Achieving Clean Electricity Generation at Least Cost to Ratepayers by 2045

DECEMBER 11, 2021

Prepared for the Virginia Department of Energy
by the Weldon Cooper Center for Public Service, University of Virginia

William Shobe and Anthony Artuso, University of Virginia
Maya Domeshek, Resources for the Future

VIRGINIA Energy

UNIVERSITY of VIRGINIA | Weldon Cooper Center for Public Service

LIST OF CONTRIBUTORS

Virginia Department of Energy (Virginia Energy)
Principle Investigator

Virginia Department of Environmental Quality (DEQ)

Resources for the Future (RFF)
Modeling Team

University of Virginia, Weldon Cooper Center for Public Service
Lead Report Author

Georgetown Climate Center

ACKNOWLEDGEMENTS

- DEQ: Christopher Bast, Thomas Ballou, Michael Dowd
- Dominion Energy
- Georgetown Climate Center: Franz Litz, James Bradbury
- Office of the Governor: Trieste Lockwood
- Office of the Secretary of Commerce and Trade: John Begala
- PJM
- RFF: Dallas Burtraw, Karen Palmer, Nicholas Roy
- Southern Environmental Law Center
- State Corporation Commission
- UVA: Will Olsen, Art Small
- Virginia Energy: Carrie Hearne, Al Christopher, Michael Skiffington, Erik Olson
- Numerous contributions from individuals and organizations
- Council on Environmental Justice and its Subcommittee on Just Transition and Infrastructure

EXECUTIVE SUMMARY

The Virginia Clean Economy Act (VCEA)[1] passed in 2020 requires the elimination of most CO_2 emissions from Virginia's electricity sector by 2050. The VCEA relies on four key pillars for accomplishing electricity sector decarbonization: (1) a clean energy standard, (2) joining the Regional Greenhouse Gas Initiative (RGGI) carbon pricing program, (3) a set of capacity targets for specific renewables technologies and (4) shutting down most CO_2 emitting power plants by 2045. The VCEA requests that the Secretary of Natural Resources and the Secretary of Commerce and Trade report to the General Assembly by January 1, 2022 recommendations "*to achieve 100 percent carbon-free electric energy generation by 2045 at least cost for ratepayers. Such report shall include 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.*"

To identify potential strategies for achieving least-cost decarbonization by 2045, the Virginia Department of Energy (Virginia Energy) and the Virginia Department of Environmental Quality (DEQ), with the support of the Georgetown Climate Center, led a research project to model possible strategies to achieve least-cost elimination of CO_2 emissions by 2045. A research team at Resources for the Future (RFF) in consultation with the Weldon Cooper Center for Public Service at the University of Virginia (Cooper Center) used RFF's electricity planning model, Haiku, to explore potential strategies for lowering the costs of meeting VCEA emissions targets. The Cooper Center had the primary responsibility for reporting the modeling results and evaluating other potentially important elements of a least-cost approach to decarbonizing Virginia's electricity sector.

The results of this investigation suggest a number of key strategies for lowering the costs of decarbonization. The modeling results are broadly consistent with the results of other studies of least-cost emissions reduction. Underlying many of the specific suggestions in this report are the principle that flexibility in technology, timing and geography all contribute to lower costs. Strategies that focus directly on reducing aggregate greenhouse gas emissions tend to have lower costs than strategies that specify particular techniques or locations for achieving those emissions. Elements of a flexible approach might include:

- Technology-neutral, competitive procurement of non-emitting generation
- Procurement of non-emitting generation from the PJM interconnection region
- Emphasizing market-based approaches such as the Regional Greenhouse Gas Initiative

[1] HB1526/SB851

MODELING STRATEGY AND KEY RESULTS

RFF's Haiku electricity model calculates the least-cost mix of electricity generation resources, given a set of input assumptions about electricity demand, generation costs and availability of renewable energy resources such as sun and wind. For this inquiry, a set of widely-used, standard assumptions from the U.S. Energy Information Administration and the National Renewable Energy Laboratory were used. The technology cost estimates are only for technologies that can be reasonably subjected to cost analysis in their current state of development. These estimates do not include technologies currently in the early stages of development. In particular, new nuclear, floating wind turbines and advanced geothermal technologies are not represented here. Should the cost of these technologies fall faster than expected, then a cost-effective strategy would include these in the mix of resources available for competitive procurement.

The Baseline Scenario reflects the current electricity sector stock of generation assets and the current policy environment, including the provisions of the VCEA such as the renewable portfolio standard, RGGI membership and the specific technology capacity goals for renewables and storage. Several results from the Baseline Scenario are true in the alternative scenarios as well:

- The four existing nuclear reactors are retained through the planning horizon
- Existing natural gas capacity is retained but with falling rates of utilization
- Utility-scale solar is the largest addition to generation capacity
- Between 2025 and 2035, the RPS is not binding (i.e. renewables investments exceed RPS requirements); offshore wind deployment substitutes for solar
- Electricity demand can be met with non-emitting resources by 2045

A series of policy scenarios were used to calculate the change in ratepayer costs likely to occur given a change in the VCEA pathway. Several possible cost-lowering adjustments were identified.

- Coal generation would retire for economic reasons by 2025
- Savings are available from the increased use of renewable energy credits from outside Virginia
- Investing in energy efficiency is cost effective, although improvements in evaluation and monitoring are necessary
- Competitive capacity procurement can result in significant savings over specific technology capacity targets

There are several possible cost-saving initiatives that were not easily incorporated into the electricity sector planning framework used in this study. In particular, enhanced grid planning and finance, more aggressive energy conservation efforts, distributed energy resources and demand management are all very fruitful areas for activities that have the potential to substantially lower the cost of decarbonization to ratepayers:

- There are potentially billions of dollars in savings from enhanced regional planning for grid modernization and finance
- The size of the energy efficiency resource may be very large but is unlikely to be be realized cost effectively without a significant investment in state agency capacity for advanced monitoring and evaluation
- Some recent studies suggest that distributed energy resources can be cost-effective notwithstanding their relatively high levelized cost of energy but further research is necessary
- Demand response, especially as EV penetrations rise, has a very large potential for cost-saving. Harvesting this resource requires a substantial investment in institutional innovation and creative tariff design

This modeling effort, along with many similar ones, indicates that eliminating CO_2 emissions from Virginia's electricity sector are technically achievable, but the approach taken to decarbonization can have a substantial effect on the cost of doing so. In the short run, much of the decarbonization effort centers around the buildout of utility-scale solar, our least expensive new energy resource, is central to a cost-effective decarbonization effort. In the medium to long term, the cost effectiveness of the energy transition will depend on maintaining a policy environment that promotes investment in least cost technologies as new clean energy and energy storage technologies emerge and the relative cost of currently available technologies continues to shift.

TABLE OF CONTENTS

INTRODUCTION

THE PURPOSE OF THIS STUDY

The Virginia Clean Economy Act (VCEA) passed in 2020 requires the elimination of most CO_2 emissions from Virginia's electricity sector by 2050.[2] In addition to its many other provisions, the VCEA provides:

> *That in developing a plan to reduce carbon dioxide emissions from covered units described in § 10.1-1308 of the Code of Virginia, as amended by this act, the Secretary of Natural Resources and the Secretary of Commerce and Trade, in consultation with the State Corporation Commission and the Council on Environmental Justice and appropriate stakeholders, shall report to the General Assembly by January 1, 2022, any recommendations on how to achieve 100 percent carbon-free electric energy generation by 2045 at least cost for ratepayers. Such report shall include 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…*

This report is in response to this request by (1) reporting to the General Assembly on how Virginia can achieve 100 percent carbon-free electricity by 2045 and (2) making 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."

Although it contains provisions addressing a broad array of policies, the VCEA primarily relies on four key pillars for accomplishing electricity sector decarbonization: (1) a renewable portfolio standard, (2) joining the Regional Greenhouse Gas Initiative (RGGI) carbon pricing program, (3) a set of capacity targets for specific renewables technologies and (4) shutting down CO_2 emitting power plants by 2045.

This study relies on modeling of Virginia's electricity sector and on other recent studies to examine how the Commonwealth might cost-effectively achieve by 2045 the goal of zero CO_2 emissions from the electricity sector. The available evidence suggests that increasing the flexibility of the approach to reducing CO_2 emissions can save Virginia ratepayers hundreds of millions of dollars per year by 2035 and beyond without relaxing the level of climate ambition. Replacing certain specific technology and geographic mandates with more a more flexible approach specifically targeting CO_2 emissions can substantially reduce the cost of achieving emission reduction goals. The results of the Virginia-specific modeling carried out for this study are in broad agreement with

[2] HB1526/SB851

other detailed studies of decarbonization strategies for the region and nation (Energy and Environmental Economics, 2020; Larson et al., 2020).

MODELING TEAM

Working on behalf of the Secretary of Commerce and Trade (SOCT) and Secretary of Natural and Historic Resources (SNHR), Virginia Department of Energy ("Virginia Energy") and Virginia Department of Environmental Quality ("DEQ") together ("the agencies") have led this research project. The agencies identified existing partnerships within the Commonwealth's network of public research institutions to support the agency's research and analysis on this technical mandate. The Georgetown Climate Center and the University of Virginia's Weldon Cooper Center for Public Service were selected as institutions where researchers have been actively engaged on the topics of decarbonization, electricity market transformation, regional carbon markets, economic impact analysis and greenhouse gas emission reductions, energy and environmental policy, among other topics.

In particular, the Georgetown Climate Center supported the modeling research through its partnership with Resources for the Future ("RFF"), a leading independent, global nonprofit research institution with deep expertise in environmental economics and energy policy. RFF uses the "Haiku" model to simulate regional electricity markets and interregional electricity trade in the continental United States. The model accounts for capacity planning, investment, and retirement over a multi-year horizon and for system operation over seasons of the year and times of day. The model is discussed in more detail below and throughout the report.

Throughout 2021, the modeling team worked to analyze the VCEA, build out the assumptions in the model to match the VCEA policy framework, and run a variety of modeling scenarios to determine how Virginia can achieve its 100 percent carbon free ("clean") electricity goals while keeping costs to ratepayers at a minimum.

PUBLIC COMMENT

In addition to direct analysis from the core modeling team, input was sought from key stakeholders, including but not limited to the following organizations: the State Corporation Commission ("SCC"), members of the Council on Environmental Justice and its subcommittee on Just Transition and Infrastructure, the impacted investor-owned utilities, Dominion Energy and Appalachian Power Company, the regional transmission operator, PJM, and the Southern Environmental Law Center ("SELC"). Further input was solicited from members of the public and key Virginia organizations. A list of all public commenters can be found in Appendix 1 of this report.[3]

[3] A full listing of the public comments is available from Virginia Energy

The agencies and the modeling team greatly appreciate the individuals and organizations who made contributions to this process, as it helped the team think through a variety of complex issues which are reflected in this report. While not all of the topics referenced in public comments have been addressed in this project and report, the agencies are committed to tracking these issues as the Commonwealth's energy sector shifts to a clean electricity system. Future reports may address certain elements that were raised in public comments, such as how certain income groups may experience benefits and/or burdens from the VCEA.

PLAN FOR THIS REPORT

Section 2 briefly reviews the recent emission history of Virginia's electricity sector. Section 3 discusses some general principles for reducing decarbonization costs, principles gleaned from recent studies at the regional and national level. Section 4 describes in detail the specific modeling for this study of cost-reducing strategies for Virginia. Section 5 and Section 6 discuss some other components of a least-cost approach. Section 7 concludes.

