience developing low-income or moderate-income incentive and loan programs for distributed renewable energy resources" and "an attorney who is licensed to practice in the Commonwealth and maintains a legal practice dedicated to rural development, rural electrification, and energy policy." The bill also repeals the Board's 2022 sunset and directs DMME to consult with the board in developing a renewable energy grant program. However, the program did not receive funding in the budget for 2020.

A number of bills sought to integrate the objectives of E.O. 43 into the Commonwealth Energy Policy. Although the Commonwealth Energy Policy is not binding, it remains an important long-term planning document. Some of the bills related to the Commonwealth Energy Policy go far beyond E.O. 43 in terms of moving Virginia away from a carbon-based economy. For example, S.B. 94/H.B. 714 contemplates decarbonization of the entire economy in addition to the electricity sector.

S.B. 94/H.B.714 strengthens the energy objectives of Va. Code § 67-100 regarding energy efficiency and distributed generation while incorporating targets similar to those of E.O 43 into the Commonwealth Energy Policy and Virginia Energy Plan. These revisions reflect the demands of decarbonization and the transition to clean energy, while continuing to preserve a role for certain fossil fuels, like natural gas. As revised, the Commonwealth Energy Policy declares that is the policy of Virginia to:

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[29] *See* Dominion Energy*, Coastal Offshore Wind*, https://www.dominionenergy.com/company/making-energy/renewable-generation/wind/coastal-virginia-offshore-wind (last visited March 30, 2020)

[30] Anmar Frangoul, *Offshore wind installations in European waters hit a record level last year,* CNBC.com (Feb. 6, 2020), https://www.cnbc.com/2020/02/06/offshore-wind-installations-in-europe-hit-a-record-level-last-year.html.

- Ensure the adequate supply of natural gas necessary to ensure the reliability of the electricity supply and the needs of businesses during the transition to renewable energy;
- Establish greenhouse gas emissions reduction standards across all sectors of Virginia's economy that target net-zero emissions carbon by 2045;
- Enact mandatory clean energy standards and overall strategies for reaching net-zero carbon in the electric power sector by 2040;
- Equitably incorporate requirements for technical, policy, and economic analyses and assessments that recognize the unique attributes of different energy resources and delivery systems to identify pathways to net-zero carbon that maximize Virginia's energy reliability and resilience, economic development, and jobs; and
- Minimize the negative impacts of climate change and the energy transition on economically disadvantaged or minority communities and prioritize investment in these areas.

The bill also requires the Virginia Energy Plan to "identif[y] actions…to achieve, no later than 2045, a net-zero carbon energy economy for all sectors, including electricity, transportation, building, and industrial sectors." Other changes require the Plan to include projections of non-renewable, carbon-free energy consumption, "an assessment of state and local impediments to expanded use of distributed resources and recommendations to reduce or eliminate these impediments," and an inventory of greenhouse gas emission for the previous four years. Beginning in 2024, the regular interim updates to the Plan must also contain projections of what greenhouse gas emissions would be were the Plan implemented.

Finally, S.B. 549/H.B. 1303 directs DMME, in consultation with the Secretary of Commerce, the Secretary of Education, the Virginia Nuclear Energy Consortium Authority, and the Virginia Economic Development Partnership Authority, to develop a strategic plan by October 1, 2020 for the role of nuclear energy in the transition to carbon-free energy. The plan will be updated every four years.

Other bills also focus on the role that nuclear energy might play in the transition away from a carbon-based economy. S.B. 828 defines carbon-free energy and clean energy identically to include "electric energy generated from a source that does not emit carbon dioxide into the atmosphere during the process of generating the electric energy, including electric energy generated by the conversion of sunlight, wind, falling water, wave motion, tides, geothermal or nuclear energy." Meanwhile, S.B. 817 declares that nuclear energy is considered a clean energy source for the purposes of the Commonwealth Energy Policy and any clean energy or carbon-free energy initiative.

## VIII. Continued to 2021 Session

A number of bills from the 2020 Legislative Session that could impact the objectives of E.O. 43 were continued to the 2021 Legislative Session. These bills cover a range of subjects, from net-metering eligibility (addressed in H.B. 1067) to reports on the progress of solar installations and the role of conservation easements (addressed in H.B. 1171).

Other bills look at renewable energy financing. H.B. 947 would have expanded "green development zones," while H.B. 1061 would have extended the C-PACE ("Commercial Property Assessed Clean Energy") enabling legislation to dwellings with fewer than five units. This change would allow such properties to obtain a voluntary special assessment lien against their property to finance renewable energy installations if their locality offers such a program.

H.B. 1677/S.B. 842, would go in a dramatically different direction than the managed, targeted approach of the Virginia Clean Energy Act. Instead of using well-established regulatory tools to mandate a clean-energy transition, H.B. 1677/S.B. 842 seek to deregulate electricity markets and allow retail customers to purchase electricity from a provider of their choice.

Finally, for the purposes of meeting the E.O. 43 targets, the most directly applicable bill might be H.B. 547, which would create a new council to oversee the transition from fossil fuels to zero-carbon energy envisioned by E.O. 43. H.B. 547 would create a 30-member Virginia Energy and Economy Transition Council within the executive branch to manage the transition from fossil fuel energy to renewable energy by 2050. The council would contain 17 citizen members and 13 ex officio members of the General Assembly.

## IX. Conclusion

As the above summary makes clear, the 2020 Virginia General Assembly took a comprehensive approach to decarbonization, passing a Virginia Clean Economy Act and other legislative initiatives that: (1) establish a binding the renewable portfolio standard; (2) leverage market forces to reduce carbon pollution by linking Virginia's efforts to a broader emissions trading program, such as the Regional Greenhouse Gas Initiatives; and (3) prioritize efforts to reduce the need for fossil-fuel generation through mandatory, low-cost energy efficiency targets. All three of these approaches will remain essential as Virginia moves towards Executive Order 43's short-term goal on renewables (within the next ten years) and longer-term goal on carbon-free electricity. Of course, it is unlikely that Virginia's utility and environmental laws will (or should) remain static over the next thirty years, as the 2050 target approaches. Thus, it will be important to preserve the pillars of binding action – with strong measures to ensure accountability and enforceability – as amendments to the VCEA are brought forward.

CHAPTER 3:
REGULATION OF UTILITIES BY THE STATE CORPORATION COMMISSION

The State Corporation Commission is the primary body with regulatory authority over energy generation, electricity pricing, and electric utility service in Virginia.[1] The Commission derives its authority directly from the Constitution of Virginia, but administers that authority pursuant to directives from the Virginia General Assembly.[2] The Commission's primary legislative authority to regulate energy markets derives from Title 56 of the Code of Virginia.[3] From this legislative mandate to regulate public industries, what has resulted is an arrangement referred to as a "regulatory compact" between Commission and electric utilities.[4] This compact allows for the Commission to govern rates and approve (or reject) major capital investments by the utility. In exchange for being regulated, utilities are granted a state-protected monopoly to operate "without any competition to their geographic service territories."[5]

After a brief attempt of deregulation of the electricity market in 1999, the Virginia Assembly passed a Re-Regulation Act in 2007.[6] The Re-Regulation Act did not, however, return Virginia utilities to the *status quo ante* 1999. Instead, the new law established new procedures for reviewing each utility's rates and earnings, provided opportunities for investor-owned utilities to earn significant basis-point "adders" to increase rates, allowed utilities to retain a portion of over-earnings, and made it difficult for the Commission to reduce electricity rates absent several, consecutive years of over-earnings. The 2007 Act also established a flawed but voluntary Renewable Portfolio Standard ("RPS"), retail options for utility customers to leave an incumbent utility and purchase renewable energy from competitive service providers ("CSPs"), and granted utility customers the right to participate in net-metering programs.[7] The structure was substantially revised in 2018 as part of the Grid Transformation and Security Act, and again in 2020 as part of the Virginia Clean Economy Act.[8] Today, Virginia has a semi-regulated electricity market. That is, a vertical utility model remains in place under which customers are required to buy from their incumbent utility, subject to a few exceptions allowing for competition.

## I. Pre-Existing Statutory Barriers to Renewable Energy Development

Chapter 2 of this Report provides information on important changes to Virginia law, with a focus on the Virginia Clean Economy Act. ("VCEA"). At the same time, it is necessary to understand

[1] State Corporation Commission, *About the Agency*, https://www.virginia.gov/agencies/state-corporation-commission/ (last visited Feb. 29, 2020)
[2] *See Old Dominion Comm. for Fair Util. Rates v. State Corp. Comm'n* 803 S.E.2d 758 (Va. 2017); Va. Const. Art. IX, § 2
[3] Va. Code § 56-10
[4] GreeneHurlocker, PLC, *Guide to Electric Utility Regulation in Virginia* 2 (2nd ed. 2018)
[5] *Id.*
[6] 2007 Va. Acts of Assembly, Ch. 888 (codified as amended at Va. Code. §§ 56-576 to -594); 2007 Va. Acts of Assembly, Ch. 933 (codified as amended at Va. Code. §§ 56-576 to -594)
[7] *See id.*
[8] *See* 2018 Va. Acts of Assembly, Ch. 296, https://lis.virginia.gov/cgi-bin/legp604.exe?181+ful+CHAP0296; House Bill 1526 (Enrolled), 2020 Virginia Legislative Session, https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+HB1526ER.

the state of the law prior to enactment of the VCEA, as many aspects of Virginia regulatory law inhibited renewable energy development. These barriers include: (1) carbon-emitting generation included in the definition of "renewable energy;" and (2) restrictions on retail competition as a means of promoting renewable energy.

### A. Carbon-Emitting Generation Included in the Definition of Renewable Energy

Va. Code § 56-576 defines "Renewable Energy" to be:

> "[E]nergy derived from sunlight, wind, falling water, biomass, sustainable or otherwise, (the definitions of which shall be liberally construed), energy from waste, landfill gas, municipal solid waste, wave motion, tides, and geothermal power, and does not include energy derived from coal, oil, natural gas, or nuclear power. Renewable energy shall also include the proportion of the thermal or electric energy from a facility that results from the co-firing of biomass."

The inclusion of "energy from a facility that results from the co-firing of biomass" remains problematic, as it includes as "renewable" energy generated at coal-fired power plants, such as Dominion Energy's Virginia City Hybrid Energy Center in the Coalfields region of the Commonwealth. That 585 megawatt facility uses coal, waste coal, and waste wood biomass to generate electric power.[9] As a proportion of the energy comes from the co-firing of biomass, a pro-rata share of the energy from Virginity City Hybrid Energy Center can be legally classified as renewable energy under § 56-576, complicating efforts to develop a zero-carbon electricity grid in Virginia. The statutory definition also risks allowing utilities and independent power providers to retrofit existing, coal-fired facilities to use biomass for a portion of their fuel, rather than promoting the development of new, zero-carbon renewable energy projects in the Commonwealth.

### B. Restrictions on Retail Competition as a Means of Promoting Renewable Energy

Most retail customers in Virginia receive their electricity from an investor-owned electric utility company, primarily Dominion Energy or Appalachian Power. Under regulation from the Virginia State Corporation Commission, investor-owned utilities manage: (1) the generation or acquisition of energy; (2) the transmission of electric from power stations to communities; and (3) the distribution and sale of electricity to retail customers. This regulatory structure means that the Commonwealth largely relies on these utilities to develop the renewable energy and zero carbon resources needed to achieve targets under the Virginia Clean Economy Act. Independent power providers have limited—and tightly restricted—opportunities to compete. Under Va. Code § 56-577(A)(5), a competitive service provider can provide customers with electricity service "provided 100 percent from renewable energy" so long as the incumbent utility does not offer an approved 100% renewable energy tariff. Alternatively, under Va. Code § 56-589, municipalities can elect community choice aggregation as an alternative to service from the incumbent, investor-owned utility. If independent power providers are going to play a larger role in the development of renewable energy under either of these mechanisms, changes to the existing statutory regime may be necessary.