A QUICK LOOK AT VIRGINIA'S ELECTRICITY SECTOR

The electricity sector in Virginia is changing rapidly. Recent emission trends are dominated by three factors, declining imports, the rapid substitution of natural gas for coal as a primary energy source and, more recently, the increasing penetration of solar generation. Electricity sector emissions in Virginia have fallen by more than 25% since their high in the year 2000, even as generation rose by 33% during the same period. (Through 2019, this decrease in emissions was primarily due to increasing substitution of natural gas for coal.) Because of the 50% decrease in imports, Virginia's own emissions of CO_2 have been relatively flat since 2015, as in-state generation has substituted for imports. The CO_2 emissions per unit of electricity produced has fallen by more than half since its high in 2001 and is expected to continue to improve in the future.

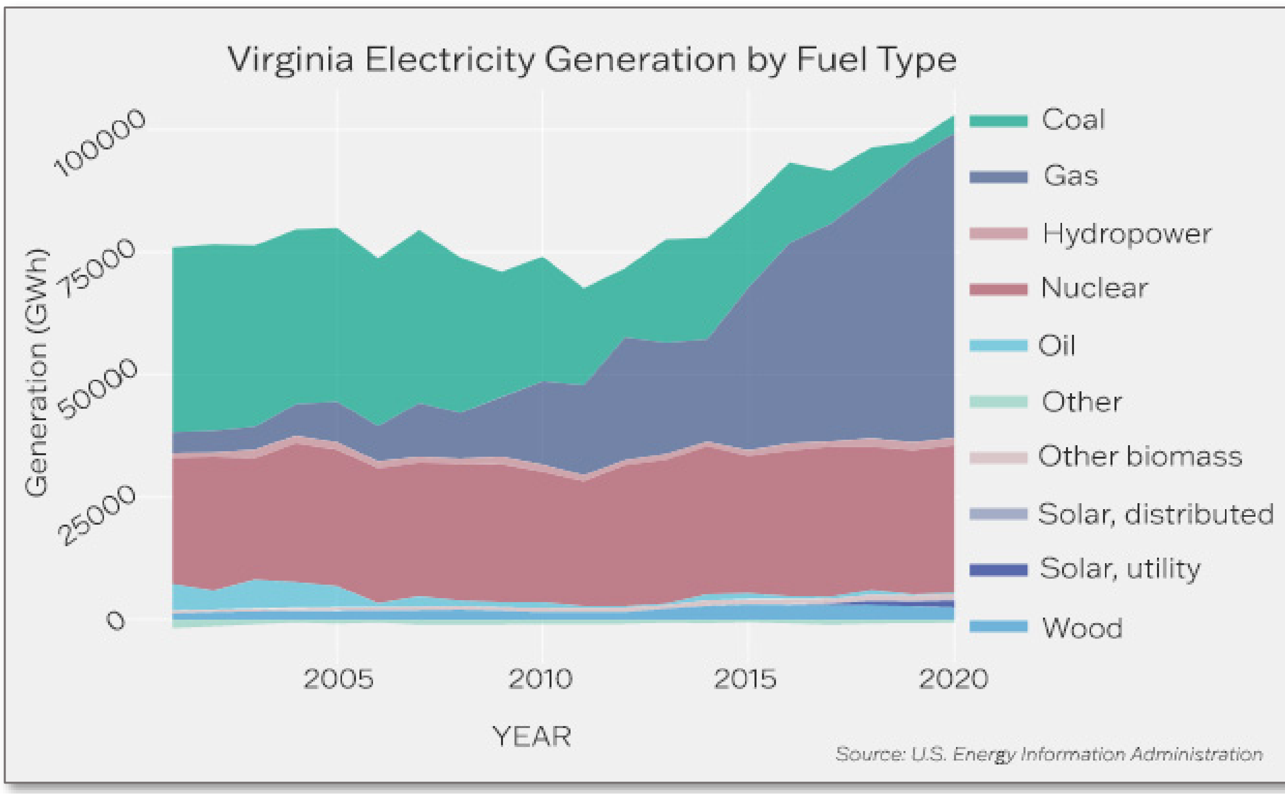


Figure 1: Virginia Electricity Generation By Fuel Type: 2001-2020

Recently, as the transition away from coal-fired generation accelerated, an increasing share of renewable energy, solar generation in particular, has begun to displace fossil-fired generation. In the first eight months of 2021, utility-scale and distributed solar generated the same amount of electricity in Virginia as coal (3.8%). Utility-scale solar will account for more than 3% of electricity generation in 2021, double that of 2020 and up from zero in 2015. Virginia currently has more than

2 gigawatts (GW) of utility-scale solar capacity in operation, with 3 GW in advanced stages of development. In 2022, solar will be the third largest source of electricity in Virginia after natural gas and nuclear.

Demand for electricity has grown relatively slowly since 2007 due to moderating population growth and improved energy efficiency in the residential and commercial sectors. Sales of electricity to data centers has been the only growing sector of electricity sales in recent years, and these sales can be expected to continue to grow for the next several years. Increasing sales for electric vehicles (EVs) should begin have an effect on growth rates even as early as 2022.[4] Even with the recent growth of data center sales, the electricity intensity of economic activity in Virginia has continued to fall. A dollar of gross state product now requires half as much electricity as it did in the year 2000.

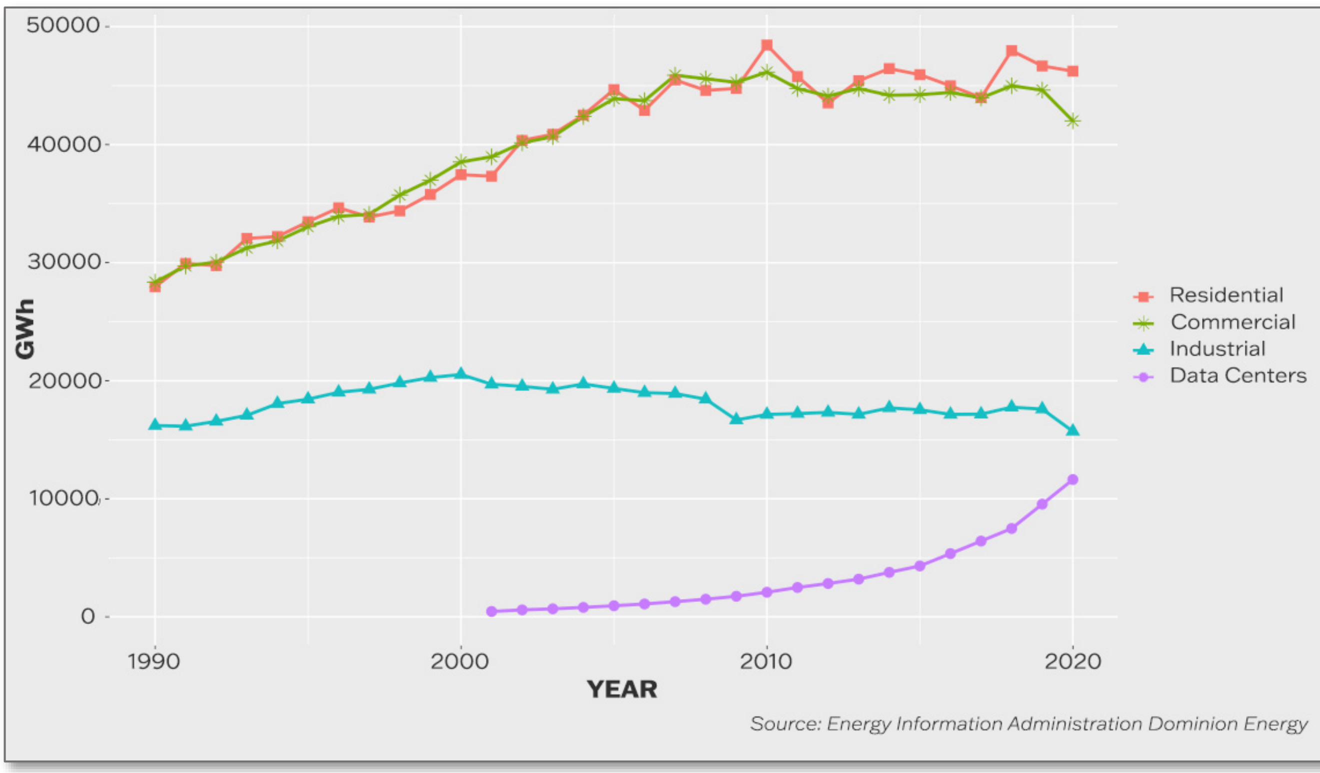


Figure 2: Annual Virginia Electricity Sales by End Use

4 For a detailed forecast of future electricity demand in Virginia, see (Shobe 2021).

MODELING METHODOLOGY AND ASSUMPTIONS

Virginia's electricity sector is integrated into a much larger regional grid. Dispatch of generation resources and balancing supply and demand are managed centrally by the PJM independent system operator (ISO). Decisions about Virginia's energy future must account for the interconnectedness with the rest of PJM and with neighboring states and accommodate the variety of policy perspectives across the region.

The Haiku electricity model, used in this study, is a long-term planning model of the US electricity sector. The model calculates the least-cost way to meet Virginia and US electricity demand over the period from 2019-2045 given the existing power plants in each state, planned additions and subtractions from the existing fleet of power plants, the costs to build new facilities, the cost of running such facilities, and the availability of sun and wind renewable resources. The model also includes existing environmental regulations at the federal and state level. Each state is represented as a separate node with transmission between states and individual power plants grouped into categories by fuel and technology. The model calculates the generation mix, emissions, and power plant capacity for each state and year that will minimize total cost. It also provides information about resource cost—the cost to run the electricity grid—including fuel costs, capital costs, operations and maintenance costs, and costs to import and export electricity.

The model includes information about existing and planned powerplant capacity from the S&P Global database. It chooses to build new model plants or add or remove capacity from existing model fossil plants plants based on costs from the Energy Information Administration's Annual Energy Outlook 2021 (AEO2021) reference case, and for renewable plants based on costs from the National Renewable Energy Lab's Annual Technology Baseline 2020 (NREL ATB 2020). Demand is fixed to the level projected in the Annual Energy Outlook 2021 reference case, subject to the investments in energy efficiency that are explicitly part of this study. The load profile is based on the US Energy Information Agency's form 930 for historical hourly demand. This hourly demand is grouped into 24 representative hours (for three seasons and eight times of day) and the model represents system operations within each year for each of those hours. Solar and wind availability are represented at the state-level for the same time blocks used to represent system operations. The model includes PJM reserve capacity requirements and constrains inter-state transmission capability to the maximum observed.

Haiku does not represent emerging technologies that have yet to reach commercial scale such as carbon capture and storage or synthetic fuels, hydrogen and ammonia, nor does it permit economic investments in new nuclear units, new hydro units, or new pumped storage units, although existing and planned new facilities of those types are included in the model. It does allow economic investment in commercially demonstrated technologies including 4- hour batteries, solar, and on and offshore wind. The technology mix chosen by the model thus reflects those most readily available in the next fifteen years without further regulatory developments or dramatic shifts in technology.

The Haiku model does not include the cost of expanding transmission capacity. Transmission modernization planning will be discussed in Section 6.

Haiku, like other capacity planning models, chooses the cost-minimizing mix of technologies for the U.S., given set of input assumptions. Thus, given any starting assumptions about inputs, the model is designed to choose the capital investments and operating plan that minimize the cost of building and operating the electricity sector. Since cost-minimization is built into the modeling approach, differences in costs among the various scenarios arise due to the different assumptions made about model inputs and policy assumptions.

Because of its high current costs relative to utility-scale solar, the model will not choose to rely on distributed solar for more than a marginal contribution to the electricity supply. The potential benefits of greater reliance on distributed solar that are not fully captured in the model are discussed in more detail below.

The Haiku model focuses on generation planning and does not address energy efficiency investments and demand response load shifting strategies. These topics are addressed separately in Section 6.

This report did not include explicit modeling of grid modernization and regional transmission planning. The changes that are underway in electricity generation and use are, in turn, forcing a rethinking of strategies for planning, building, and managing the transmission and distribution infrastructure (Fox-Penner, 2020). Even in the absence of the need to decarbonize the economy, the basic design and operation of the grid will require substantial changes. Coordinating these essential grid modernization efforts with the transition of the electricity supply to one that is more diverse and distributed will shift grid design away from one-way electricity transport to one of resource and consumer connectedness. In the future, electricity generation, demand response and storage may take place anywhere. This connectedness will ultimately allow us to treat even household consumer devices as providers of grid services.

Long-run uncertainty about the economics of emerging technologies does not need to delay action today. Virtually every long-range energy plan, whether it requires full decarbonization or not, starts with much the same short-run plan for generation capacity expansion. The least-cost path forward, regardless of the policy environment, involves emphasizing the construction of utility-scale solar and on-shore wind generation. In the longer-run there will be new options to consider, but Virginia’s short-run generation choices do not appear likely to lock us in to a given long-run path.

State policy makers have time to re-evaluate changing options and make mid-course corrections as needed, once some of the uncertainty over future technologies and projected costs of currently available technologies is resolved.

Given the great uncertainty over the final five years of the policy horizon, that is 2041 – 2045, the cost estimates become more speculative, relying on predictions of how technologies will develop more than two decades in the future. Actual decarbonization pathways will involve deployment of technologies that are not yet commercially viable. *This report only considers currently available technologies for both generation and storage*. It does not include carbon capture and storage, long-term storage, synthetic fuels, geothermal power or small modular nuclear reactors. Th exclusion of these technologies makes the out-year cost estimates higher than what is likely to occur, but has the advantage of demonstrating the technical feasibility of a zero carbon electricity system even without significant technological breakthroughs. This methodology is an appropriately conservative approach, demonstrating feasibility under current, gradually improving technology rather than starting with more optimistic technology assumptions.

DISCUSSION OF BASELINE ASSUMPTIONS

Table 1 shows the key assumptions used for the Baseline Scenario. The national AEO2021 demand forecast is down-scaled to Virginia based on historical share of regional demand minus the energy savings from the energy efficiency resource standard (EERS). Electricity consumption grows at about one percent per year. (It should be noted that EV penetration is very slow in the AEO2021 Reference Case, amounting to only about one percent of electricity consumption by 2040.) The AEO2021 Reference Case is comparable to the PJM electricity demand forecast for the DOM Zone. The choice of AEO2021 over the PJM forecast does not make an appreciable difference in the analysis. Using the AEO2021 provides a consistent national forecast that can be used for all of the regions in the model.

The ATB2020 cost estimates for offshore wind includes costs for laying underwater cable. The cost forecasts in the ATB2020 are illustrated in Figure 1, showing expected levelized cost of energy (LCOE).[5] A cost-minimizing planning model will deploy technologies approximately according to the cost estimates illustrated in Figure 1, but several observations are in order:

- An important implicit assumption in the ATB2020 estimates is that the costs of deployment of a given technology for Virginia (and other places) do not change based on the amount of deployments that have already occurred. Under the assumptions of the ATB2020, the cost of deployment of solar and wind does not vary as the scale of deployment increases. This assumption may not hold in practice as solar and wind deployment expand, since the land most appropriate for solar or onshore wind deployment may be subject to increasing costs

[5] The levelized cost of energy (LCOE) is the average net present value of the cost of generation over the expected lifetime of the plant.

as the scale of deployment increases. Changes in costs due to changes in the relative scarcity of appropriate land resources could be an important factor in the later years of the policy horizon, past 2035, and could change the relative cost-effectiveness of different, non-emitting generation technologies. The magnitude of this effect depends on other policy choices such as grid planning and deployment.

- The technology cost measure does not take into account any other policy priorities that might lead policy makers to choose a more expensive technology over a cheaper one. This approach is consistent with the mandate for this study, which focuses on minimizing costs to ratepayers.
- The ATB2020 estimates do not include technologies currently in the early stages of development. In particular, new nuclear and advanced geothermal technologies are not represented here. Even if they were to achieve some level of deployment, they would only begin to become competitive with other sources in the last few years of the policy horizon.

Figure 3: Estimated Levelized Cost of Energy for Various Technologies

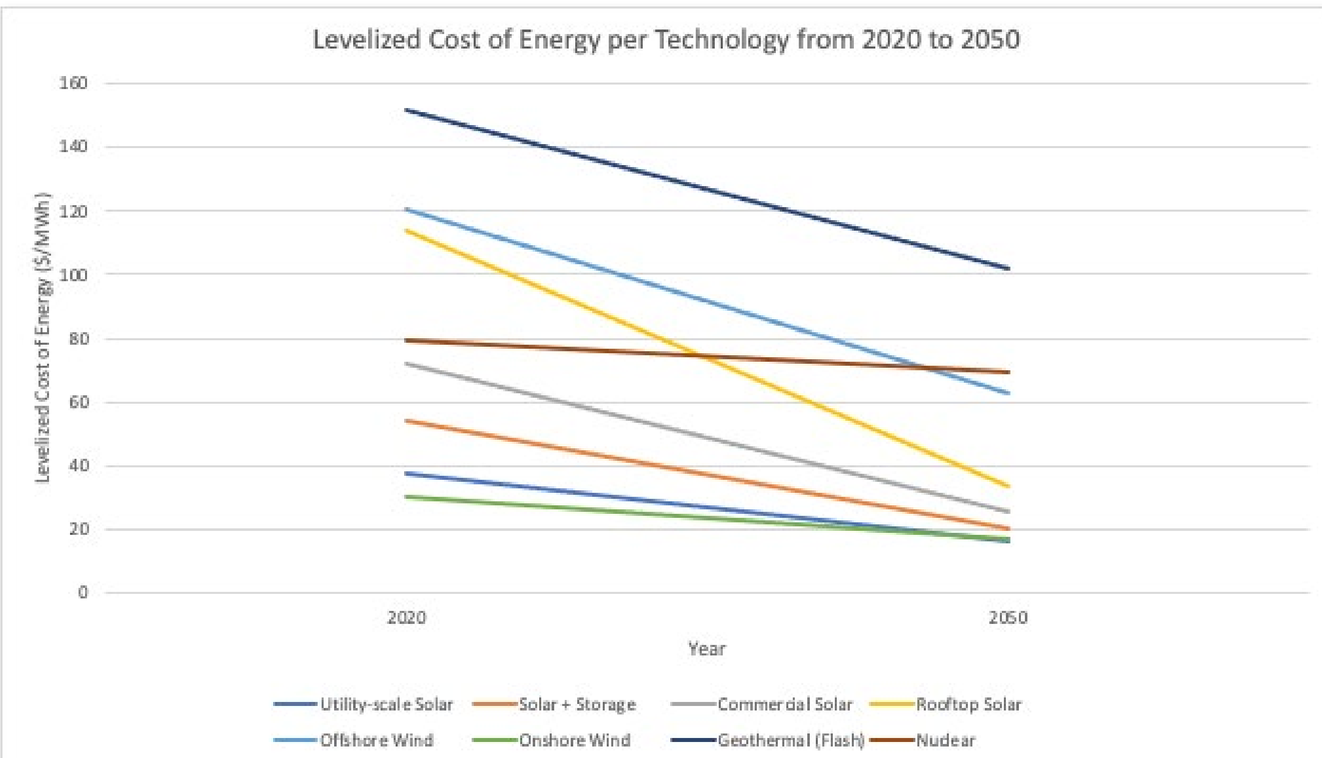


Table 1: Levelized Cost of Energy ($/MWh) 2020 – 2050 (NREL ATB 2020)

	2020	2050
Utility-scale Solar	37.9	16.3
Solar + Storage	54	20.4
Commercial Solar	72.3	25.8
Rooftop Solar	114	33.8
Offshore Wind	120.8	62.5
Onshore Wind	30.4	17.2
Geothermal (Flash)	151.5	102
Nuclear	79.6	69.6

Table 2: Important Reference Case Assumptions

Category	Source/Approach for Reference Case Assumptions
Haiku Reporting Years	Reporting years for the model: 2021, 2022, 2023, 2024, 2025, 2027, 2030, 2033, 2035, 2036, 2040, 2045
Demand - Load and Peak Growth	Demand from Energy Information Administration 2021 Annual Energy Outlook (AEO2021)
Gas Prices	Annual Energy Outlook 2021 Reference Case gas prices
Build Costs - Renewables	National Renewable Energy Laboratory 2020 ATB mid-cost scenario for renewable overnight capital costs
Minimum Generation	Minimum Generation for some technologies such as Combined Heat and Power and Conventional Hydro
Maximum Generation	VA pumped storage has seasonal maximum generation based on historical generation
Firm Capacity Changes	Latest information from S&P Global Market Intelligence VA - Any additional capacity changes not accounted for in S&P Global
Nuclear Lifetime	80 years, or as planned by owners
Renewable Portfolio Standards (RPS)	State-level RPS for all states with statutory RPSs VA: 100% by 2050. Remove nuclear and data centers from denominator. Allow 25% of RECs to come from outside of VA after 2025. Alternative Compliance Payment of $45
Solar & Onshore Wind Procurement	From the VCEA: VA: 16,100 MW of combined solar and onshore wind 2036
Offshore Wind/Storage Requirements	Minimum based on input from the states and expectations based on state policies/announcements NY: 9,000 MW Offshore Wind by 2035 / 3,000 MW Storage by 2030 MA: 3,200 MW Offshore Wind by 2030/ 1,000 MW Storage by 2025 CT: 2,000 MW Offshore Wind by 2030 RI: 400 MW Offshore Wind by 2030 MD: 1,568 MW Offshore Wind by 2030 NJ: 4,000 MW Offshore Wind by 2030 / 2,000 MW Storage by 2030 VA: 2,600 MW Offshore Wind by 2026 / 3,100 MW Storage by 2035
RGGI Program Assumptions	11 Current RGGI States + PA. Emissions cap declines 3% per year of 2020 levels (NJ 2021, VA 2021, PA 2022)
EE Assumptions	VCEA EERS extended at 1% per year from 2026 removed from AEO demand projections

Except as noted, most existing generation assets remain in place through the policy horizon. In all scenarios modeled, the four in-service nuclear reactors are relicensed by the Nuclear Regulatory Commission for operation beyond 2050. All coal plants close by the end of 2024, except for the Virginia City Hybrid Energy Center (VCHEC) in Wise.[6] This plant remains in service through 2045 as specified in Dominion Energy's 2020 Integrated Resource Plan, operating at a very low capacity factor due to its very low cost-effectiveness. All existing natural gas boilers not currently scheduled for retirement are retained through the policy period. Planned builds, such as the Chickahominy Gas plant, are assumed to be in operation by 2025.[7]

Four fossil plants, Doswell Energy Center, Panda Stonewall Power Project, Marsh Run Generation Facility and Louisa Generation Facility are not directly required to close by the provisions of the VCEA. Over the period covered by the modeling effort, these plants will become increasingly uncompetitive with the expansion of zero marginal cost generation from wind and solar facilities and the declining costs of energy storage technologies. By 2045 their utilization will fall to low levels partly due to competition with expanding renewables but also due to the rising price of emitting CO_2 under the RGGI cap. Since the VCEA requires that the Virginia's budget under the RGGI cap reach zero in 2049, CO_2 emitting facilities will become increasingly uneconomic. As a result, these plants are assumed to close by the end of 2045.

The mandate for this study requires that the electricity sector achieve zero emissions by 2045. This requirement achieves zero emissions five years earlier than the VCEA RPS and RGGI provisions. The VCEA requires the retirement of all emitting facilities by the end of 2045, so the model forces all remaining generation facilities with CO2 emissions to retire on January 1st 2046.