[9] Dominion Energy, *Virginia City Hybrid Energy Center*, https://www.dominionenergy.com/company/making-energy/coal-and-oil/virginia-city-hybrid-energy-center (last visited Apr. 25, 2020)

First, pursuant to Va. Code § 56-577(A)(5), the two largest "incumbent utilities" in Virginia, Appalachian Power and Dominion Energy, have filed petitions for approval of 100 percent renewable energy tariffs. The Appalachian Power tariff has been approved.[10] Dominion Energy's proposal for a similar rider has been reviewed by a Hearing Examiner, who recommended approval subject to certain conditions.[11] A final order from the Commission in the Dominion Energy docket had not been issued at the time this report was prepared.

In reviewing and rejecting an earlier proposal from Dominion Energy, the Commission held, "There is no statutory basis for the Commission to disfavor incumbent utility tariffs proposed under [Va. Code. § 560-577(A)(5)] or, similarly, to apply an unwritten heightened standard before approving a proposed 100% renewable energy tariff. Rather, the Commission will evaluate the facts in this proceeding, as it would any tariff request, to reach a finding as to whether the proposed rate schedules are just and reasonable."[12] Applying that standard, the Commission approved Appalachian Power's proposal for a 100% renewable energy tariff, even though the utility did not proffer to build new renewable energy resources to fulfill the tariff.[13] Rather, Appalachian Power designed a tariff that relies primarily on repackaging existing renewable resources that are already on the grid in one offering for interested customers.[14]

Since approval of the tariff bars competitive service providers from offering an alternative project, it may be that approval of the tariff under Va. Code § 56-577(A)(5) might actually slow development of renewable resources in Virginia. Amendments to Va. Code § 56-577(A)(5), for example, might allow competitive service providers to bring on *new* renewable energy resources, or require incumbent utilities to continually update their offerings with new resources as a condition of approval.

A second option for competition comes in the form of community choice aggregation under Va. Code § 56-589. Virginia law allows for the development of a Community Choice Aggregation ("CCA") program, so long as the CCA satisfies certain restrictions identified in the Code. The most relevant provisions leading us to this conclusion are Va. Code §§ 56-577(A)(3) and § 56-589, which support a finding that a CCA can be developed as a matter of right. Opponents of a proposed CCA might argue Va. Code § 56-577(A)(4) and (A)(5) provide various impediments to the development of municipal aggregation, and could argue that subdivision A 4 requires a finding by the State Corporation Commission that a CCA is in the "public interest" and would not adversely affect the incumbent utility or customers who are not part of the CCA. The question about the applicability of subdivisions (A)(4) and (A)(5) is critical to the analysis. Under subdivision (A)(4), the Commission appears to have fairly broad discretion to approve or reject a proposal on public interest grounds. If the subdivisions do not apply—which we think is the

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[10] *See* Final Order, *Application of Appalachian Power Co. for Approval of a 100% Renewable Energy Rider*, PUR-2017-00129 (Jan. 7, 2019)
[11] *See* Hearing Examiner's Report, *Application of Va. Elec. & Power Co. for Approval of a 100% Renewable Energy Tariff, designated Rider TRG*, PUR-2019-00094 (issued April 20, 2020)
[12] Final Order, *Application of Va. Elec. & Power Co. for Approval of 100% Renewable Energy Tariffs*, PUR-2017-00060, at 6 (May 7, 2018)
[13] *See* Final Order, *Application of Appalachian Power Co. for Approval of a 100% Renewable Energy Rider*, PUR-2017-00129 (Jan. 7, 2019)
[14] *Id.*

correct analysis—then the Commission's role is far more limited. To be clear, the Clinic's view is that subdivisions (A)(4) and (A)(5) are inapplicable in the CCA context under Va. Code § 56-589. Community choice aggregation is generally available to municipalities *by right.*

This legal right notwithstanding, there are some important limitations imposed by Va. Code § 56-577(A)(3), and processes under § 56-589, that must be followed before a CCA can or should be established. This report briefly addresses these limitations and processes as well. Va. Code § 56-589(A) articulates three options a municipality might pursue to design a CCA: (1) on behalf of customers within its jurisdiction; (2) on behalf of itself for its governmental buildings and facilities; and (3) on behalf of itself and other municipalities for their governmental buildings and facilities, provided that the several municipalities are "are acting jointly" to negotiate power purchases.

The General Assembly explicitly provided that § 56-589 would be implemented "[s]ubject to the provisions of subdivision A 3 of § 56-577." Subdivision (A)(3), in turn, references that its restrictions are "[s]ubject to the provisions of subdivisions 4 and 5" of the same Code provision. Thus, there is a question as to whether this internal cross-reference has the effect of rolling all of these subdivisions into Va. Code § 56-589, even though § 56-589 makes no reference itself to "subdivisions 4 and 5" of § 56-577. That is, there may be an unresolved question as to whether §§ 56-577(A)(4) and (A)(5) could be "daisy-chained" into the municipal aggregation statute, which would add additional barriers to the development of a CCA program. The Supreme Court of Virginia, however, explicitly rejected this argument, finding that the provisions stand largely alone.[15] "There is no notice requirement for purchases under Section (A)(5), and no language that incorporates the notice provision from (A)(3) into (A)(5)."[16]

Thus, even if a utility attempted to block municipal aggregation by arguing that the restrictions of subdivision (A)(4) are incorporated by reference into the instructions of § 56-589, the Supreme Court is likely to reject the argument, citing its decision in *VEPCO.* The simplest way to read the statute would be to recognize that the General Assembly made an explicit decision to include within the language of Va. Code § 56-589 a specific reference to § 56-577(A)(3), but no reference to subdivisions (A)(4) or (A)(5). Thus, the requirement for a public interest finding in subdivision (A)(4) is not part of the approval process for any community choice aggregation proposal under Va. Code § 56-589.

Notwithstanding the above analysis, if § 56-577(A)(4) were found to apply to municipal aggregation, then a locality would have to petition the State Corporation Commission for permission to aggregate its residents' electricity demands. An approval by the Commission would require a finding that: (1) neither the incumbent utility nor non-aggregated customers will be adversely affected in a manner contrary to the public interest; and (2) approval of such petition is consistent with the public interest.[17] To date, the Commission has decided three customer

[15] *See Va. Elec. and Power Co. ("VEPCO") v. State Corp. Comm'n*, 810 S.E.2d 880, 885 (Va. 2018)
[16] *Id.*
[17] *See* Va. Code § 56-577(A)(4)

aggregation petitions under Va. Code § 56-577(A)(4).[18] In *Petition of Reynolds Group Holdings Inc.*, a small group of affiliated industrial customers successfully petitioned the Commission to aggregate six accounts for a total of 10.12 megawatts in Dominion Energy's service territory.[19] The approval in *Reynolds* was based on a determination that this "first and limited aggregation request [was approved] in order to gain initial, measured experience related to implementing this statutory provision."[20]

By contrast, the Commission denied requests by Wal-Mart Stores to aggregate a larger number of commercial accounts in both Dominion and Appalachian Power service territories.[21] Wal-Mart Stores had sought to aggregate 120 customers in Dominion's service territory for a total 70.52 megawatts of capacity, and 44 customers in Appalachian Power's service territory for 20.57 megawatts.[22] The Commission reasoned that aggregated retail choice under § 56-577(A)(4) was *not* a right of customers, but remained subject to the Commission's discretion in determining what is in the public interest.[23]

Assuming that § 56-577(A)(4) and (A)(5) are inapplicable to CCAs, there are still several requirements that must be met to adhere with subdivision (A)(3). Most obviously, Va. Code § 56-577(A)(3) requires a demand of at least 5 megawatts in the previous calendar year to qualify. To meet this threshold, § 56-589(A) permits a municipality to aggregate the electric load of: (1) the residential, commercial, and industrial retail customers within its boundaries on an opt-in or opt-out basis; (2) its governmental buildings, facilities, and any other governmental operations requiring the consumptions of electric energy; or (3) its governmental buildings, facilities and any other governmental operations requiring the consumption of electric energy with that of additional municipalities or other political subdivisions.

In addition to having to meet a minimum demand threshold, § 56-577(A)(3) requires that a customer *cannot* have had a peak demand exceeding one percent of the incumbent utility's peak load during the previous calendar year unless "such customer had noncoincident peak demand in excess of 90 megawatts in calendar year 2006 or any year thereafter." The noncoincident peak demand is a generally accepted industry term referring to that customer's peak demand during the stated timeframe.

Lastly, and perhaps most importantly, § 56-577(A)(3)(c) requires a five-year written notice period before the customer may return to the incumbent utility for any reason. This requirement may be waived by the Commission by a finding that it would not adversely impact the incumbent utility

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[18] For purposes of this report, the two petitions filed by Wal-Mart Stores were evaluated as a single petition, as they were decided simultaneously and under similar conditions. The third petition filed by Costco (PUR-2018-00088) was not evaluated for this report. The Commission's analysis was similar to its analysis in the Wal-Mart petitions.

[19] *See* Opinion, *Petition of Reynolds Holding Group Inc. For permission to aggregate or combine demands of two or more individual nonresidential retail customers of electric energy*, PUR-2017-00109, at 3 (May 16, 2018)
[20] *Id.* at 4
[21] *See* Final Order, *Petitions of Wal-Mart Stores, LP and Sam's East Inc. For permission to aggregate or combine demands of two or more individual nonresidential retail customers of electric energy*, PUR-2017-00174 and PUR-2017-00173 (Feb. 25, 2019)
[22] *Id.*
[23] *See, e.g., id.*

or its customers, including a consideration of the cumulative impact of previous waivers. The Commission would also be directed to prescribe a stay period to remain with the incumbent utility after returning. These requirements likely only apply at the programmatic level (*e.g.,* to the municipality as a whole and not to individual retail customers within that municipality, who may participate "on an opt-in or opt-out basis" pursuant to Va. Code § 56-589(A)(1)).

Overall, the challenges to aggregation of meters may impose barriers to development of renewable energy resources that may need to be re-evaluated as the Commonwealth moves toward the targets outlined in Executive Order 43, of producing 30% of Virginia's electricity from renewable energy sources by 2030 and 100% from carbon-free sources by 2050.

## II. State Corporation Commission Regulation of Renewable Generation Facilities

The Commission's review of any new generation project is, of course, conducted pursuant to statutes enacted by the General Assembly. Virginia Code §§ 56-580(D) and 56-265.2 outline the basic process, as follows. Virginia Code § 56-580(D) states that:

> "The Commission shall permit the construction and operation of electrical generating facilities in Virginia upon a finding that such generating facility and associated facilities (i) will have no material adverse effect upon reliability of electric service provided by any regulated public utility, (ii) are required by the public convenience and necessity, if a petition for such permit is filed after July 1, 2007, and if they are to be constructed and operated by any regulated utility whose rates are regulated pursuant to § 56-585.1, and (iii) are not otherwise contrary to the public interest."

Section 56-265.2 further provides that a certificate of public convenience and necessity ("CPCN") will only be issued upon a finding that:

> "[S]uch generating facility and associated facilities including transmission lines and equipment (i) will have no material adverse effect upon the rates paid by customers of any regulated public utility in the Commonwealth; (ii) will have no material adverse effect upon reliability of electric service provided by any such regulated public utility; and (iii) are not otherwise contrary to the public interest. In review of its petition for a certificate to construct and operate a generating facility described in this subsection, the Commission shall give consideration to the effect of the facility and associated facilities, including transmission lines and equipment, on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact as provided in § 56-46.1."[24]

The Commission's application of these statutes is guided by its own regulations, which will almost certainly require revisions to account for changes in the Virginia Clean Economy Act. 20 VAC § 5-302-20 covers applications for renewable energy electric generating facilities with a rated capacity over 100 megawatts. Applications filed for renewable generation must include:

[24] Va. Code § 56-265.2(B)

(i) the nature of the proposed facility;
(ii) the applicant's technical and financial fitness to construct;
(iii) operate and maintain the proposed facility;
(iv) the effects of the facility on the environment and economic development;
(v) the effects of the facility upon reliability of electric service provided by any regulated public utility; and
(vi) why construction and operation of the proposed facility is not contrary to the public interest.[25]

Electric utilities in Virginia are subject to additional requirements when proposing a new electricity generation project and must "provide justification of the need for the proposed facility."[26] Notably, electric utilities must provide "economic studies that compare the selected alternative with other options, including… production costing simulation of the applicant's overall generating resources that demonstrate that the selected option is the best alternative" and a "detailed cost estimate for the facility, including project costs of construction, transmission interconnections, fuel supply related infrastructure improvements and project financing."[27]

Nothing in this review process accounts for the need to replace, as quickly as possible, fossil-fuel resources with new renewable generation *before* older, fossil-fuel resources reach the end of their originally anticipated lifecycles. There is no requirement, for example, to consider the Social Cost of Carbon. The VCEA does reference the Social Cost of Carbon, and Commission regulations will need to be updated to account for the changes in the law. The General Assembly, through the VCEA and the Grid Transformation and Security Act of 2018, has established that Virginia must make the transition to a zero-carbon economy. For example, in 2018, the General Assembly passed legislation that provides that 5,500 megawatts of new wind and solar-powered generation is in the "public interest" for Commission proceedings, thereby reducing the hurdle for Commission approval.[28]

Yet the Commission has identified a tension between its historic mandates and the renewable energy directives. In a recent decision, the Commission expressed frustration over the cost of a small, 12-megawatt, offshore wind installation (the Coastal Virginia Offshore Wind ("CVOW") Project), but still approved of the facility as it was deemed to be in the public policy of the Commonwealth as set by the legislature.[29] The Commission stated as follows:

> "The Commission finds - as a purely factual matter based on this record - that the proposed CVOW Project would not be deemed prudent as that term has been applied by this Commission in its long history of public utility regulation or under any common application of the term. The Commission further finds, however, that as a matter of law the new statutes governing this case subordinate the factual

[25] *See* 20 VAC § 5-302-10
[26] 20 VAC § 5-302-35
[27] *Id.*
[28] *See* Va. Code § 56-585.1:4; Va. Code § 56-46.1(D).
[29] Final Order, *Petition of Va. Elec. & Power Co. For a prudency determination with respect to the Coastal Virginia Offshore Wind Project*, PUR-2018-00121 (Nov. 2, 2018)

analysis to the legislative intent and public policy clearly set forth in the statutes quoted above and, thus, the instant Petition should be - and is hereby - approved."[30]

The Commission's struggle to resolve the petition on the CVOW Project suggests similar challenges may be ahead with regard to the Social Cost of Carbon. It remains unclear how the Commission will calculate the Social Cost of Carbon, and there is very little direction from the General Assembly in the VCEA on how such a calculation should be made. Former President Barack Obama's Executive Order 12866 provides some guidance. It was aimed at addressing the Social Cost of Carbon across multiple federal agencies.[31]

New guidance regulations from the State Corporation Commission, likely in consultation with the Virginia Department of Environmental Quality (which will administer Virginia's carbon regulations for stationary sources), will be necessary. The Institute for Policy Integrity at New York University School of Law has also developed significant expertise in this arena.[32]

## III. Small Renewable Energy Regulation by the Department of Environmental Quality

Solar and wind energy projects rated at 150 megawatts or smaller, it should be noted, do not need to obtain a Certificate of Public Convenience and Necessity from the Commission. Rather, such small, qualifying renewable projects obtain state approval through the Department of Environmental Quality's permit-by-rule process,[33] which ensures that "a project is deemed to have a permit if it contains all the components and meets the requirements of the regulation.[34] In general, the following components are needed for a renewable energy permit-by-rule:[35]

(1) Notice of Intent;
(2) Local government approval;
(3) Interconnection studies;
(4) Final Interconnection Agreement;
(5) Certification project does not exceed 150 MW;
(6) Air quality analysis;
(7) Cultural, wildlife and natural heritage resources assessments;
(8) Mitigation plan if appropriate;
(9) Certification if developer is utility or non-utility;
(10) Site map, context map, and operation plan;
(11) 30-day public comment period; and
(12) Permit fee.

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[30] *Id.* at 15
[31] *See* Council of Economic Advisers et al., *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (Aug. 2016), https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.
[32] *See, e.g.,* New York University School of Law, Institute for Policy Integrity, *Social Costs of Greenhouse Gases* (Feb. 2017), https://policyintegrity.org/files/publications/Social_Cost_of_Greenhouse_Gases_Factsheet.pdf
[33] Va. Code § 10.1-1197.6
[34] Virginia Department of Environmental Quality, *Renewable Energy*, https://www.deq.virginia.gov/Programs/RenewableEnergy.aspx (last visited April 25, 2020)
[35] Va. Code § 10.1-1197.6; *see also* 9 VAC § 15-60-010 *et seq.* (discussing requirements specific to solar projects in further detail); 9 VAC § 15-40-010 *et seq.* (discussing requirements specific to wind projects in further detail)

One potential roadblock in the DEQ permit-by-rule process is that it subjects qualifying small renewable energy projects to the discretion of local officials. Misinformation about the costs and benefits of wind and solar projects have led some municipalities around the country to exercise their authority to block renewable energy development. Columbia University School of Law, through its Sabin Center for Climate Change Law, has launched a Renewable Energy Legal Defense Initiative "to provide pro bono legal representation to community groups and local residents who support renewable energy development in their communities, but are facing opposition."[36] Closer to home, the Virginia Department of Environmental Quality has developed model renewable energy ordinances as part of its local government outreach on this issue.[37]

For very small, residential or homeowner-driven installations—wind and solar projects with capacity of up to 5 megawatts, or solar projects that cover less than 10 acres—the owner or operator of the small renewable energy project is not required by law to submit any notification or receive a permit from DEQ.[38] Additional exemptions for solar projects, regardless of their rated capacity or total covered acreage, includes those projects that are:

> (a) mounted on a single-family or duplex private residence;
> (b) mounted on one or more buildings less than 50 years old or, if 50 years of age or older, have been evaluated and determined by the Department of Historic Resources within the preceding seven years to be not VLR-eligible;
> (c) mounted over one or more existing parking lots, existing roads, or other previously distributed areas and any impacts to undistributed areas do not exceed an additional two acres; and
> (d) utilizing integrated PV only, provided that the building or structure on which the integrated PV materials are used is less than 50 years old or, if 50 years of age or older, has been evaluated and determined by DHR within the preceding seven years to be not VLR-eligible.[39]

While a state permit for small renewable energy projects may not be mandated, prospective customers for net-metered renewable energy projects are subject to additional notice and approval requirements pursuant to 20 VAC § 5-315-30 (Company Notification).[40]

## IV. Updating the Commission's Integrated Resource Planning Guidelines

One avenue to ensure compliance with EO 43 and the mandatory RPS is through each utility's integrated resource plan. Section 56-599 mandates that each electric utility in Virginia files an updated integrated resource plan ("IRP") with the Commission every three years. The Commission then has the discretion to "approve [actions by a utility] to diversify its generation supply portfolio

[36] *See* Columbia Law School and Columbia University Earth Institute, Sabin Center for Climate Change Law, *Renewable Energy Defense Initiative*, https://climate.law.columbia.edu/content/renewable-energy-legal-defense-initiative (last visited May 13, 2020)
[37] *See* Virginia Department of Environmental Quality, *DEQ's Local Outreach*, https://www.deq.virginia.gov/Programs/RenewableEnergy/ModelOrdinances.aspx (last visited May 13, 2020)
[38] *See* 9 VAC § 15-60-130; *see also* 9 VAC § 15-40-130
[39] 9 VAC § 15-60-130(A)(2)
[40] Net-metered projects are discussed in Chapter 2.

and ensure that the electric utility is able to implement an approved plan." Va. Code § 56-599(B)(6). The Commission has issued guidelines on the contents of a utility's IRP, which should be reviewed and amended to guide utilities' planning towards compliance with Executive Order 43 and the Virginia Clean Economy Act.[41]

First, the Integrated Resource Planning Guidelines will likely need to require greater analysis of specific demand-side management programs. The Integrated Resource Planning Guidelines currently require each utility to develop an integrated resource plan which incorporates "comprehensive analysis of all existing and new resource options," including assessment of "the potential costs and benefits of programs that promote demand-side management," but do not specify particular DSM programs that should or shall be considered.[42] The Guidelines state, "[f]or purposes of these guidelines, peak reduction and demand response programs and energy efficiency and conservation programs will collectively be referred to as demand-side options."[43] The Guidelines might also be amended to require analysis of additional "demand-side options," including net energy metering and integration with community-based renewable energy programs.

The Integrated Resource Planning Guidelines might also be amended in light of the Virginia Clean Economy Act to require utilities to consider the benefits of forgone carbon emissions in their analyses of "all existing and new resource options," including using the Social Cost of Carbon to estimate cost savings. The Guidelines recognize the need for a utility to demonstrate in its Integrated Resource Plan how its choices of resource options were "considered and chosen by the utility for satisfaction of native load requirements and other system obligations necessary to provide reliable electric utility service, at the lowest reasonable costs, over the planning period."[44] A crucial aspect of providing reliable electric service at the lowest reasonable costs could very well be related to reductions in carbon emissions and the minimizing the economic harm from those emissions, along with complying with regulatory mandates on greenhouse gases at the lowest cost.

A Social Cost of Carbon analysis cannot be a stand-alone item grafted on to a pre-existing IRP document. Rather, the Commission's Guidelines likely need to be updated throughout to ensure that the Social Cost of Carbon is weaved into the entire process of Integrated Resource Planning. For example, in Section C(2) of the Guidelines, providing the general requirements for an Integrated Resource Plan's "Option analyses," the Commission asks for a "comprehensive analysis of all existing and new resource options (supply- and demand-side), including costs, benefits, risks uncertainties, reliability, and customer acceptance where appropriate."[45] Here again, "carbon emissions" need to be explicitly addressed. Section C(2)(d) would be similarly revised to provide that an IRP's "Evaluation of Resource Options" considers "system needs," including the need to achieve zero carbon emissions by 2045 for Dominion or by 2050 for Appalachian Power.

[41] Virginia State Corporation Commission, *Integrated Resource Planning Guidelines*, https://www.scc.virginia.gov/getattachment/2cd5741c-51d9-4003-b43f-85a6680a3608/irp.pdf (last visited Apr. 25, 2020).
[42] *Id.* at 2
[43] *Id.* at 2-3
[44] *Id.* at 2
[45] *Id.*

Section F "Contents of the Filing," which specifies the data a utility "shall" provide in its IRP, should also be updated. Section F(2)(b)(ii) Assessment of Supply-Side Resources might be updated to require, for example, analysis of "supply-side energy resources evaluated but rejected, a description of the resource; the potential capacity and energy associated with the resource; estimated costs; *any foregone carbon reductions and a Social Cost of Carbon analysis of the resource,* and the reasons for the rejection of the resource." Finally, the Commission's Guidelines on forecasting will also need to account for a Social Cost of Carbon.

## V. Updating Status Reports Filed Pursuant to Va. Code § 56-596 B

Section 56-596(B) of the Code of Virginia directs the Commission to provide an update by September 1 of each year on the status of the implementation of the Virginia Electric Utility Regulation Act. The Commission released its most recent update in August 2019 pursuant to this directive.[46] Here again, the Commission will need to determine how to account for the Social Cost of Carbon in these reports, and how to account for the transition to producing 30% of Virginia's electricity from renewable energy sources by 2030 and 100% from carbon-free sources by 2045 or 2050.