It is assumed that the transmission system has adequate capacity to accommodate the generation resources used to meet consumer demand. Although a detailed analysis of transmission and distribution adequacy was not a focus of this study, it is a topic that warrants substantial attention in the near term and is discussed in Section 6. Grid modernization is becoming a pressing issue as the mix of low-cost generation resources changes and as the cost advantages of grid modernization become more apparent.

While the current RGGI memorandum of understanding only specifies cap reductions through 2030, it is generally expected that cap reductions will continue after 2030, so the base-case

[6] The Clover Power Station, jointly owned by Dominion Energy and the Old Dominion Electric Cooperative, is slated to close in Dominion Energy's latest integrated resource plan and so is assumed to close. In 2021, through the month of September, the Clover Power Station operated at only 17% of its rated capacity.
[7] A natural gas power plant slated for Charles City was cancelled during this modeling effort. The inclusion of the Charles City plant does not make an appreciable difference in the model outcome. The main effect of the additional plant is to reduce the operating capacity of the other natural gas plants in Virginia.

assumption regarding RGGI implementation is a continued reduction of the regional cap by three percent of the 2020 cap level per year through the policy horizon.[8]

<u>Recent and pending federal legislation:</u> The recently passed federal infrastructure funding bill contains several billion dollars for grid modernization, CO_2 capture technologies, CO_2 transport, clean hydrogen and subsidies for continued operation of existing nuclear plants. The likely effects of these changes in federal policies are not reflected in the model assumptions.

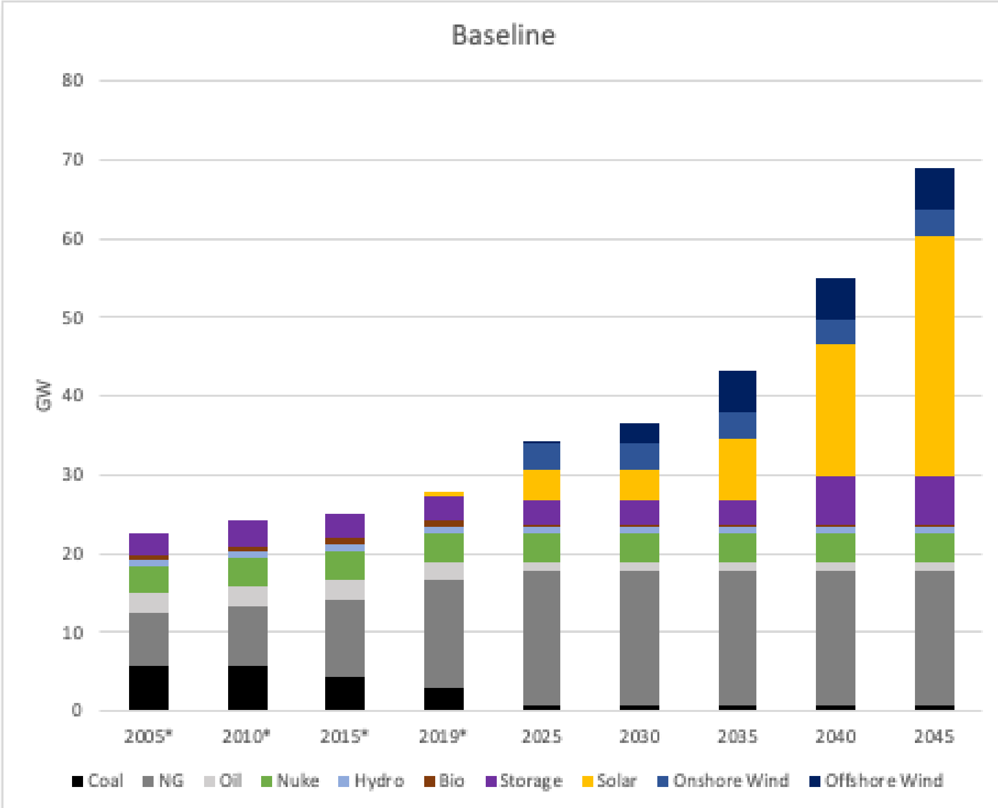
[8] The VCEA specifies that any emission cap reach zero by 2049. This provision is not reflected in the model scenarios. Doing so would not appreciably change the results, since other emission constraints are more binding than the 2049 cap provision.

MODEL RESULTS

THE BASELINE SCENARIO

The Baseline Scenario results are illustrated in Figures 4, 5 and 6. Figure 4 depicts the capacity mix expected under the VCEA. All coal except the VCHEC retires by 2025. Legacy natural gas and nuclear capacity are retained through the policy period. The additions to capacity are all renewable resources and storage. Utility-scale solar is the preferred new resource due to its low capital and operating costs, reaching 30GW installed by 2045. Figure 5 shows annual generation by resource type. The expanding supply of renewables gradually displaces natural gas generation. Interestingly, there is no systematic increase in the level of imports due to the relatively aggressive addition of offshore wind and solar. The existing nuclear capacity has an outsized share of generation due to its high capacity factor.

Emissions are shown in Figure 6. They decline steadily until dropping to zero on the first day of 2046, since the modeling constrains all fossil generation to shut down on the last day of 2045.



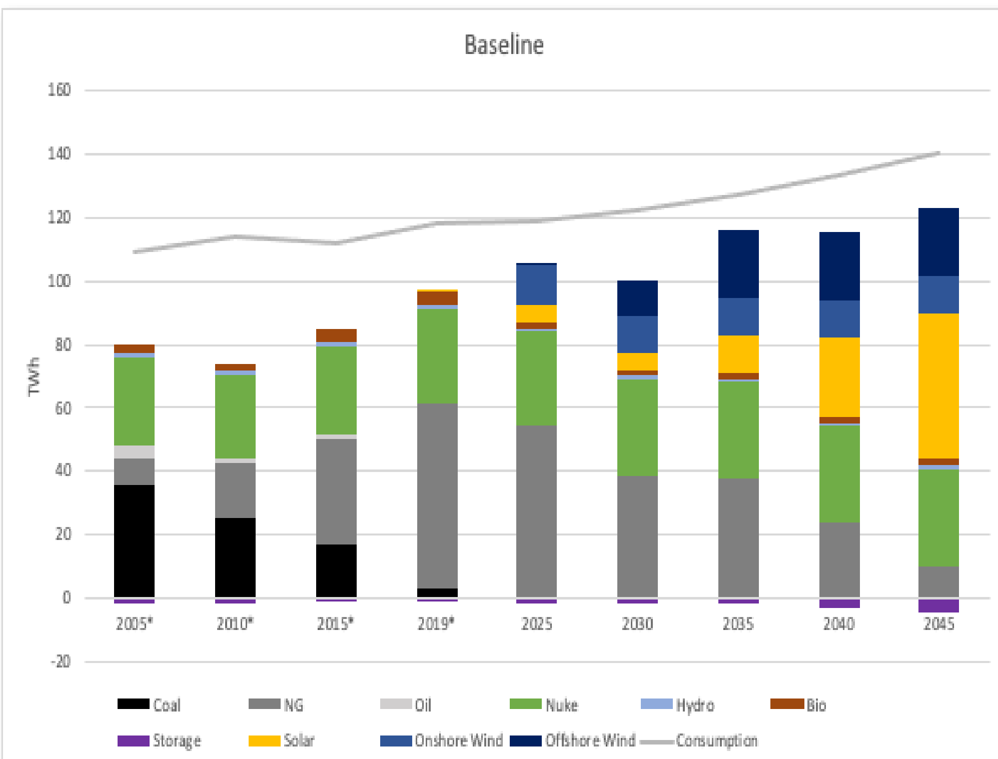


Figure 4: Baseline Scenario Capacity (GW) and Generation (TWh)

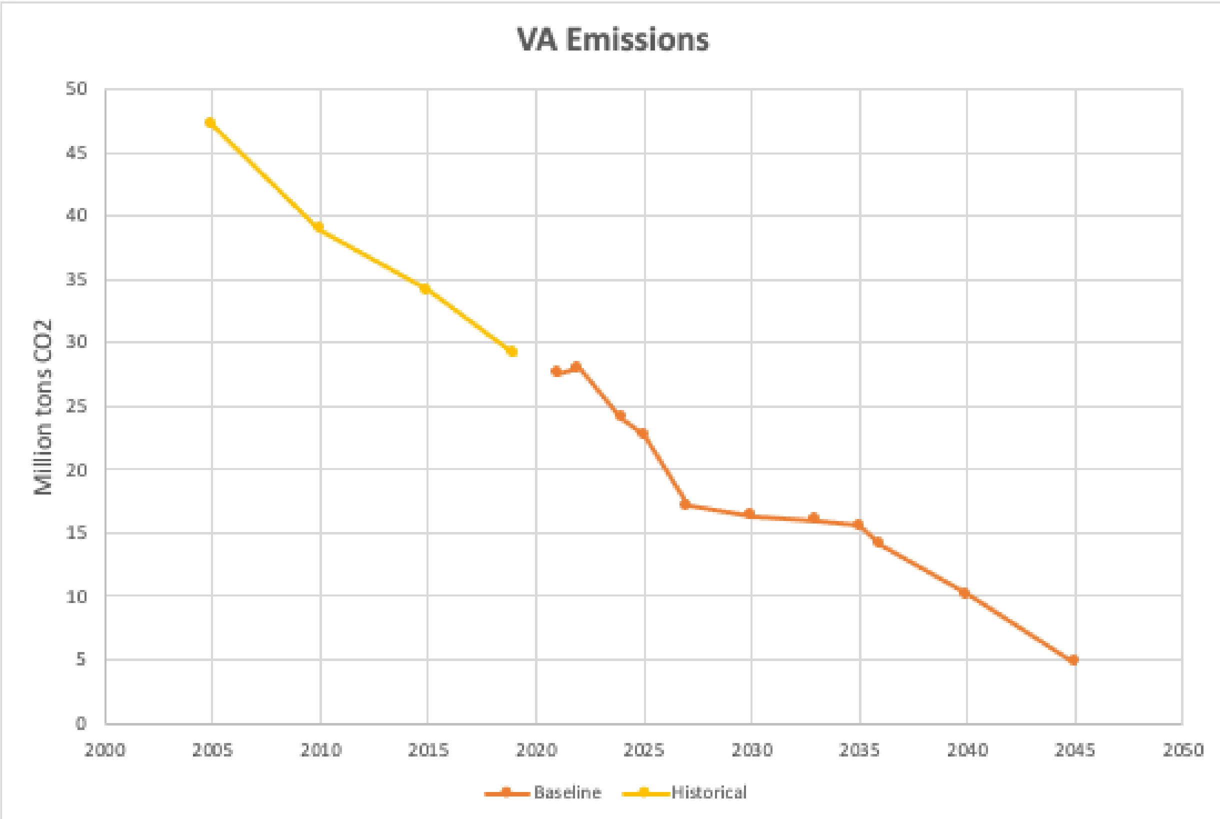


Figure 5: Virginia CO_2 Emissions - Actuals and Predicted

The Baseline Scenario results illustrate several important points:

1. No additional fossil capacity is built to meet expected consumption, including seasonal variation in supply and demand. (Since the model used here does not evaluate the potential for local transmission constraints, it does not address the possible need for local additions to generation needed to address geographically localized supply constraints.)
2. Nuclear generation remains constant through the policy horizon. New nuclear technologies were not considered in the model scenarios, since the technology is currently considered too speculative for inclusion. Given the recent increase in federal funding for advanced nuclear research and deployment, the question of advanced nuclear generation availability should be revisited if the technology advances faster than current expectations suggest.
3. The RPS is not a binding upper-bound constraint on emissions (fossil generation) during the period from 2025 to 2035. The aggressive capacity targets explicitly identified in the VCEA for solar and offshore wind (combined with assumed slow demand growth) keep the non-emitting generation portfolio above the minimum RPS levels during those years. In the years up to 2025, whether the RPS is binding (i.e. sets the pace for use of renewables) depends on the availability of renewable energy credits (RECS) from the other states in PJM.

A high availability of RECS from PJM would result a in greater use of renewables than required by the RPS, and lower costs, during some early years.

4. All new capacity, aside from two natural gas plants currently in the permitting process, is renewables and storage.[9] Solar and onshore wind are the cheapest incremental generation technologies. The offshore wind is built by the model because it is a capacity target specified in the VCEA. The additional storage deployed before 2040 is also due to VCEA targets, rather than least-cost supply and demand balancing.
5. Wind and solar are, in the early years, largely substitutes for each other. The onshore wind capacity chosen by the cost minimization algorithm may appear large given the current low levels of planned onshore wind capacity for Virginia. At the time of this writing, the PJM interconnection queue only shows 400 MW of wind for Virginia. Were this wind not available, the model would substitute additional solar generation at approximately the same levelized cost. The first 2.7 GW of offshore wind substitutes for deployment of additional solar, since the RPS is being satisfied by the target offshore wind generation.
6. Existing natural gas generation capacity is retained through the policy horizon but operates at declining capacity factors. The role of legacy gas plants shifts from primarily baseload, bulk power to a role of seasonal supply and load following to compensate for the increasing penetration of variable renewable resources.
7. By 2040, less than 20% of generation is from legacy fossil fuel plants. Because solar, wind and nuclear have very low marginal costs, these resources, once built will tend to reduce the level of imports of electricity.
8. Emissions fall rapidly at first due to the RPS and the renewables capacity targets in the VCEA. Later on, after 2035, the RPS (and the RGGI cap) push emissions down, but on a path that reaches zero by 2050 under the terms of the VCEA. In the base case, emissions stay on this path until the end of 2045, when they drop to zero.
9. Given the standard forecast for natural gas prices, the addition of natural gas capacity between now and 2025 does not appear to increase net natural gas generation in Virginia. In the base case, natural gas generation falls between 2019 and 2025 even with the addition of the Charles City and Chickahominy plants. The addition of these plants substitutes for other natural gas generation in the state.
10. In broad outline, these results are quite similar to those of other modeling exercises on decarbonizing Virginia's economy(Cole et al., 2020; Energy and Environmental Economics, 2020).

[9] A natural gas power plant slated for Charles City was cancelled during this modeling effort. The inclusion of the Charles City plant does not make an appreciable difference in the model outcome. The main effect of the additional plant is to reduce the operating capacity of the other natural gas plants in Virginia.

SENSITIVITY SCENARIOS

The modeling strategy for this report starts with the definition of the base case, the Baseline Scenario. The main assumptions used to define this case were discussed in the previous section. This section reports on the Baseline Scenario results along with three sensitivity cases that investigate how the results change in response to different assumptions regarding renewable technology costs, natural gas prices and the rate of growth in electricity demand. Following the sensitivity cases are a set of policy scenarios that investigate how different policy choices will affect ratepayer costs.

Scenario label	Description
LowNG	Sensitivity with low NG prices
HighRECost	Sensitivity with high renewable cost. (how high)
HighCons	Sensitivity with high data center and EV growth

1) Low natural gas prices [LowNG]

The Low Natural Gas Price scenario assumes that natural gas prices follow the AEO2021 High Oil and Gas Resource Case. In this case, NG price is about 10 percent below that in the base case. Virginia emissions increase in this case as increased gas generation in Virginia substitutes for coal generation in the rest of PJM. Total emissions in PJM fall due to increased substitution of gas for coal. Interestingly, the Virginia RPS is not binding during some years due to the aggressive renewables capacity targets. In the absence of the capacity targets, the RPS would be binding and would still prevent the expansion of natural gas capacity. The combination of the RPS, the declining RGGI cap and the capacity targets for solar and wind in the VCEA are sufficient to prevent the building of any new NG generation even in a scenario favorable to new NG capacity. The low NG prices specified in the AEO2021 high resource availability case save Virginia ratepayers about $500 million per year in fuel costs and avoided imports.

2) High renewables costs [HighRECost]

This sensitivity test uses the NREL ATB2020 conservative (high capital costs) case. The results may appear somewhat unexpected at first. The main difference between this case and the Baseline is an **increase** in solar capacity in Virginia during the years prior to 2035. This counter-intuitive result arises due to the federal investment tax credit for solar. The tax credit is determined as a percent of capital costs, consequently a given increase capital costs of solar has a smaller impact on ratepayers than the same percentage increase in capital costs of other electric generation technologies. Nevertheless, higher renewables costs in this scenario do increase ratepayer costs by around $100 million per year by 2040. Increased federal support for research and development can have substantial benefits for Virginia's economy by reducing the cost of energy services.

3) The high electricity demand case [HighCons]

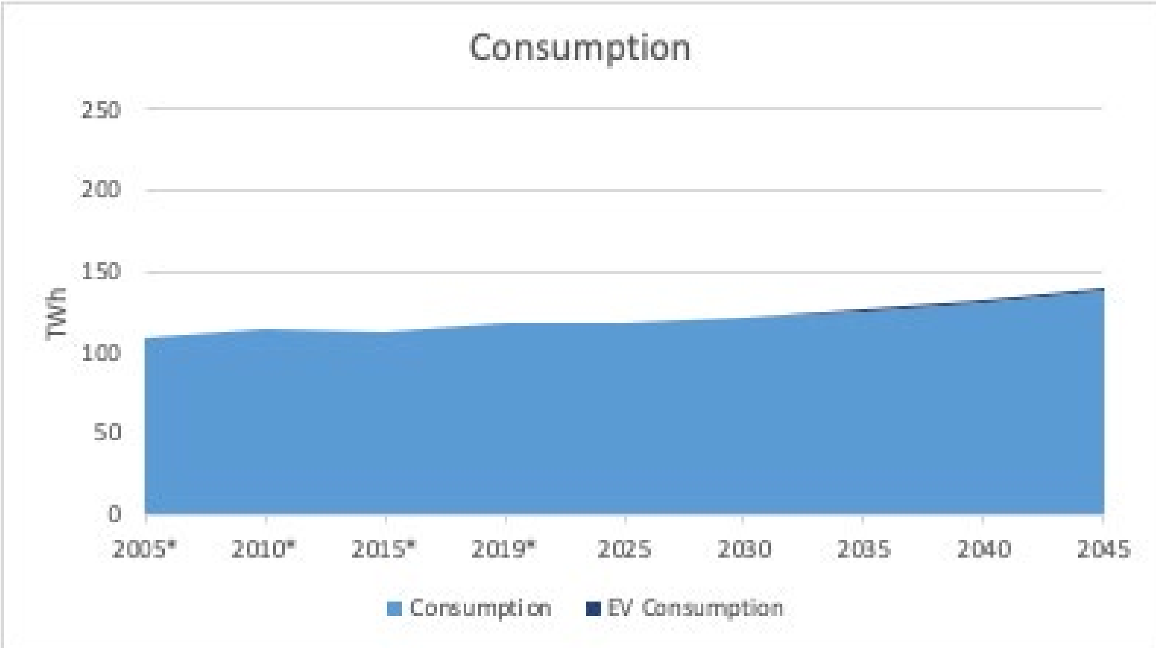
The AEO2021 forecast of electricity demand growth has electricity sales growing slowly from the current 118 terawatt-hours (TWh) to 140 TWh by 2045. Due to the slow forecast penetration of EVs assumed in the AEO2021 forecast, only 2.5 TWh are consumed by EVs in 2045. There are at least two reasons to believe that electricity demand growth in Virginia will outpace the growth assumed in AEO2021. First, current forecasts of EV sales by private sector analysts and by the automakers themselves anticipate a considerably faster transition to electric vehicles. Second, growth in electricity consumption by data centers has continued to grow at an increasing rate, at least through the end of 2020, the most recent data available.

To better understand the likely effect of these two factors on future electricity consumption, UVA's Weldon Cooper Center for Public Service developed an independent electricity sales forecast for Virginia for 2020 through 2050 (Shobe, 2021). The Cooper Center analysis found that electricity demand has not been growing appreciably in any sector: residential, commercial or industrial, with one exception: data centers. The Cooper Center's forecast separates Dominion Energy data center sales from other commercial sales and uses monthly data center electricity consumption through 2020 to estimate future sales. Accounting for likely future growth of data center demand results in a considerably higher forecast of electricity demand compared to the AEO2021 forecast, as much as 40% higher.

The Cooper Center forecast report also developed two scenarios for the stock of EVs between now and 2050. Both of these scenarios are intended to reflect the rapidly increasing private estimates of the likely turnover of the vehicle fleet. The scenarios describe paths to 75% and 98% of the total light duty vehicle stock by 2050. These scenarios were designed to estimate the upper range of light duty EV electricity use by 2050. EV electricity demand could increase overall demand by nearly 20% in 2050, compared to the standard demand forecast. No estimates were made concerning heavy duty transport, since electrification of this sector is still highly speculative.

The combined effect of increased data center and EV consumption results in total electricity sales of almost 210 TWh by 2045. Data center sales amount to over 80 TWh in this high sales forecast. EV sales amount to 23 TWh. Statewide CO_2 emissions fall considerably in this case because the vehicle fleet converts from internal combustion engines, which generate, 602 grams of CO_2 per mile, to electricity generated primarily by non-emitting technologies. Based on the Cooper Center high-vehicle penetration scenario, economy-wide CO_2 emissions actually fall by 45 million metric tons per year by 2050, or by much more than the current emissions of the entire electricity sector, due to the substitution of EVs for internal combustion engines in light-duty transport.

There are also considerable cost savings from converting the vehicle fleet to EVs. As reported below, consumers/ratepayers save money on fuel and repair costs. And each electric car is a rolling battery. Consequently, the cumulative electricity storage capacity will be much higher than that measured by storage-only battery installations. New vehicle-to-grid technologies are expected to enable grid utilization of EV battery storage, facilitate renewables integration and produce savings for ratepayers, but this technology was not included in the modeling, since its effects are still quite speculative.