## VI. Conclusion

The environmental impacts of existing and new coal-and gas-fired power plants—regulated by the U.S. EPA and the Virginia Department of Environmental Quality through air, water, and waste permitting decisions—are undoubtedly significant. But throughout the country, state public utility commissions (in Virginia, the State Corporation Commission) are where "the rubber meets the road" in terms of an initial decision to build or retire these plants. As this Chapter documents, the State Corporation Commission will be called upon to make several critical decisions in the coming years on the integration of renewable resources, the expansion of energy-efficiency programs, and the allocation of costs. Chief among these will be the development of guidelines on the Social Cost of Carbon – *i.e.,* how costs and benefits will be calculated and how those calculations will be used in the Commission's decision-making process.

[46] *See* Virginia State Corporation Commission, *Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant to § 56-596 B of the Code of Virginia* (Aug. 2019), https://scc.virginia.gov/getattachment/9c541d40-447a-40b2-848a-5cfa2cbcf0e3/2019_veur.pdf.

CHAPTER 4:
THE ROLE OF THE FEDERAL ENERGY REGULATORY COMMISISON AND PJM

## I. Introduction

Virginia's ability to implement and execute a plan to transition to a clean energy grid is not entirely within the Commonwealth's control. Virginia utilities—Dominion Energy, Appalachian Power, Old Dominion Electric Cooperative, and Kentucky Utilities—are all members of PJM Interconnection, the nation's largest regional transmission organization ("RTO"). PJM operates wholesale energy, capacity, and ancillary services markets. It "coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia."[1] As a result, PJM's policies and those of Federal Energy Regulatory Commission ("FERC" or "the Commission")will likely have a significant impact on the electricity generation portfolio that is available on the grid and accessible to Virginia utilities.

The structure of PJM, especially the capacity market, is generally unfavorable to new renewable development and thus may present an impediment to E.O. 43. The Minimum Offer Price Rule ("MOPR"), which was expanded by a recent FERC decision in an ongoing dispute regarding a piece of PJM's capacity market, further threatens to exacerbate the problems with the capacity market.

To be clear, these challenges can be overcome and the Commonwealth undoubtedly can put the necessary laws, regulations, and incentives in place to produce thirty percent of Virginia's electricity from renewable energy sources by 2030 and one hundred percent of Virginia's electricity from carbon-free sources by 2050. That said, it is essential to understand that challenges within PJM at the outset of plan development. Accordingly, this section of the report provides an analysis of PJM's structural impediments to E.O. 43, looking at (1) the Minimum Offer Price Rule; and (2) Structural Issues with PJM.

## II. Minimum Offer Price Rule

The capacity market compensates electricity generation resources (*e.g.,* power plants) and demand response resources (*e.g.,* equipment that can be powered down to reduce energy consumption, or on-site generators at a factory) that will guarantee their availability at any time they are called upon in a given delivery year.[2] This compensation comes from an annual auction process that typically occurs three years before the commitment delivery year. Of Virginia's investor-owned utilities, only Dominion participates in the capacity market. Appalachian Power participates in an

[1] PJM Interconnection, *Who We Are*, https://www.pjm.com/about-pjm/who-we-are.aspx (last visited May 18, 2020)
[2] PJM Interconnection, *Understanding the Differences Between PJM's Markets* (Mar. 6, 2019), https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/understanding-the-difference-between-pjms-markets-fact-sheet.ashx

alternative program known as the Fixed Resource Requirement ("FRR"), which is discussed in more detail below.

The MOPR sets a bidding price floor for certain new resources bidding into the capacity auction that, according to FERC, may artificially depress the market price.[3] For its entire history, the MOPR has only applied to certain new natural gas fired generation facilities. Yet in 2016, a natural gas generator filed a complaint with FERC alleging that any resource that receives "state support" is artificially depressing the market price and therefore should be subject to the MOPR.[4] That complaint launched a protracted, iterative process to revise the MOPR in a way that may harm renewable energy development.

The Minimum Offer Price Rule revision process recently resulted in a FERC order ("the December 2019 Order") that would expand the MOPR to cover any resource benefitting from a state subsidy.[5] The definition of subsidy in that order is both broad and vague and likely covers renewables built pursuant to a mandatory renewable portfolio standard ("RPS"). PJM responded with a compliance filing that, if approved, will include the RPS mandated by the Virginia Clean Economy Act ("VCEA") as a state subsidy.[6]

The general concern regarding the expanded MOPR is that renewable resources may not clear the capacity auction if subjected to a bidding price floor and thus would be cut off from an important source of income. That income could, in theory, be the difference between a resource being built and not being built. Prominent, national environmental organizations have filed suit in the U.S. Court of Appeals for the District of Columbia Circuit against FERC, challenging the MOPR, which they have labeled a "de facto bailout of coal and gas power plants at the expense of state clean energy policies."[7]

In Virginia, the short-term concern is that the MOPR will disincentivize renewable development, which might have occurred at an even faster pace than that mandated by the recently enacted VCEA. The long-term concern is that if Dominion's renewable resources do not clear the market, the utility could be forced to purchase duplicative capacity from out-of-state, carbon-polluting generation sources.[8] The effect of this would be Virginia ratepayers subsidizing those out-of-state emitting sources, violating the spirit of E.O. 43 and artificially propping up coal- and/or gas-fired generation that otherwise would have been retired.

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[3] PJM Interconnection, *PJM Open Access Transmission Tariff*, Attachment DD § 5.14(h) (2017), https://www.pjm.com/directory/merged-tariffs/oatt.pdf
[4] Complaint Requesting Fast Track Processing, *Calpine Corp. v. PJM Interconnection, L.L.C.* (filed Mar. 21, 2016)
[5] *Calpine Corp.*, 169 FERC ¶ 61,239 (2019)
[6] Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, And Request for an Extended Comment Period of at Least 35 Days, PJM Interconnection, L.L.C., *Calpine Corp. v. PJM Interconnection, L.L.C.* (filed Mar. 18, 2020)
[7] Press Release, NRDC*, FERC Sued Over Unlawful Rule that Props Up Gas, Coal Plants* (Apr. 21, 2020), https://www.nrdc.org/media/2020/200421-0
[8] *See Calpine Corp.*, 169 FERC ¶ 61,239 at 25 (Glick, Comm'r, dissenting)

Although many regulatory observers hoped that FERC would modify the order upon rehearing in order to avoid the obviously illogical impact that the MOPR would have on lower-cost renewable energy development, on April 16, 2020 the Commission denied all relevant rehearing requests and reaffirmed the substance of its order.[9]

There are now two actions that Virginia can take to mitigate the impact of the December 2019 Order: litigation and withdrawal from the capacity market. Litigation would be subject to long timelines that often accompany court proceedings but may completely overturn the FERC order. Withdrawing from the capacity market can be done immediately but comes with technical challenges that may not make it the best long-term solution.

**a. Litigation**

As stated above, a legal challenge, initiated by NRDC, the Sierra Club, Environmental Defense Fund, and the Union of Concerned Scientists, has been filed in the U.S. Court of Appeals for the D.C. Circuit.

A legal challenge looking to overturn the FERC order might argue that the order encroaches on jurisdiction set aside exclusively for the states in the Federal Power Act.[10] Pursuant to the Federal Power Act, FERC's authority is largely limited to *wholesale* transactions for electric power across state lines. Retail sales to end-use customers are regulated by state public service commissions (in Virginia, the State Corporation Commission). The Federal Power Act goes on to specify that FERC "shall not have jurisdiction [except in limited, delineated circumstances] … over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in *intra*state commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[11]

Two decisions from the Supreme Court of the United States in 2016 helped to delineate the line between federal (FERC) and state authority. In *Hughes v. Talen Energy Marketing, LLC*, the Court specifically addressed a Maryland program aimed at addressing concerns with the Minimum Offer Price Rule by providing "subsidies, through state-mandated contracts, to a new generator, but condition[ed] receipt of those subsidies on the new generator selling capacity into a FERC-regulated wholesale auction."[12] Because the Maryland scheme was designed to "intrude on FERC's authority over interstate wholesale rates," it was found to have been pre-empted by the Federal Power Act.[13]

The Court was careful to explain, however, that:

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[9] *Calpine Corp.*, 171 FERC ¶ 61,035 (2020) (Order on Rehearing and Clarification). The Commission granted partial rehearing for the limited purpose of excluding more planned facilities with existing agreements from the MOPR but changed nothing for facilities that have not yet been planned or existing facilities that fall outside the exemptions. *Id.*
[10] See 16 U.S.C. § 824(b)(1)
[11] *See id.* (emphasis added)
[12] *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1292 (2016)
[13] *See id.* at 1297-98 (applying the Supremacy Clause, U.S. Const., Art. VI, cl. 2)

> Our holding is limited: We reject Maryland's program only because it disregards an interstate wholesale rate required by FERC. … Nothing in this opinion should be read to foreclose Maryland and other States from encouraging production of new or clean generation through measures 'untethered to a generator's wholesale market participation.' So long as a State does not condition payment of funds on capacity clearing the auction, the State's program would not suffer from the fatal defect that renders Maryland's program unacceptable.[14]

In other words, states remain free to enact programs like the VCEA; the Federal Power Act in no way pre-empts them.

Yet that leaves unresolved whether FERC may leverage its authority under the Federal Power Act in a way that effectively disrupts state, retail initiatives like the VCEA. In *FERC v. Electric Power Supply Association,* the Court considered this issue in a challenge from an electricity industry trade group to a FERC order promoting demand response as a means of conserving energy. The Court reaffirmed that the Federal Power Act set aside "a zone of exclusive state jurisdiction."[15] It went on to explain:

> As pertinent here, § 824(b)(1)—the same provision that gives FERC authority over wholesale sales—states that "this subchapter," including its delegation to FERC, 'shall not apply to any other sale of electric energy.' Accordingly, the Commission may not regulate either within-state wholesale sales or, more pertinent here, retail sales of electricity (i.e., sales directly to users).[16]

The Court did not, however, strike down the demand response regulation at issue. Rather, it upheld FERC's promotion of demand response despite the trade association's claim that it was "effectively" setting rates at the retail level through its indirect impacts: "The modifier 'effective' is doing quite a lot of work in that argument—more work than any conventional understanding of rate-setting allows."[17] The Court was clear that challenges to a FERC rule would need to point to more than indirect, incidental effects on state-regulated retail markets. The majority reasoned, "It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other."[18]

Still, the Court reasoned that FERC could not "take an action" explicitly designed to influence retail sales "no matter how direct, or dramatic, its impact on wholesale rates."[19] FERC could not, for example, mandate retail purchases by end-use customers as a means of stabilizing the wholesale market, because such a regulation would "specif[y] terms of sale at retail—which is a

[14] *Id.* at 1299 (internal citation omitted)
[15] *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 767 (2016)
[16] *Id.* at 767-68
[17] *Id.* at 777
[18] *Id.* at 776
[19] *Id.* at 775

job for the States alone."[20] With respect to the MOPR and its application to new, renewable generation, FERC very well may have transgressed, as FERC explicitly stated that it took action in response to "state support for renewable and nuclear resources."[21] Meanwhile, the impact to wholesale rates is only indirect: it will only result in a higher clearing price when the auction clears with renewable sources alone. There are also multiple arguments to be made that the order is arbitrary and capricious.

### b. Withdrawing from the Capacity Market

An immediate step that could be taken to mitigate the impacts of the MOPR order would be to withdraw from the capacity market and participate in the FRR alternative. The FRR alternative is a means for utilities to meet resource adequacy requirements without participating in the capacity auction process.[22] Under this program, a utility that has demonstrated to the satisfaction of PJM that it has secured its own capacity covering the projected needs of its entire service territory, plus a reserve margin, may exit the capacity auction process while remaining in PJM's other markets. Simply stated, the FRR alternative is an "opt out." A utility electing the FRR alternative is committing to PJM that it will secure its capacity resource needs outside of PJM's market.

If Dominion Energy notified PJM that it was taking the FRR opt-out, such action would clear the way for the VCEA and would allow new, renewable generation to be procured by the utility and be counted toward resource adequacy requirements while avoiding the double payments problem described above with the MOPR.

A utility must provide PJM with notice of its intent to elect the FRR alternative four months before the capacity auction for the delivery year in which the utility intends to start using the FRR alternative. Once committed, the utility must use the FRR alternative for at least five years, at which point it may continue to use the program on a year-to-year basis. After utilizing the FRR alternative for at least five years, the utility may elect to rejoin the capacity auction process by giving notice two months before the next auction. After terminating participation in the FRR alternative, a utility may not reelect that option for five years.

Virginia is particularly well-suited to transition to the FRR alternative. While other states might be concerned about the regulatory learning curve, Virginia has overseen Appalachian Power participating in the FRR alternative since 2006. Virginia's other investor-owned utility, Dominion Energy, has publicly indicated that it could make a seamless transition to the FRR alternative if necessary and has even indicated a willingness to do so voluntarily.[23]

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[20] *Id.*

[21] *Calpine Corp.*, 169 FERC ¶ 61,239 at 21-22 (2019)

[22] *See* Capacity Market Operations, PJM Interconnection, *PJM Manual 18: PJM Capacity Market* 201 (Rev. 44 2019), https://www.pjm.com/~/media/documents/manuals/m18.ashx

[23] *Dominion Energy, Inc Q4 2019 Earnings Call Transcript,* Motley Fool (Feb. 11, 2020), https://www.fool.com/earnings/call-transcripts/2020/02/11/dominion-energy-inc-d-q4-2019-earnings-call-transc.aspx

If Virginia chooses to mandate a switch to the FRR, it might require new, state legislation. And there are some technical challenges that would need to be evaluated before pursuing this course of action. First, the FRR alternative requires a certain amount of capacity to be located in each Locational Deliverability Area ("LDA"), which is a subregion within the PJM territory. Marrying this requirement with E.O. 43 would require confirming the ability to site sufficient renewable energy resources within each LDA. Planning challenges would have to be overcome as well, since a FRR capacity plan would necessarily require projections about renewable resources that have not yet been constructed or are still under construction. Finally, there would need to be an analysis of the costs and benefits of locking Virginia's utilities into the FRR alternative for a minimum of five years.

## III. Structural Issues with PJM

The MOPR dispute is just the latest example of PJM's capacity market hindering renewable energy development. Even though the new MOPR has not yet taken effect, PJM is the only regional transmission organization to have added more carbon-emitting sources than renewable sources to its generation mix since 2012, with 75% of new generation coming from carbon-emitting sources.[24]

To put this data point into context, it is worth noting that the U.S. Department of Energy's Energy Information Administration (EIA) forecasts that three-fourths (76%) of new generating capacity in 2020 will come from wind and solar resource additions.[25] Just last year, *existing* renewable generation exceeded the amount of electricity generated by coal-fired power in some months.[26] And, in 2020, the total amount electricity produced from renewable sources is projected to surpass coal-fired power.[27] Yet PJM appears to have designed rules that counter these nationwide trends.

Part of the issue is that to participate in the PJM capacity market, resources must guarantee availability for the entire delivery year. This requirement is not necessary to ensure reliability given that PJM's peak load varies greatly by season. A more nuanced program, which would allow seasonal resources to bid into the capacity market, could achieve the required reserve margin for each season with less overall capacity.

Capacity markets also disadvantage the push for 100% renewable generation in other ways, including over-procuring capacity, which provides funding for dispatchable, carbon-emitting

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[24] Miles Farmer & Amanda Levin, *Comparing America's Grid Operators On Clean Energy Progress: PJM is Headed for Climate Disaster*, Utility Dive (July 2, 2019), https://www.utilitydive.com/news/comparing-americas-grid-operators-on-clean-energy-progress-pjm-is-headed/557994/

[25] Suparna Ray, *New electric generating capacity in 2020 will come primarily from wind and solar*, EIA (Jan. 14, 2020), https://www.eia.gov/todayinenergy/detail.php?id=42495

[26] Patricia Hutchins, *U.S. electricity generation from renewables surpassed coal in April*, EIA (June 26, 2019), https://www.eia.gov/todayinenergy/detail.php?id=39992

[27] *See* Brad Plumer, *In a First, Renewable Energy Is Poised to Eclipse Coal in U.S.*, N.Y. Times (May 13, 2020), https://www.nytimes.com/2020/05/13/climate/coronavirus-coal-electricity-renewables.html; EIA, *Short-Term Energy Outlook* (May 2020), https://www.eia.gov/outlooks/steo/archives/May20.pdf

generation that is kept "on call."[28] In his dissent of the December 2019 Order, FERC Commissioner Richard Glick even acknowledged that mandatory capacity markets may "no longer [be] a sensible approach to resource adequacy at a time when states are increasingly exercising their authority under the FPA to shape the generation mix."[29]

The structural problems with PJM's capacity market are exacerbated by the fact that in PJM, unlike in many other RTOs, states are not voting members and thus do not have the same degree of leverage when requesting inclusion of their policies in PJM proposals.[30] PJM states are members of the Organization of PJM States, Inc ("OPSI"). OPSI's role in resource adequacy proposals is to submit collective comments on behalf of the states.

In contrast, states in other RTOs having varying levels of power. The role of state-level policymakers therefore may partially explain the differences in the mix of new generation among the RTOs. The Southwest Power Pool (SPP), for example, grants the most power to states. SPP bylaws give a Regional State Committee, consisting of public utility commissioners from member states, the authority to craft resource adequacy policy and submit associated filings with FERC. The current program for resource adequacy in SPP is very similar to PJM's FRR alternative; utilities are responsible for procuring their own capacity and must do so within the constraints of state law. As a result, SPP has been the most successful RTO at building new renewable resources, with 84% of new resources built in the SPP service territory since 2012 being classified as renewable.

Another structural problem with PJM stems from its role as an interstate market directly under the jurisdiction of FERC. Recent FERC actions outside of the MOPR controversy highlight additional impediments to delivering 30% of Virginia's electricity from renewable energy sources by 2030 and 100% carbon-free sources by 2050. FERC has indicated that its next targets might be voluntary Renewable Energy Certificates (RECs),[31] renewables offering services in the energy market,[32] and non-energy producing resources, such as energy efficiency and demand response.[33] FERC also recently reaffirmed PJM's Variable Resource Requirement Curve which is responsible for the RTO's chronic over-procurement of carbon-polluting capacity.[34] Industry advocates are preparing to leverage FERC advocacy as a means of blunting initiatives like the VCEA. Recently, the New England Ratepayers Association, an organization that has long advocated against renewable

[28] Rob Gramlich & Michael Goggin, *Too much of the Wrong Thing: The Need for Capacity Market Replacement or Reform* 6-19 (2019), https://gridprogress.files.wordpress.com/2019/11/too-much-of-the-wrong-thing-the-need-for-capacity-market-replacement-or-reform.pdf

[29] *Calpine Corp.*, 169 FERC ¶ 61,239 at 28 (Glick, Comm'r, dissenting)

[30] Jennifer Chen & Gabrielle Murnan, Duke Univ., Nicholas Inst., *State Participation in Resource Adequacy Decisions in Multistate Regional Transmission Organizations* (2019), https://nicholasinstitute.duke.edu/sites/default/files/publications/state_participation_in_resource_adequacy_decisions_web.pdf

[31] *Calpine Corp.*, 171 FERC ¶ 61,035 at n.807, n.808 (2020) (order on rehearing and clarification)

[32] FERC, *Commission Meeting*, Capitol Connection at 37:09 (Apr. 16, 2020), ferc.capitolconnection.org (remarks of Comm'r Danly)

[33] *Id.*

[34] *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,040 (2020) (order denying rehearing)

energy development but has failed to disclose its membership, filed a petition seeking that FERC exercise its federal control over small, residential solar projects that participate in state-managed net metering programs.[35]

These concerns notwithstanding, PJM may be willing to work with the Commonwealth to address the structural deficiencies inhibiting cost-effective renewable energy development. PJM's compliance filing in the MOPR proceeding was received by representatives of the wind and solar industries with cautious optimism:

> "PJM's proposal provides the flexibility necessary for renewable resources to demonstrate that they are among the lowest cost and most reliable sources of capacity available today," Amy Farrell, senior vice president of government and public affairs for trade group American Wind Energy Association, said in a statement. …
>
> PJM's filing will allow renewable generators to "properly identify a project-specific bid price for bidding into the capacity market auctions" that provides a "better opportunity to compete on a level playing field with other capacity providers and to help meet states' clean energy goals," Katherine Gensler, Solar Energy Industries Association vice president of regulatory affairs, said in a statement.[36]

## IV. Conclusion

The impediments identified above should not be seen as insurmountable obstacles to implementation of E.O. 43, but they must be taken seriously. Virginia may wish to investigate election of the FRR alternative for all utilities or withdrawal from PJM altogether. Although the portion of North Carolina served by Dominion Energy is within PJM, the remainder of North Carolina is not a part of any RTO. The same is true for most Southeastern states—Tennessee, South Carolina, Georgia, Alabama, and Florida. The takeaway here is that as the Commonwealth moves to implement E.O. 43, regulators will need to consider the costs and benefits of RTO participation for renewable energy expansion.[37]

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[35] Catherine Morehouse, *Secretive group's petition to FERC could 'end net metering as we know it,' lawyers say*, Utility Dive (Apr. 21, 2020), https://www.utilitydive.com/news/secretive-groups-petition-to-ferc-could-end-net-metering-as-we-know-it/576400/

[36] *See* Jasmin Melvin, et al., *PJM Market Participants See Brighter Path Forward Under MOPR Compliance Plan*, S&P Global Market Intelligence (Mar. 20, 2020), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/pjm-market-participants-see-brighter-path-forward-under-mopr-compliance-plan-57604359

[37] Steven Shparber, *Are Regional Transmission Organizations the Future for Renewables in the Southeast?*, Nelson Mullins Riley & Scarborough LLP (Aug. 28, 2019), https://www.nelsonmullins.com/idea_exchange/insights/are-regional-transmission-organizations-the-future-for-renewables-in-the-southeast

CHAPTER 5:
APPROACHES TO DECARBONIZATION IN OTHER STATES

Virginia is one of many states that have taken legislative or executive action to establish a goal of wholly decarbonizing the electricity sector by 2050 or sooner. At the time of this writing, twelve states (including Virginia), the District of Columbia, and Puerto Rico have all adopted zero-carbon initiatives.[1] These jurisdictions account for one-third of the country's population and thus represent significant momentum in developing carbon-free energy.[2]

The Virginia Clean Economy Act, as discussed in Chapter 2 of the Legal Report, establishes a mandate of zero-carbon electricity generation in Dominion Energy's service territory by 2045 and in Appalachian Power's service territory by 2050. The Virginia legislative program is buttressed by Governor Northam's Executive Order 43, which directs state agencies to develop a plan to produce 30% of Virginia's electricity from renewable energy sources by 2030 and 100% from carbon-free sources by 2050. In addition, the following states have also adopted similar 100% clean energy targets, either by legislation or by executive order:

- In the District of Columbia, legislation sets a zero-carbon target date of 2032.
- In New York, legislation sets a target date of 2040;
- In Hawaii, California, Washington State, and New Mexico, legislation sets a target date of 2045;
- In Colorado, Maine, Nevada, and Puerto Rico, legislation sets a target date of 2050;
- In Connecticut, an executive order sets a target date of 2040;
- In Wisconsin, Minnesota, and New Jersey, executive orders set a target date of 2050.