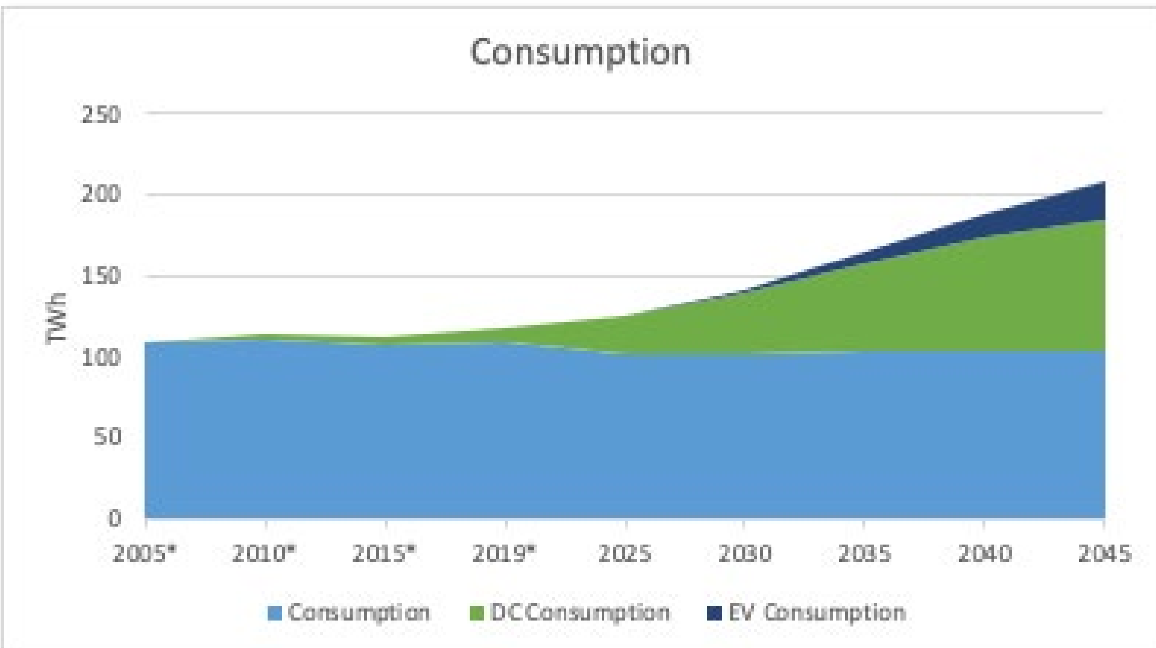
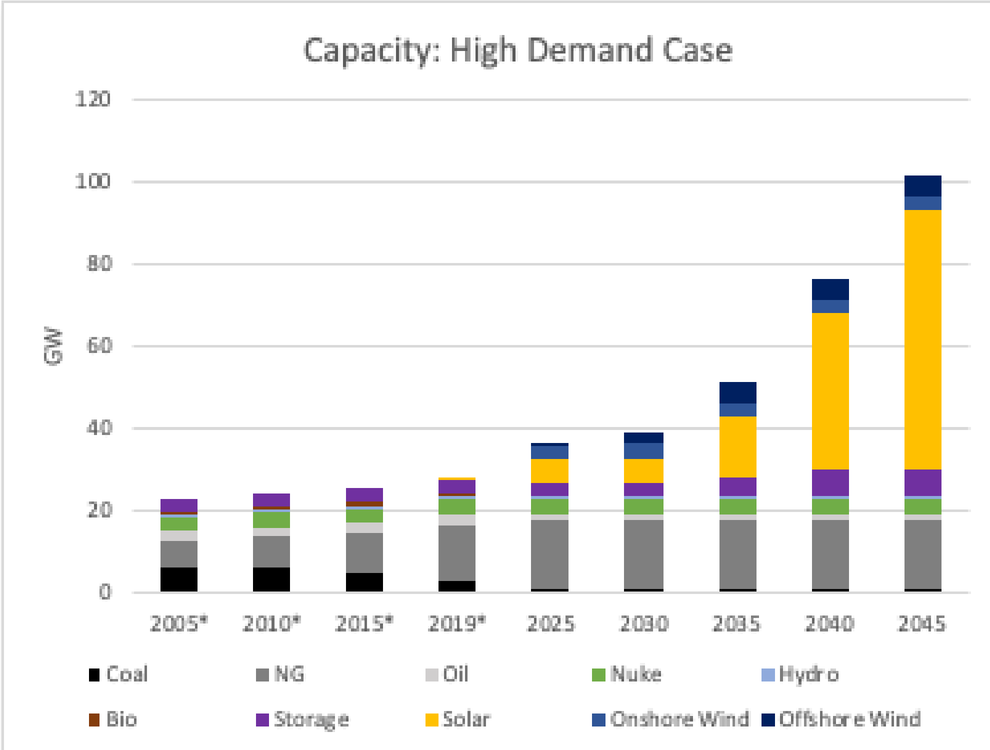


Figure 6: Electricity Sales - Baseline and High Demand Scenarios

The High Demand scenario uses the combined high data center/high EV forecast to assess how high demand growth might affect ratepayer costs and the ability to meet the VCEA requirements. The high EV penetration scenario is not a forecast but rather an illustrative calculation of the net benefits that might be achieved by a rapid transformation of the light duty vehicle fleet.

1. Virtually all of the increased expenditures on electricity are data center sales and EV charging. Residential and commercial (ex. data centers) payments do not increase.
2. Expenditures on EV charging represent a net savings for consumers and a large net reduction in CO_2 emissions.
3. Consumers in 2040 will be spending on the order of $2 billion for electricity and saving approximately $5 billion per year in fuel and maintenance costs. These amounts double by 2050 when, according to this scenario, EVs nearly fully replace internal combustion engines.
4. CO_2 emissions from the transportation sector fall by 22 million short tons per year by 2040 and double that in 2050, when CO_2 emissions from light duty vehicles are almost completely eliminated.
5. Emissions from the electricity sector do not change appreciably due to the combined effect of the RPS, RGGI and the renewables capacity targets.
6. All of the increased generation needed to meet the increased demand is met with increased solar and battery storage. The solar capacity built is greater than the targets specified in the VCEA. Assuming that the costs of solar installations do not rise with the scale of implementation, the model envisions the construction of nearly 65 GW of utility-scale solar by the end of the policy horizon. If the costs of utility-scale solar installations do rise at these high saturation levels, then, according to the ATB2020, the cost-effectiveness advantage would shift in favor of onshore wind along with commercial and residential solar.
7. With the model’s choice of 3.3 GW of onshore wind, solar capacity is 17 GW in 2040. Without the onshore wind, the solar capacity would need to expand to 25 GW.
8. Imports would increase from around 20 TWh/year to 40 TWh/year. While, at first, it might seem that this would increase emissions for PJM or the nation, this is probably not true. The services produced by data centers locating in Virginia are a near perfect substitute for the services produced by data centers built elsewhere. This demand substitution is not accounted for in the model. Thus, increased imports due to increased data center demand in Virginia compensate for increased data center demand that would otherwise occur outside of Virginia. And since the VCEA defines the RPS targets in terms of energy sales in Virginia, increased imports should not significantly affect global emissions.



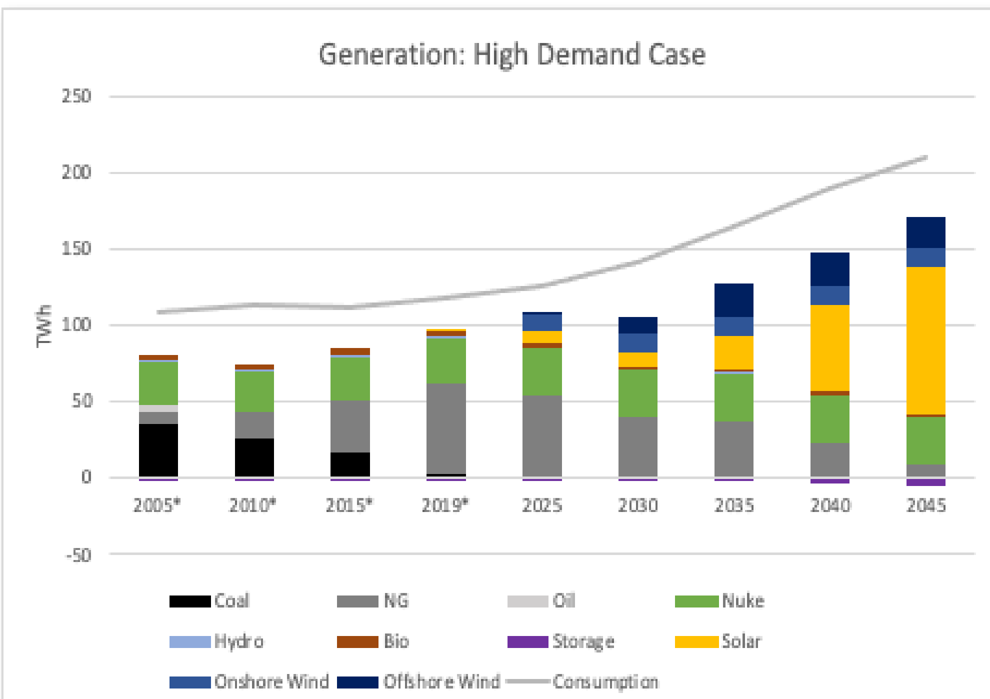


Figure 7: Capacity and Generation – High Electricity Demand Scenario

POLICY SCENARIOS

Scenario Name	Description
noCoalMin	Policy without coal minimum generation; economic shutdown
highEE	Policy with EE extended past 2026
noVCEACapTarget	Policy without capacity targets, RPS is in place
RPS2045	Policy with 100% RPS in VA by 2045 (75% of compliance in state)
RPS2045in	Policy with 100% RPS in VA by 2045 (all compliance in state)
VACap	Policy with 0 emissions in 2045 in VA cap
highConsDCout	Policy with high demand but data centers can meet their renewable requirements in PJM
highConsDCin	Policy with high demand but data centers must meet their renewable requirements in VA

The next set of scenarios explore what features of clean energy policies can help lower costs to ratepayers. The focus of these modeling exercises is on the cost of building, operating and maintaining the generating equipment necessary for meeting the realized demand. Accordingly, costs include the resource costs for building, fueling and maintaining generation equipment. The cost of importing electricity is included since in most years, in all scenarios, Virginia is a net importer of electricity, although generally less so than in the recent past.

The scope of this analysis is limited in a number of important ways:

- The analysis does not include an evaluation of the regulatory structure under which the electricity sector operates. The model applies a standard, economy-wide rate of return for all investments and does not distinguish between resources built by regulated and non-regulated entities. The question of the organizational structure under which resources are managed applies equally to all energy resources and is not limited to the case of planning for the elimination of CO_2 emissions from the electricity sector, which is the subject of this study.
- Since the focus of the analysis is on total resource costs, reported costs do not include pure transfers of value from one set of ratepayers to another. For example, the earnings from the RGGI allowance auction reflect a transfer of value rather than a use of resources. By law, utilities can recover the costs of the allowances through a surcharge on ratepayers, while the revenues are applied by the state to energy efficiency programs benefitting low-income households and to assisting localities in managing increased flood risk, a risk directly tied to increased concentrations of CO_2 in the atmosphere.

- This study does not analyze differential effects on different classes of ratepayers. The focus is on least-cost to ratepayers in aggregate, as specified in the study mandate. The VCEA explicitly provides for periodic studies of differential rate impacts. Analyses of these differential rate impacts, for example, studies of the benefits and burdens that may be felt by historically economically disadvantaged communities, will be undertaken separately from this effort.

1) Least-cost pathways without specific capacity targets

Offshore wind is currently a relatively expensive renewable energy resource. (See Figure 3: Estimated Levelized Cost of Energy for Various Technologies.) Given the current trends in renewable energy costs estimated by NREL, expanded offshore wind is expected to continue to be more expensive than other available generation technologies, especially utility-scale solar. The same consideration applies to batteries for storing electricity. While there is understandable excitement about potential new energy storage technologies, model results using the NREL mid-range cost estimates for battery technology do not support an economic case for installing substantial amounts of local electricity storage in the near term. The modeling does indicate that investments in battery storage capacity are likely to be cost-effective in later years of the planning period as battery costs decline and as the percentage of generation from intermittent renewables increases.

Several factors could make increased battery installation more attractive than is justified purely on the basis of overnight capital costs for batteries that smooth the availability of renewables. Batteries can provide a number of other valuable services to the grid and can contribute to grid resilience. If these battery services are compensated according to the value they provide, then investment in battery storage should occur in the course of a least-cost planning and implementation for a decarbonized grid, rather than as a mandated capacity target. This suggests that there should be an increased focus on correctly compensating storage capacity for its full value to the grid.

The ***noVCEACapTarget*** scenario includes all of the current provisions of the VCEA except for the specific technology capacity targets for wind, solar and storage. Because of its relatively advanced stage of development, the capacity target for the first 2.7 GW of offshore wind was retained for this scenario. All other specific capacity targets were removed in order to explore which technology mix will result in the least-cost path for ratepayers. Because utility-scale solar and onshore wind have the lowest levelized cost of energy in the ATB2020, the RPS and RGGI components of the VCEA are sufficient to encourage the deployment of utility-scale solar, at levels in excess of the explicit capacity targets included in the VCEA. Based on information from PJM, it is very likely that Virginia will have 3 GW of solar generation in service by the end of 2022 with much more in the early planning stages.