The policies that other states have adopted to reach these targets are varied, but the core structure is quite similar.[3] Indeed, New York enacted its landmark New York Climate Leadership and Community Protection Act in the summer of 2019, which, like the VCEA, takes an omnibus approach to carbon emission reductions.[4]

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[1] *See* Lori Bird & Tyler Clevenger, *2019 Was a Watershed Year for Clean Energy Commitments from U.S. States and Utilities,* World Resources Institute (Dec. 20, 2019), https://www.wri.org/blog/2019/12/2019-was-watershed-year-clean-energy-commitments-us-states-and-utilities

[2] *See* US Census Bureau*, QuickFacts*, https://www.census.gov/quickfacts/geo/chart/US/PST045219 (last visited May 25, 2020) (providing a 2019 estimate of total U.S. population of 328,239,523; the same data set provides population estimates for the fourteen jurisdictions listed above totaling to 110,981,355, or 33.8% of the country's estimated population)

[3] *See, e.g.,* Conn. Exec. Order No. 3 (Sept. 3, 2019), https://portal.ct.gov/-/media/Office-of-the-Governor/Executive-Orders/Lamont-Executive-Orders/Executive-Order-No-3.pdf; Minn. Exec. Order No. 19-37, 44 Minn. Reg. 692 (Dec. 9, 2019), https://www.leg.state.mn.us/archive/execorders/19-37.pdf; N.J. Exec. Order No. 28, 50 N.J. Reg. 1394(b) (June 18, 2018), https://nj.gov/infobank/eo/056murphy/pdf/EO-28.pdf; Va. Exec. Order No. 43, 36 Va. Reg. 351 (Oct. 14, 2019), https://www.governor.virginia.gov/media/governorvirginiagov/executive-actions/EO-43-Expanding-Access-to-Clean-Energy-and-Growing-the-Clean-Energy-Jobs-of-the-Future.pdf; Wis. Exec. Order No. 38 (Aug. 19, 2019), https://docs.legis.wisconsin.gov/code/executive_orders/2019_tony_evers/2019-38.pdf

[4] *See* S. 6599, 2019-2020 Assemb., Reg. Sess. (N.Y. 2019), https://nyassembly.gov/leg/?default_fld=&leg_video=&bn=A08429&term=2019&Summary=Y&Actions=Y&Text=

All of these states have a mandatory renewable portfolio standard ("RPS"), which in some cases has a "clean energy" standard layered on top of the RPS to bridge the final gap between carbon-emitting energy and 100% carbon-free energy. About half of these jurisdictions also participate in a multi-jurisdiction, greenhouse gas emissions trading program, which may be tied to binding emissions reductions. To these twin pillars (intra-state targets and multi-state trading regimes), states add some combination of ambitious energy efficiency standards, renewable energy mandates, often with a focus on competitive procurement, and renewable energy financing measures to encourage individuals, not just utilities, to invest in renewable energy. Of course, this summary only represents a snapshot of how other states have approached the transition to carbon-free electricity. It is meant to be illustrative, not exhaustive.

## I. Renewable Portfolio Standards

All jurisdictions that set a target similar to E.O. 43 have enacted a mandatory renewable portfolio standard married to a separate and distinct zero-carbon, clean energy target. Depending on the jurisdiction, "clean energy" is defined as either "carbon-free" or "carbon-neutral" energy generation. The broader focus on "carbon-free" over "renewable" appears designed to allow the use of nuclear power in achieving some targets. Similarly, "carbon-neutral" leaves open the door to some forms of combustion-based generation (*e.g.*, biomass), provided measures are put in place to ensure offsetting of carbon pollution from these sources.

The relationship between "clean" and "renewable" is not so neat. Some resources—hydropower and nuclear power—are carbon-free but not usually included in state renewable portfolio standards while others—biomass and landfill gas—are sometimes defined as "renewable" but are not carbon-free.

For example, Washington has historically relied heavily on hydroelectricity, yet dams on the Snake and Columbia rivers have caused salmon die-offs, threatening not just the salmon but also the orcas (killer whales) who feed on them.[5] Under its clean energy standard, Washington-state utilities may count power generated by existing hydroelectric facilities but not new or expanded stations.[6]

In, New Mexico, "zero-carbon resource" is defined as "an electricity generation resource that emits no carbon dioxide into the atmosphere, *or that reduces methane emitted into the atmosphere in an amount equal to no less than one-tenth of the tons of carbon dioxide emitted into the atmosphere*, as a result of electricity production."[7] New Mexico law then separately defines "renewable energy resource" to include solar, wind, geothermal, *newer* hydropower (in contrast to Washington State's approach), biomass with "zero life cycle carbon emissions", and certain fuel cell and landfill gas resources.[8]

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Y; *see also* Jackson Morris & Miles Farmer, *Unpacking New York's Big New Climate Bill: A Primer,* NRDC (June 20, 2019), https://www.nrdc.org/experts/miles-farmer/unpacking-new-yorks-big-new-climate-bill-primer-0

[5] Giulia C.S. Good Stefani, *Washington State v. Trump in Fight to Save Salmon, Orcas,* NRDC (Feb. 8, 2019), https://www.nrdc.org/experts/giulia-cs-good-stefani/washington-state-v-trump-fight-save-salmon-orcas

[6] *See* Wash. Rev. Code § 19.405.050

[7] *See* New Mexico State Code § 62-16-3 (K) (emphasis added)

[8] *See* New Mexico State Code § 62-16-3 (H)

Because methane is a significantly more potent greenhouse gas than carbon dioxide, New Mexico's program allows for some non-renewable, combustion resources to continue to play a role in the state's energy mix so long as electricity producers take actions to reduce the state's methane emissions. Given the large amount of natural gas production ongoing in New Mexico, this approach incentivizes methane reductions in the fuel extraction process (through flaring or capture at natural gas wells) that would not be covered by a more traditional RPS initiative aimed solely at electricity generators.[9]

Needless to say, varying definitions of "renewable" and "clean" energy generation will influence the resources in which electric utilities choose to invest. The table below provides a summary of some of the renewable and clean energy targets that states have adopted.

| State | Authorities | Requirement(s) |
|---|---|---|
| California | Cal. Pub. Util. Code § 399.11 et seq.; Cal. Pub. Util. Code § 454.53 | • 60% renewable energy by 2030<br>• 100% clean energy by 2045 |
| Colorado | Colo. Rev. Stat. §§ 40-2-124, 40-2-125.5 | • 30% renewable energy by 2030 (less for small municipal utilities and electric cooperatives)<br>• 100% clean energy by 2050 for utilities serving over 500,000 customers if "technically and economically feasible," "in public interest," and consistent with 1.5 percent maximum rate increase |
| Hawaii | Haw. Rev. Stat. § 269-91 et seq. | • 40% renewable energy by 2030<br>• 70% renewable energy by 2040<br>• 100% renewable energy by 2045 |
| Maine | Me. Rev. Stat. Ann. tit. 35, § 3210 | • 80% renewable energy by 2030<br>• 100% renewable energy by 2050 |
| New Mexico | N.M. Stat. Ann. §§ 62-16-4; 62-15-34 | • 40% renewable energy by 2025<br>• 80% renewable energy by 2040<br>• 100% zero-carbon electricity by 2045 (2050 for rural electric cooperatives) |
| New York | N.Y. Pub. Serv. Law § 66-p | • 70% renewable energy by 2030<br>• 100% zero-emissions electricity by 2040 |
| Washington | Wash. Rev. Code §§ 19.285, 19.405 | • 100% greenhouse gas neutral by 2030<br>• 100% renewable or zero-emitting by 2045 |

[9] *See* New Mexico Bureau of Geology & Mineral Resources, *Oil & Gas Program,* New Mexico Tech, https://geoinfo.nmt.edu/resources/petroleum/home.html (last visited May 25, 2020) (describing New Mexico's role as an oil and natural gas producing state)

| | | |
|---|---|---|
| District of Columbia | D.C. Code § 34-1431 et seq. | • 100% renewable energy by 2032 |
| Puerto Rico | P.R. SB 1121 | • 40% renewable energy by 2025<br>• 60% renewable energy by 2040<br>• 100% renewable energy by 2050 |

## II. Carbon Pricing Programs

Many states with binding zero-carbon targets for the electricity sector also have their own emissions trading programs or participate in a multi-state trading program as a means of internalizing into the electricity generation process the societal cost of carbon pollution. These existing carbon pricing programs, such as the Regional Greenhouse Gas Initiative, all take a cap-and-trade approach. While a direct carbon tax has been widely discussed, no state has yet enacted such an approach.[10] The Hawaii State Senate did pass a carbon tax bill earlier in 2020, but the measured was stalled, at least in part, after the legislature was forced into a recess by the COVID-19 pandemic.[11]

California, if it were a nation, would be the world's fifth largest economy (larger than Mexico and Canada *combined*) by gross domestic product.[12] It has adopted its own, intra-state emissions trading program, which now covers industrial facilities, electricity suppliers, fossil fuel distributors, and suppliers.[13] The program seeks to reduce emissions 40% between 2020 and 2030 and 80% between 2020 and 2050.[14] It has been amended numerous times since its initial adoption, including to add provisions for linkage to other emissions trading programs provided that they have requirements accounting for offsets and enforcement provisions at least as strict as California's.[15] California has linked its emissions program with Quebec and temporarily with Ontario, but it has yet to link with any jurisdictions in the United States.[16]

Washington adopted the Clean Air Rule, Wash. Admin. Code § 173-442-010 to -0370, which sought to establish a similar greenhouse gas emissions trading program to cover major stationary sources and fossil fuel distributors. The Rule was adopted in 2016, but it has been suspended since 2018, following a challenge to Department of Ecology's authority to regulate indirect emitters, such as natural gas distributors and fuel suppliers.[17]

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[10] *See e.g.,* Citizens' Climate Lobby, *Why we Support A Price on Pollution,* https://citizensclimatelobby.org/why-we-support-a-price-on-pollution/ (last visited May 28, 2020) (national organization discussing arguments in favor of a carbon fee approach)

[11] *See* S.B. 3150, 30th Leg. (Haw. 2020)*; see also* Ryan Finnerty, *Could Hawaii Pass the Country's First Tax on Carbon Emissions?,* Hawaii Public Radio (Mar. 9, 2020) https://www.hawaiipublicradio.org/post/could-hawaii-pass-countrys-first-tax-carbon-emissions#stream/0

[12] State of California Department of Finance, *Gross State Product,* http://www.dof.ca.gov/Forecasting/Economics/Indicators/Gross_State_Product/ (last visited May 25, 2020) (providing data via Excel spreadsheet showing California's world ranking for gross domestic product)

[13] Cal. Code. Regs., tit. 17, §§ 95801-96022; Cal. Code. Regs., tit. 17, § 95851

[14] *See id.* § 95841

[15] Cal. Gov. Code §12894(f); Cal. Code Regs., tit. 17, § 95941

[16] *See* California Air Resources Board, *Linkage,* https://ww3.arb.ca.gov/cc/capandtrade/linkage/linkage.htm (last visited May 25, 2020)

[17] *See Ass'n of Wash. Bus. v. Dep't of Ecology*, 455 P.3d 1126 (Wash. 2020) (upholding the Clean Air Rule as applied to direct emitters and striking down the rule as applied indirect emitters)

The most prominent cap-and-trade program in the United States is the Regional Greenhouse Gas Initiative ("RGGI"), which benefits from participation by ten states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont).[18] Virginia is poised to become the eleventh state within the RGGI regime.[19]

## III. Mandatory Emissions Reporting and Reductions

Many states that have taken aggressive action to combat climate change, such as decarbonizing the electricity sector, have also created mandatory reporting systems for their greenhouse gas emissions. Of the jurisdictions with a 100% zero-carbon target, only New Mexico, Puerto Rico, and the District of Columbia lack a greenhouse gas reporting requirement. These systems build upon federal and international reporting requirements.[20] Indeed, EPA has implemented, since 1993, national monitoring, reporting, and recordkeeping regulations to track carbon dioxide emissions from stationary sources, like power plants.[21] Often, states' emissions reporting is tied to greenhouse gas emissions reduction targets, which in turn may be tied to an emissions trading program, like the Regional Greenhouse Gas Initiative. California, New York, and Washington (subject to revision post-litigation) are all examples of such linkages.

The table below provides an overview of some of the leading, state greenhouse gas reporting requirements and reduction targets.

| State | Reporting and Reduction Requirements |
|---|---|
| California | • Annual reporting and third-party verification of emissions (Cal. Health & Safety Code § 38530; Cal. Code Regs. tit. 17, §95100 et seq.)<br>• Emission reduction to 1990 levels by 2020, 40% below by 2030, and 80% below by 2050 (Cal. Health & Safety Code §§ 38550, 38566; Cal. Code. Regs., tit. 17, § 95841) |
| Colorado | • Inventory at least every two years (Colo. Rev. Stat. § 25-7-140(2)(a)(I))<br>• Projections of emissions in five-year increments as part of inventory (Colo. Rev. Stat. § 25-7-140(2)(a)(II))<br>• Non-binding emissions reductions of 26% below 2005 levels by 2025, 50% by 2030, and 90% by 2050 (Colo. Rev. Stat. § 25-7-102) |
| Hawaii | • Emissions reduction to 1990 level by 2020 (Haw. Rev. Stat. § 342B-71) |
| Maine | • Annual reporting of emissions (06-096-137 Me. Code R. § 3)<br>• 45% below 1990 levels by 2030, 80% below by 2050 (Me. Stat. tit. 38, § 576-A) |
| New York | • Annual reports beginning in 2022 (N.Y. Envtl. Conserv. Law § 75-0105) |

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[18] The Regional Greenhouse Gas Initiative, *State Statutes and Regulations,* https://www.rggi.org/program-overview-and-design/state-regulations (last visited May 25, 2020)
[19] *See* 9 VAC §§ 5-140-6010 to 5-140-6440
[20] The EPA's Greenhouse Gas Reporting Program generally requires facilities, including electricity generation units, that emit over 25,000 metric tons of carbon dioxide equivalent per year to report emissions. *See* 40 C.F.R. Part 98.
[21] *See* 40 C.F.R. § 75.1 (establishing "requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO2), nitrogen oxides (NOx), and carbon dioxide ($CO_2$) emissions …"); 40 C.F.R. § 75.10(a)(3) (requiring facility owners or operators to "determine $CO_2$ emissions" using a continuous emission monitoring system (CEMS) or other EPA-approved method)

| | |
|---|---|
| | • Emissions 40% below 1990 levels by 2030; 85% below by 2050 (N.Y. Envtl. Conserv. Law § 75-0107) |
| Washington | • Inventory every two years beginning in 2010 (Wash. Code Rev. § 70.235.020(1)(a))<br>• Emissions reduction to 1990 levels by 2020, 25% below by 2035, and 50% below by 2050 with separate targets for state agencies (Wash. Code Rev. § 70.235.020(2)) |

## IV. Internalizing the Cost of Greenhouse Gas Pollution

One goal of many zero-carbon initiatives is to require polluting industries to internalize the public health and environmental costs of fossil-fuel combustion—*i.e.*, to account for the social cost of carbon.[22] Several states—California, Colorado, Illinois, Maine, Minnesota, New York, and Washington state—have adopted social cost of carbon regulatory measures.[23] The Virginia Clean Economy Act requires, for the first time in Virginia, the use of a social cost of carbon metric in the approval process for any new power plant, but the law gives little guidance on how that cost is to be calculated, and how the cost (once calculated) will be used in permitting processes for new power plants. Rather, the VCEA simply provides, in its entirety, on this issue as follows:

> In any application to construct a new generating facility, the utility shall include, and the Commission shall consider, the social cost of carbon, as determined by the Commission, as a benefit or cost, whichever is appropriate. The Commission shall ensure that the development of new, or expansion of existing, energy resources or facilities does not have a disproportionate adverse impact on historically economically disadvantaged communities. The Commission may adopt any rules it deems necessary to determine the social cost of carbon and shall use the best available science and technology, including the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, published by the Interagency Working Group on Social Cost of Greenhouse Gases from the United States Government in August 2016, as guidance. The Commission shall include a system to adjust the costs established in this section with inflation.[24]

While the State Corporation Commission is required to use a social cost of carbon, other state agencies—the Department of Mines, Minerals and Energy and the Department of Environmental Quality—may wish to develop a metric for calculating the cost. The California Air Resources Board, for example, developed a social cost of carbon as part of its plan for meeting California's 2030 greenhouse gas reduction target.[25]

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[22] *See* Iliana Paul, *et al.*, *The Social Cost of Greenhouse Gases and State Policy,* Institute for Policy Integrity, New York University School of Law (Oct. 2017), https://policyintegrity.org/files/publications/SCC_State_Guidance.pdf
[23] *Id.* at 9-12.
[24] 2020 Va. Acts of Assembly, Ch. 1193 (codified at Va. Code § 56-585.1(A)(6), effective July 1, 2020).
[25] *See* California Air Resources Board, *California's 2017 Climate Change Scoping Plan* (Nov. 2017), https://ww3.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf; Iliana Paul, *et al.*, *The Social Cost of Greenhouse Gases and State Policy,* Institute for Policy Integrity, New York University School of Law, at 9 (Oct. 2017), https://policyintegrity.org/files/publications/SCC_State_Guidance.pdf

Over time, the quantification of these costs will bring transparency to the cost of fossil fuel generation resources and highlight when these resources are not economically viable. For example, Colorado will see ten of its fourteen coal-fired power plants close by 2036, while the remaining four are under review in the face of increasing competition from renewable energy.[26]

Although natural gas-fired units are facing increasing scrutiny for their cradle-to-grave emissions, California and Washington currently require coal plants to be at least as efficient as a combined-cycle natural gas plant.[27] Maine imposes a similar requirement.[28] This requirement creates a *de facto* moratorium on new coal plant construction. To reduce the impact of coal plant retirements on utility ratepayers, New Mexico has authorized the securitization of stranded costs to finance the replacement electricity sources at a lower interest rate than utility's rate of return on capital investments.[29]

Policies can also discourage continued investment in fossil fuel extraction and, indirectly, generation. Colorado and New Mexico are in a unique position as both states that have committed to carbon-free energy but also states where the fossil fuel industry has strong presence. Both states recently strengthened their ability to regulate oil and gas companies. Colorado shifted the regulatory priorities of fossil fuel production from cost-effectiveness and technical feasibility to "public health, safety, and welfare, the environment, and wildlife resources"[30] while giving more power to localities to regulate the siting of oil and gas operations.[31] Meanwhile, New Mexico restored by statute the state regulator's authority to enforce its Oil and Gas Act.[32] However, in its two most recent legislative sessions, New Mexico has seen efforts to ban fracking stall.[33]

## V. Energy Efficiency and Conservation

States have increasingly recognized the importance of energy efficiency to achieving their commitments. It is now conventional wisdom that the cheapest and cleanest kilowatt-hour is the one a utility never has to generate in the first place.[34] Thus, it is not surprising that over half of states, including all states that have a 100% zero-carbon target either by statute or by executive order, have binding energy efficiency requirements.

[26] Anne Imse, *The closure of Colorado coal-fired powerplants is freeing up water for thirsty cities*, Colorado Sun (Mar. 31, 2020), https://coloradosun.com/2020/03/31/water-windfall-colorado-coal-plant-closures-water/
[27] *See* Cal. Pub. Util. Code § 8341; Wash. Rev. Code § 80.80.040
[28] Me. Rev. Stat. § 585-K
[29] *See* N.M. Stat. Ann. §§ 62-18-1 to -23
[30] Colo. Rev. Stat. § 34-60-106(2.5)
[31] *See id.* § 29-20-104(1)(h)
[32] *See* N.M. Stat. § 70-2-31. In *Marbob Energy Corp. v. N.M. Oil Conservation Comm'n*, 206 P.3d 135 (N.M. 2009), the New Mexico Supreme Court held that only the attorney general could bring action to enforce the Oil and Gas Act, N.M. Stat. §§ 70-2-1 to -38.
[33] *See* S.B. 104, 54th Leg., 2nd Sess. (N.M. 2020)
[34] *See* Annie Gilleo, *New data, same results – Saving energy is still cheaper than making energy*, ACEEE, (Dec. 1, 2017), https://www.aceee.org/blog/2017/12/new-data-same-results-saving-energy; Maggie Molina, *Renewables Are Getting Cheaper But Energy Efficiency, On Average, Still Costs Utilities Less*, ACEEE (Dec. 18, 2018), https://www.aceee.org/blog/2018/12/renewables-are-getting-cheaper-energy

## A. Traditional Demand Side Management

Most states set incremental annual energy efficiency targets, which specify savings as a percentage of previous output, but some, like California and Hawaii, set cumulative energy efficiency targets. There may be an additional peak-shaving (demand response) requirement on top of incremental or cumulative efficiency targets, such as in Maine and Colorado. California has implemented time-of-use electricity rates to encourage customers to shift their energy needs to off-peak hours where possible.[35] To create better incentives to reduce energy demand, Maine and Washington, D.C. carry out their energy efficiency programs through third-party administrators, Efficiency Maine and the DC Sustainable Energy Utility.[36]

The table below summarizes states' energy efficiency targets.

| State | Energy Efficiency Target(s) |
|---|---|
| California | • All cost-effective programs mandate[37] (Cal. Pub. Res. Code § 25310)<br>• Cumulative doubling of energy savings by 2030 (Cal. Pub. Res. Code § 25310)<br>• Incremental targets that average 1.05% between 2018 and 2030 (Cal. PUC Decision 17-09-025) |
| Colorado | • Cumulative 5% savings and peak reduction from 2018 levels by 2028 (Colo Rev. Stat § 40-3.2-104)<br>• Annual 500 GWh (~1.7%) incremental savings and average of 491 MW in peak demand reduction between 2019 and 2023 (Colo. PUC Decision No. C18-0417) |
| Hawaii | • Cumulative savings of 4,300 GWh (30% of the baseline) between 2010 and 2030 (Haw. Rev. Stat. § 269-96; Haw. PUC Order, Docket 2010-0037, Order No. 30089) |
| Maine | • Cumulative savings of 20% from 2007 baseline by 2020 and 300 MW peak reduction by 2020[38] (Me. Rev. Stat. tit. 35-A, §10104)<br>• Efficiency Maine operates under an all cost-effective mandate though funding has been insufficient to achieve savings targets in recent years (Me. Rev. Stat. tit. 35-A, §10104) |

[35] Decision Adopting Policy Guidelines, *Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments*, Cal. PUC Rulemaking 15-12-012 (filed Dec. 17, 2015), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M172/K782/172782737.PDF

[36] *See* 2019 Me. Laws 313 (amending Me. Rev. Stat. tit. 35-A, §10104 to create a stronger presumption that programs proposed by Efficiency Maine should be approved for funding by the Public Utility Commission); *see also* D.C. Code § 8-1774.10 (assessing a fee on each kilowatt-hour of electricity sold to fund the DC Sustainable Energy Utility).