> The offshore wind capacity and some of the targeted storage are more expensive than other available options, including the expansion of commercial and residential solar. Eliminating the capacity targets for expanded offshore wind and for electricity storage, and allowing deployment of these resources to be guided by investor decisions about how to meet the RPS and RGGI requirements cost-effectively will likely save money for ratepayers.

The explicit capacity expansion goals for renewables and storage specified in the VCEA may be cost effective if costs or performance characteristics of these technologies continue to rapidly improve. Nevertheless, the RPS and RGGI policies are sufficient for meeting the state's goals for eliminating carbon emissions from electric generation. Specific technology targets in addition to those policies will tend to increase costs to ratepayers. Removing the additional offshore wind capacity target causes the substitution of lower cost solar for the added offshore wind. The modeling suggests that the explicit off-shore wind and energy storage targets could cost ratepayers more than $250 million per year in 2035 compared to the least-cost strategy. This cost penalty for ratepayers rises to $450 million per year by 2040, given the baseline cost assumptions for wind, solar and storage technologies.

There is an argument to be made that the cost of offshore wind deployment is overestimated, in particular for the years after 2025. It may be that there will be significant cost reductions from "learning by doing". The building of the first few wind farms could cause a sharp downward shift in costs. If this is true, then Virginia ratepayers may gain by a delay in the building of offshore wind until further cost reductions in off-shore wind technology have been realized as a result of investments by other states and countries. Once firms have experience with offshore wind deployment in the U.S., then Virginia could hold a procurement auction for future wind deployments off its own coast.

The analysis did not include possible regional economic benefits of new industrial development in Virginia that could arise because of deployment of offshore wind generation resources. Insofar as such economic development benefits may arise, they are likely to be largely confined to coastal regions of the state, while the effects on ratepayers will be statewide.

If a decision is made to develop offshore wind for potential economic development benefits, it may be worth considering whether there are mechanisms for matching more closely the payments made and the economic development benefits received.

2) Regional flexibility and procurement of renewables from within PJM and beyond

The cost-effective use of renewable energy has an important geographic component. First, since the potential for low-cost renewables generation is not evenly distributed across the country, different regions may have distinct advantages in renewables generation; for example, wind in the Midwest and solar in the South and Southwest. Second, and less obvious, is the temporal complementarity between wind and solar within and across regions of wind and solar generation. Connecting the renewables supply across resources and regions smooths local renewables variability. For these reasons, there may be considerable savings to ratepayers from allowing renewables procurement from other places. An obvious geographic extension for renewables procurement in Virginia is the PJM region, since the supply of electricity across this region is simultaneously determined by PJM operators given all of the encompassed generation resources.

The model scenarios demonstrate the dramatic savings possible by extending the geographic scope of sourcing renewable energy. The modeled scenarios include two different Virginia RPS scenarios, both of which achieve 100 percent non-emitting power by 2045. In one scenario, ***RPS2045in***, all RECS must be acquired within Virginia. In the alternative scenario, ***RPS2045***, RECS could be acquired anywhere in the PJM service region. Implementing a renewable portfolio standard requiring 100% non-emitting energy by 2045 is technically feasible with all in-state sources but would likely be much more expensive than an equivalent RPS allowing imported renewable energy credits to cover a significant share of generation. The modeling results suggest that the go-it-alone approach to the RPS would cost Virginia ratepayers an extra $400 million per year by 2040 compared to allowing 25 percent imported RECS, and the costs would rise substantially as the state approached the 100 percent goal in 2045. Increasing the allowable REC imports beyond 25 percent would further reduce ratepayer costs.

The strong conclusion one can draw from these modeling exercises is that costs to ratepayers can be reduced by increasing geographic flexibility in the source of renewable energy. This can be done without increasing CO_2 emissions. The CO_2 emission profiles of these competing approaches are virtually identical.

The broader lesson supported by the modeling results is that restricting the focus to Virginia in designing an emission reduction strategy will generally increase the cost of achieving a given reduction in emissions. This is certainly true in the case of the procurement of renewables but applies equally to the overall approach to emission reductions. A regional approach will generally cost less than a go-it-alone strategy.

Another model comparison reinforces this point. One of the modeling scenarios imposes a cap on Virginia emissions separately, and this cap declines to zero by 2045 but does not allow any trading in RECS or RGGI allowances for compliance. It is instructive to compare this go-it-alone cap scenario, ***VACap***, with the baseline assumptions but without the specific technology capacity targets, ***noVCEACapTarget***. The only substantive difference between these scenarios is the reduced geographic flexibility in compliance. Again, the cost of restricting trade is large, amounting to over $600 million per year in higher costs by 2040, *without any gain in emission reductions*.

A regional approach to capping emissions is effective in controlling emissions and produces considerable savings for ratepayers.

3) Pathway without a minimum on coal generation in years prior to 2045

The Baseline Scenario retains the Virginia City Hybrid Energy Center coal generation as proposed in Dominion Energy's Integrated Resource Plan. As a result, the VCHEC operates at a very low capacity factor in our Baseline Scenario, essentially operating as a seasonal peaking facility during winter and summer days, when demand spikes due to high heating and cooling loads. In the 12 months prior to August of 2021, the VCHEC had four months where it did not generate any electricity. The ***noCoalMin*** scenario relaxed the Baseline Scenario assumption that the VCHEC operate through to the end of the policy horizon. This scenario allowed the plant to be retired on purely economic grounds, in which case, the plant retires by 2025. Operating cost savings alone are on the order of millions of dollars per year. The Virginia State Corporation Commission staff estimates that the plant has a negative net present value of over $472 million over the next 10 years.[10] The Haiku model estimated savings are not directly comparable to the SCC calculations but are entirely consistent with the conclusion that the VCHEC should retire by 2025 on economic grounds and that the losses associated with keeping it open rise over time.

In weighing the costs and benefits of closure, policy makers may want to consider both the local economic effects of shifting generation and the gains in health outcomes resulting from lower fossil fuel combustion.

[10] Virginia State Corporation Commission. Prefiled Staff Testimony. September 29, 2020.

Local communities face concentrated local costs due to losing an important local industrial plant. This must, in turn, be weighed against the more diffuse but equally real cost to the rest of the state economy. As a result of the payments made to keep the VCHEC open, ratepayers in the rest of the state have less to spend in their own local communities.

The health costs from emissions by fossil fuel power plants are also unequally distributed. There is strong evidence of persistent inequalities in exposure to damaging pollutants, with lower income communities suffering disproportionate health effects from current levels of emissions (Colmer et al., 2020).

> The economically optimal retirement date for all of the remaining coal generation fleet is prior to 2025. With the VCHEC having a large negative net present value, there are clear opportunities for reducing ratepayer costs, improving health outcomes and providing economic relief and development assistance to the community around the VCHEC.

4) Land-use and utility-scale solar

The VCEA's solar and onshore wind capacity target of 16.1 GW of capacity by 2035 is broadly consistent with the least-cost generation capacity choice for that year. Given the current available technology, it takes approximately 6 acres of land for each MW of solar capacity.[11] This implies that in 2035, the modeled utility-scale solar deployment would require about 96 thousand acres. This amounts to approximately 1.1 percent of Virginia's land area. This level of land use change is comparable in size to other land-use changes that have taken place in the past, for example, for roads and urban development, but the solar deployment would occur at a much faster pace.

In the later years of the planning horizon, and especially in the high consumption scenarios, the amount of land required for solar deployment would be considerably larger. As an extreme example, in the high consumption case where only in-state renewable resources were allowed, the land required would account for more than 5 percent of the total land area of the state. This case would certainly face increasing prices for land for solar deployment and, potentially, conflicts with other land uses. In this case, there would be the substitution of other resources for utility-scale solar. In particular, commercial and rooftop solar would become increasingly competitive, as would offshore wind.

[11] https://www.solarlandlease.com/how-much-land-does-a-solar-farm-need

These potential constraints on land-use changes are not accounted for in the modeling exercises. But the model does demonstrate that, allowing for compliance using renewable resources from outside of Virginia keeps solar land area requirements to a more manageable two percent of the state's land area. This illustrates, again, the value of regional flexibility in meeting the renewable energy requirements.

OTHER POSSIBLE TECHNOLOGIES AND APPROACHES

The modeled scenarios have considered only a subset of the many technologies for generation and storage that may become cost-effective in the later years of the policy horizon. To provide guidance relevant to short-run decision making, the modeling exercise is restricted to consider technologies for which costs and operating characteristics can be readily determined. This restriction excludes from the modeling a number of promising technologies, currently in development, that may be available to make cost-effective contributions before the 2045 policy horizon. It is almost certain that some technology breakthroughs will bring the cost of one or more of these alternatives into competitive range. Virginia needs to track the availability of alternative technologies and ensure that the most cost-effective resources are being encouraged in the energy procurement process, subject to social and environmental constraints. One successful strategy that has been used is to hold open procurement auctions that are technology neutral.

Among the potential technologies that may be available before the end of the policy horizon are:

1. Technologies for generation and storage

- New nuclear technologies: small modular fission reactors or even nuclear fusion
- Geothermal energy for electricity generation
- Floating wind turbines for deep offshore wind (2030 cost target, ~$50-60/MWh)
- Natural gas and bio-energy with carbon capture and storage
- Landfill gas (LFG)[12]

2. Storage

- Hydrogen, ammonia and other synthetic fuels
- Advanced physical and chemical storage
- Compressed air storage
- Advanced batteries including bulk storage technologies
- Vehicle-to-grid technology

12 Large landfills in Virginia already capture and burn landfill gas. This study did not address where there is a significant opportunity to expand the electricity generated from LFG.

3. Competitive procurement of new generation

Evidence from a variety of sources suggests that competitive procurement of new renewable generation capacity has been a key driver of declines in wind and solar costs (Fitch-Roy et al., 2019). Given that wind and solar resources will almost certainly be central to Virginia's energy future, some consideration to enhancing the state's capacity for using procurement auctions to acquire new generation could help lower future deployment costs, facilitate integration of cost-competitive emerging technologies, and reduce the cost to ratepayers of achieving a decarbonized energy supply.[13]

> Virginia should enhance the state's capacity for using procurement auctions to acquire new renewables generation.

4. Enhanced energy efficiency

Energy efficiency as a resource will be discussed in more detail in a subsequent section of this report. Energy efficiency (EE) is an unusual resource in that the focus is on reducing demand rather than increasing supply. There is good evidence that energy efficiency represents a large and potentially inexpensive resource (Lovins, 2018). If successful at reducing energy demand, EE substitutes for the most expensive energy source, lowering consumer costs. If peak demand is reduced, the benefits are greater still. It has the added benefit of potentially eliminating the need for costly upgrades to the transmission and distribution system.

The high energy efficiency scenario demonstrates the potential value of energy efficiency investments by extending the current energy efficiency resource standard (EERS) beyond 2025. The modeling suggests that the EERS does not have its effect primarily on generation in Virginia; in-state generation changes very little. The extended EERS acts by reducing imports. The reason for this is that the existing VCEA policies, including the renewable and storage capacity targets result in the deployment of a minimum capacity of non-emitting resources regardless of the level of demand. Wind, solar and storage capacity have low marginal costs of operation, and substitute directly for higher marginal cost resources, especially coal, in the rest of PJM.