[37] Seven states—California, Connecticut, Maine, Massachusetts, Rhode Island, Vermont, and Washington—have enacted an all cost-effective programs requirement. New Hampshire has set a long-term all cost-effective efficiency goal. *See* Order 25,932, *Energy Efficiency Resource Standard*, N.H. PUC DE 15-137 (filed August 2, 2016), *https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-137/ORDERS/15-137_2016-08-02_ORDER_25932.PDF*

[38] Maine will fall significantly short of these targets. *See* Maine Efficiency Trust, *Triennial Plan IV (Fiscal Years 2020-2022)*, (Sept. 4,2019), https://www.efficiencymaine.com/triennial-plan-iv/

| | |
|---|---|
| Massachusetts | • All cost-effective programs mandate (Mass. Gen. Laws ch. 25, § 21)<br>• Cumulative savings of 3.45 million MWh (~2.7% per year) for 2019-2021, which does not include new fuel switching initiative (D.P.U. 18-110 through Mass. D.P.U. 18-119)<br>• Performance incentives and $50/MWh penalty for non-compliance (Mass. D.P.U. 18-110 through Mass. D.P.U. 18-119; Mass. Gen. Laws ch. 25, § 21) |
| Nevada | • Incremental savings of 1.18% in 2019, 1.14% in 2020, and 1.14% in 2021 (Nev. PUC Docket No. 18-06003)<br>• Savings may count for up to 10% of renewable portfolio requirements through 2024 (Nev. Rev. Stat. § 704.7821) |
| New Mexico | • Statutory 5% cumulative savings from 2020 baseline from 2021 through 2025 (N.M. Stat. Ann. § 62-17-5)<br>• Public Regulation Commission directed to develop targets for 2026-2030 (N.M. Stat. Ann. § 62-17-5) |
| New York | • 185 trillion Btus of end-use energy savings below the 2025 energy-use forecast of which utilities should provide 31 trillion (NY PSC Case<br>• 18-M-0084)<br>• In 2025, a 3% reduction in annual electricity sales below forecasted sales (NY PSC Case 18-M-0084) |
| Washington | • All cost-effective programs mandate (Wash. Rev. Code § 19.285.040(1))<br>• Utilities must establish biennial targets based on their 10-year savings potential. Incremental annual savings have averaged 0.90% (Wa. Admin Code § 480-109)<br>• Utilities may propose performance incentives and face $50/MWh penalty for failure to meet their targets (Wash. Rev. Code § 19.285.060) |
| District of Columbia | • Cumulative savings of 4% from a 2014 baseline between 2017 and 2022 (DCSEU 2017 contract[39]) |

States, like California, have had a long history of investment in energy efficiency and thus have harvested the "low-hanging fruit." Accordingly, the efficiency targets from state-to-state are not easily comparable. Additionally, some states link their energy efficiency programs to their renewable portfolio standard, making comparisons difficult.[40] However, to ensure that the Commonwealth makes necessary, long-term investments in both renewable energy and energy efficiency businesses, this report recommends having separate and distinct energy efficiency targets and from the renewable portfolio standard mandates, as the VCEA is currently structured.

[39] https://doee.dc.gov/sites/default/files/dc/sites/ddoe/service_content/attachments/1%20Multi%20Year%20Contract%20with%20All%20Modifications.pdf

[40] Hawaii did so through 2015. *See* Haw. Rev. Stat. § 269-92(b)(2). Nevada will do so through 2025 but only has a non-binding zero-carbon target. *See* Nev. Rev. Stat. § 704.7821 (requiring each utility "to generate, acquire or save electricity from portfolio energy systems or efficiency measures"); Nev. Rev. Stat. Ann. § 704.__(Added by Acts 2019, ch. 3, § 8) (creating "a goal of achieving by 2050 an amount of energy production from zero carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service in this State").

## B. Efficient Buildings

Municipalities (cities, counties, and towns) and state governments have looked to modernizing their building codes to help conserve energy and reduce greenhouse gas emissions. In addition, existing building codes can be underenforced, meaning that there may be opportunities to drive efficiency savings simply through enforcement of standards already on the books.

California has long been a leader in establishing and enforcing efficient building requirements. In 2008, California's Energy Efficiency Strategic Plan set targets that all new residential construction would be net-zero energy by 2020 and new commercial buildings would be net-zero energy by 2030.[41] An interim update in 2011 added goals to retrofit half of existing commercial buildings to net-zero by 2030 and require major renovations of state buildings be net-zero energy.[42] The California Energy Commission is in the process of assessing the potential to reduce emissions from buildings by 40 percent below 1990 levels by 2030.[43] The 2019 California Building Code, which takes effect in 2020, brings the net-zero energy residential construction goal to fruition through a combination of efficiency requirements and a mandate to outfit all new construction with rooftop solar.[44] The Code also incorporates by reference California's appliance standards.[45] To leverage marketplace incentives, California now requires utilities to provide data that benchmarks energy usage relative to comparable buildings and requires sellers to disclose this information to potential buyers.[46] This benchmarking program applies to commercial buildings and large multi-family residential buildings.

In 2019, Washington enacted comprehensive legislation to direct investments in building efficiency, with the Washington Department of Commerce developing an energy performance standard and energy intensity targets for commercial buildings over 50,000 square feet.[47] There will be performance incentives for buildings to comply with new performance standards earlier than projected dates. The Washington law also requires utilities establish a system for building energy benchmarking, much like California's program.

Several other states have begun to prioritize building efficiency as part of their efforts to transition to zero-carbon electricity and reduce greenhouse gas emissions. Colorado recently required its counties to adopt one of the three most recent versions of the International Energy Conservation Code (IECC).[48] Similarly, Maine amended its statewide building code to reflect the most recent version of the IECC and created a stretch option for localities eager to exceed the state efficiency

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[41] *See* California Public Utilities Commission, *California Long Term Energy Efficiency Strategic Plan* (Sept. 24, 2008), https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5305. Though California uses the term "net-zero energy", it only requires that electricity consumption be less than on-site electricity production. Buildings that use gas or other fuels for heating still qualify as "net-zero energy."
[42] *See* California Public Utilities Commission, *California Long Term Energy Efficiency Strategic Plan: January 2011 Update* (Jan. 2011), https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5303
[43] *See* Cal. Pub. Res. Code. § 25403
[44] Cal. Code Regs. tit. 24 (2019)
[45] *Id.* § 110.1; *see* Cal. Code Regs. tit. 20, §§ 1601 *et seq.*
[46] *See* Cal. Pub. Res. Code § 25402.10; 20 Cal. Code Regs. §§ 1680-85
[47] *See* H.B. 1257, 66th Leg., 2019 Reg. Sess. (Wash. 2019)
[48] Colo. Rev. Stat. §30-28-201(3)

requirements.[49] New York's greenhouse gas emissions reduction scoping plan must incorporate a number of best-practices measures to improve efficiency in new and existing buildings.[50]

Public buildings are another potential source of significant energy savings. Almost all states, including all those with carbon-free energy targets, impose additional energy efficiency requirements on state agencies and government buildings. Although the total amount of energy savings may be small, a chief benefit of these programs is that changes can be made by executive action, allowing governors to act without waiting for legislation.

Programs fall into a several broad categories. At a minimum, states can monitor energy usage in government buildings.[51] Other programs use public data to benchmark energy usage at government facilities.[52] Other states also require public buildings to meet design or performance standards or both.[53] Direct benefits can be secured via mandates that state agencies reduce emissions by a certain percentage or kilowatt-hour target, which will often entail efficiency improvements on government property.[54] Finally, so-called "lead by example" initiatives may also require action by a state's public universities systems and other public schools.[55]

Other common programs to promote efficiency in buildings include financial incentives for private investments in efficiency, residential energy use disclosures, and appliance standards. Of the states with a zero-carbon energy target, a few—Hawaii, Maine, Massachusetts, and New York—require energy use disclosures for residential properties. Many of these states also have mandatory appliance standards.[56] However, state appliance standards run the risk of becoming obsolete in the face of changing federal regulations.[57] Both Massachusetts and New York are in the process of updating their appliance standards.[58]

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[49] *See* Me. Rev. Stat. tit. 10, § 9722

[50] The measures include "the beneficial electrification of water and space heating in buildings, establishing appliance efficiency standards, strengthening building energy codes, requiring annual building energy benchmarking, disclosing energy efficiency in home sales, and expanding the ability of state facilities to utilize performance contracting." N.Y. Envtl. Conserv. Law § 75-0103(13)(g)

[51] *See, e.g.,* Nev. Rev. Stat. § 701.218 (requiring tracking of energy use by buildings owned or occupied by a state agency)

[52] *See, e.g.,* Wash. Rev. Code § 19.27A.190 (establishing a benchmarking system and requiring underperforming buildings to make efficiency upgrades)

[53] *See, e.g.,* Mass. Exec. Order No. 484, 1077 Mass. Reg. 7 (May 4, 2007), https://www.mass.gov/files/documents/2016/08/od/eo484.pdf (requiring new construction and major modifications meet LEED Silver standards as well as perform at least 20% better than the Massachusetts building code)

[54] *See* Wash. Exec. Order 18-01 (Jan. 16, 2018), https://www.governor.wa.gov/sites/default/files/exe_order/18-01%20SEEP%20Executive%20Order%20%28tmp%29.pdf (mandating that energy-intensive state agencies reduce their emissions and consider the social cost of carbon in their actions)

[55] For example, Hawaii has set a goal that the University of Hawaii system net-zero energy by 2035. Haw. Rev. Stat. § 304A-119.

[56] *But see* H.P. 1245, 129th Leg., 2nd Reg. Sess. (Me. 2020) (seeking to establish appliance standards)

[57] *See* Mass. Gen. Laws Ch. 25B, § 1 *et seq.*; *see also* N.Y. Energy Law § 16-102 *et seq.* (Fourteen of nineteen standards preempted by a federal standard)

[58] *See* S.2478, 191st Gen. Ct., Reg. Sess. (Mass. 2020) (establishing updated appliance standards); *see also* N.Y. Energy Law § 16-106(4) (requiring annual reports on the status of appliance standards including reasons why standards have not been promulgated and estimates of potential energy savings from adopting new standards)

## VI. Non-Utility Distributed Generation

Non-utility, distributed generation allows homeowners, small businesses, and other community members to benefit directly from renewable energy power production. The most common forms of distributed generation are net metering, third-party power purchase agreements, and community solar programs, all of which leverage small-scale investments to accelerate the transition to a zero-carbon electricity grid.

Nearly 40 states have mandatory net metering policies, which allow a customer to receive credit for energy generated on their property. Customers may be credited at the retail rate, the utility's avoided cost, or some hybrid rate. The issue of determining the proper rate credit is a complex problem impacting all distributed generation programs. Nevada, for example, has attempted to resolve competing concerns with a tiered credit structure with rates that decrease for each 80-megawatt tranche of net metering capacity.[59]

Community solar (or shared solar)[60] refers to arrangements that allow customers to enjoy the advantages of solar energy without installing solar equipment on their own property. Community solar programs operate on a subscription model, allowing individuals, and sometimes small businesses, to pool their resources to invest in solar energy. Solar projects have significant upfront costs, which can effectively restrict renewable energy projects to those with access to capital. Nineteen states and Washington, D.C. have authorized community solar programs, and some states have multiple community solar programs.[61] Given the considerable number of variables in developing a program, the Interstate Renewable Energy Council has written model rules for community solar.[62]

## VII. Conclusion

Virginia is part of a growing, nationwide trend towards decarbonization. As stated at the outset of this chapter, twelve states, the District of Columbia, and Puerto Rico—collectively home to one-third of America's population—have now committed to building a 100% carbon-free electricity grid. Not surprisingly, we can learn from our sister states as we plan for the targets outlined in Executive Order 43. Every state employs an array of overlapping programs (*e.g.,* energy-efficiency targets, renewable portfolio standards, and long-term plans that account for the social cost of carbon). Every state also includes measures to assure accountability (*e.g.,* binding mandates in lieu of voluntary goals, reporting requirements). The ubiquity of these features—multi-faceted approaches with strong enforcement mechanisms—suggest that they will be essential for Virginia to meet its target of 30% renewable energy by 2030 and 100% carbon-free electricity by 2050.

[59] See Nev. Rev. Stat. § 704.7732

[60] Most programs allow other forms of renewable generation, but the vast majority of projects are solar.

[61] Jenny Heeter, et al., *Community Solar 101*, National Renewable Energy Laboratory (Jan. 2020), https://www.nrel.gov/docs/fy20osti/75982.pdf

[62] *See* Interstate Renewable Energy Council, *Model Rules for Shared Renewable Energy Programs* (June 2013), https://irecusa.org/publications/model-rules-for-shared-renewable-energy-programs/