Assuming that adequate monitoring and evaluation mechanisms can be implemented, even the modest existing EERS could save around 10 TWh of electricity per year by 2035, resulting in over $1 billion in consumer savings per year by 2035. Based on an estimated average cost of $58/MWh for energy efficiency savings, consumers would have net savings of over $400 million per year. This estimate does not include cost savings from avoided capacity upgrades to the transmission and

[13] For additional discussion see: https://www.irena.org/policy/Renewable-Energy-Auctions and http://www.open-electricity-economics.org/book/text/09.html and https://www.usaid.gov/energy/auctions.

distribution system. What is not as well understood is the true cost of implementing these measures, and the likelihood of achieving the targeted demand reductions. Empirical studies have shown that many seemingly sensible policies for reducing energy intensity do not achieve the predicted savings (Fowlie et al., 2018). Ensuring cost-effective implementation of efficiency programs depends critically on implementing effective incentives along with effective institutional arrangements in place for truly independent monitoring and evaluation. This is discussed in more detail in Section 6.

It is important to note that energy efficiency efforts *for the whole economy* may increase demand for electricity. As already discussed, the shift to EVs increases both electricity demand and efficiency of energy end-use. EVs are much more efficient than internal combustion engines in the transformation of primary energy into transportation services. The electrification of building heating and cooling has the same dual effect of increasing electricity use while decreasing overall energy use. Models of economy-wide decarbonization uniformly show the importance of electrification of energy end-uses for both improved efficiency and decarbonization. Broader electrification of energy services adds to the need for an expanded, non-emitting energy supply.

COMPLIANCE FLEXIBILITY AND LOWERING DECARBONIZATION COSTS

The modeling confirms a general result that is supported by both economic theory and evidence: for a given emission constraint pathway, increasing compliance flexibility reduces compliance costs. Flexibility can come in many dimensions, but three merit special mention: flexibility in timing, technology and geography. Allowing compliance flexibility in each of these dimensions can produce substantial savings in ratepayer costs. Because greenhouse gas emissions have their effects at the global level and depend on the total stock of emissions rather than on emissions in a given year, flexibility offers gains with no significant changes to the level of ambition of the emission reduction goals. Flexible compliance implies that the mechanism for controlling emissions focus on total emissions rather than on the specific mechanisms used to reduce them.

Compliance flexibility and the associated cost savings are the key advantages of “cap and trade” emission control programs such as RGGI. The total cap over the compliance horizon defines the level of ambition. Given this level of ambition, sources have the greatest possible flexibility in choosing when, where and how to meet the target. The observed market price of allowances guides compliance choices and induces innovation in the same way that the price provides these same incentives in normal markets for goods. Sources can shift compliance obligations across time. In the case of an emission cap that declines over time, sources can be expected to comply early and bank emission allowances for later periods. The market price also provides policy makers with important information about the market participants’ perceptions regarding future levels of scarcity. This information can be used by policy makers to adjust the level of ambition accordingly. In practice, the Regional Greenhouse Gas Initiative has lived up to expectations, driving lower compliance costs and ultimately greater ambition in future emission reductions.

The revenues from the sale of RGGI allowances can be recycled to the benefit of ratepayers in a number of ways. The VCEA mandates that the allowance revenues be split between energy efficiency measures and flood resilience planning. Other possible strategies for recycling revenues include rebates of some share of revenues directly back to ratepayers or reductions in other state tax rates. These strategies retain the cost-savings inherent in the market-based allowance trading framework but passes some revenue directly back to ratepayers rather than allocating all of the allowance revenues to fund specific programs such as energy efficiency and flood resilience programs. An alternative mechanism for managing allowance value is the strategy chosen by DEQ in its initial regulation for joining RGGI. DEQ’s innovative approach used a consignment sale to return all net allowance value directly back to ratepayers. Each of these revenue assignment strategies retains the cost effectiveness of the market-based approach but makes a different choice about how allowance value is returned to the economy.

Economic theory and a considerable body of empirical evidence shows that market-based emission controls such as RGGI are most likely to achieve the least cost emission reduction pathway.

> RGGI should be considered a key mechanism for reducing costs to ratepayers of achieving zero emissions by 2045.

A recent study for PJM by the firm E3 on how to achieve 80% reductions in greenhouse gas emissions by 2050 reached very similar conclusions to this study about least cost pathways (Energy and Environmental Economics, 2020).[14]

- All PJM coal plants retire by 2030
- Legacy nuclear generation is kept in service
- Natural gas capacity is kept in service, and possibly converted to low carbon fuels, but is run at lower capacity factors in later years
- Solar and onshore wind are the primary additions to capacity, becoming the majority of generation later in the policy horizon
- Offshore wind supplements onshore wind in later years.

The PJM study also emphasized the value of flexibility in achieving any given decarbonization goal. It shows that a policy that focuses directly on greenhouse gas reductions is more cost-effective than mandating the use of specific technologies for achieving those reductions. The least cost scenario relies on capping GHG emissions and allowing trading of allowances among sources, as with the RGGI program. A cap that declines over time to the emission objective can reliably achieve the desired emissions reduction goal but with the maximum flexibility in how that reduction is accomplished. Such a policy is technology and geographically neutral, and encompasses all possible modes of reduction including demand reduction, carbon free generation and GHG capture by sources. A declining cap can also allow temporal flexibility by defining a total emission budget during for a given period of time and allowing some flexibility in the rate of reduction.

A close-second policy choice, in terms of cost-effectiveness, according to the E3 study, is a technology neutral clean energy standard (CES) with the opportunity to trade clean energy credits. A technology neutral CES provides flexibility in mode, geography and timing of reductions. The focus is on emission-free energy sources rather than on renewables in particular. This approach makes available a number of additional opportunities for GHG reduction such as bio-energy with carbon capture or zero-carbon synthetic fuels.

[14] See Energy and Environmental Economics. (October 2020) *Least Cost Carbon Reduction Strategies in PJM. https://www.pjm.com/-/media/committees-groups/task-forces/cpstf/2020/20201208/20201208-item-03b-e3-least-cost-carbon-reduction-policies-in-pjm.ashx*

One concern raised by the E3 study is the potential for “leakage” where some member utilities in PJM are not subject to emission charges or constraints. As emission reduction costs rise, the amount of generation shifting is also likely to rise. Without “border adjustments” that require imported electricity to face the same abatement costs as local generation, leakage can undo much of the local emission reductions. Appropriate border adjustments can retain the advantage of compliance flexibility without resulting in emission leakage.

ADDITIONAL FACTORS FOR LEAST-COST DECARBONIZATION PATHWAYS

RESOURCE VARIABILITY, RELIABILITY AND RESILIENCE

In approaching the task of eliminating CO_2 emissions from the state's electricity supply, Virginia starts from a position of relative strength. With 3.7 GW of nuclear baseload generation, 14 GW (or more) of natural gas capacity and substantial interstate transmission capacity, the electricity sector is in a position to absorb substantial quantities of solar and wind without generating concerns over resource reliability. Even with the VCEA capacity targets, the electricity supply will be less than 30 percent variable renewable resources up until about 2035. Considerable time exists to prepare for an electric grid in which renewable generation exceeds 50 percent, which will likely occur around 2040. Experience from other states and countries suggests that, until this point is reached, the increasing contribution of renewables need not force major changes in supply and demand management to maintain system reliability. Current uncertainty over what will be the best options and approaches in the later years of the policy horizon need not slow transition efforts, which in the near term should focus on development of onshore wind and solar generating capacity. There is room to plan and adjust as new technologies and techniques become available.

TRANSMISSION AND DISTRIBUTION SYSTEM COSTS

A recent PJM study evaluated the cost of a coordinated set of grid upgrades necessary and appropriate for harvesting approximately 14 GW of wind off the coast between New Jersey and North Carolina.[15] The study estimated that the coordinated set of grid upgrades would cost between $2.2 and $3.2 billion over the next several years. The implied costs (undiscounted) are between $188/kW and $210/kW. But not all of these costs should be counted as costs of offshore wind development. As acknowledged in the PJM analysis, many of these upgrades have value whether the offshore wind projects are built or not. Several important market efficiency improvements are generated by the transmission upgrades: congestion relief, reduced CO_2 emissions across PJM, a decrease in other renewable curtailments (especially solar) and a decrease in congestion load payments and locational marginal price differentials. In other words, this grid upgrade proposal creates very substantial benefits beyond the mere transfer of offshore wind electricity. Because these benefits of grid upgrades are overlapping and complementary, there is no obvious method to allocate the costs for the upgrade among the wider set of public goods.

[15] Offshore Wind Transmission Study: Phase 1 Results. (October 2021). PJM.

A study by The Brattle Group and Grid Strategies pointed out a striking feature of this grid planning exercise.[16] The cost of upgrades resulting from a careful, integrated regional analysis is half the cost of the transmission upgrades that would result from the piecemeal grid modifications that would occur through the normal interconnection queue approval process. As the Brattle Group study (along with many others) shows, the current grid planning and resource interconnection processes are not working well and are key friction points preventing more rapid and cost-effective incorporation of renewables to the grid.

The current interconnection process leads to a higher-cost transmission system, raising electricity costs and reducing the benefits of renewable integration. The current system also unfairly allocates costs to new projects because it fails to ensure that the beneficiaries of grid services "pay costs that are roughly commensurate with the benefits they receive." (Brattle 2021). Finally, the current process imposes unnecessary costs on renewables developers. This has several damaging effects. It reduces the profitability of renewables projects. It raises consumer costs. And because the interconnection process is a fixed cost of project development, it tends to push developers to propose larger projects than otherwise, generating frictions with local land-use planning authorities.

The modern grid, like the interstate highway system, is a public infrastructure that generates enormous social value. Its role is already shifting dramatically as new, more distributed, two-way energy services develop. The current grid structure is no longer a perfect match to the new energy technology landscape. Consequently, investment in grid modernization will be essential whatever mix of renewable and non-renewable energy technologies are chosen. Consumers will benefit from the investments, but allocating the costs to specific projects or users will often not be possible or beneficial.

A significant portion of the land in Virginia most suited for solar and wind deployment are sufficiently far from current transmission infrastructure that solar deployment in these areas is not currently cost-effective. Planning some grid expansion for the sole purpose of harvesting Virginia's solar resource cost-effectively may have significant public benefit, but Virginia has no ready mechanism for engaging in this anticipatory resource planning and expansion.

The approach to grid modernization and management should no longer follow the old model built around adding a few large generation sources and connecting them by high-voltage transmission to load centers. The electric grid is an energy services harvesting tool as well as a system for bulk, unidirectional transfer of electricity. Continuing to use antiquated processes for costly, incremental grid upgrades would raise the cost of grid services and reduce the value of the grid in facilitating the shift to non-emitting resources.

[16] Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs. (October 2021).

The Brattle/Grid Strategies study recommends that the grid planning process be organized around five planning practices:

1. Proactively plan for future generation and load
2. Apply a multi-value planning framework to all transmission projects
3. Use scenario-based planning to address uncertainties
4. Capture portfolio-level cost advantages and use portfolio-based cost recovery
5. Perform joint, interregional planning

The purpose of approaching grid planning in this way is that it reduces the cost of grid services and provides a better match between grid architecture and grid services value.

At the end of October 2021, the PJM interconnection queue for Virginia had 31 GW of solar capacity listed as "Active" and 3 GW at the more advanced "Engineering and Procurement" stage.[17] Unfortunately, based on recent experience less than a fifth of the "active" projects are likely to be completed. Working through the queue process takes years and involves a series of expensive interconnection studies that subject developers to wildly varying estimates of the grid upgrade costs that are to be assigned to the particular project.

Smaller renewable projects must use the interconnection queue managed by Dominion Energy. For solar projects in this queue, of those with completed interconnection agreements, the mean time between queue assignment and an executed interconnection agreement is over 682 days. This does not count the period before queue assignment. The delay and uncertainty impose large costs on developers, causing many to drop out and ultimately raise the cost of electricity to ratepayers.

Virginia would benefit by developing an active grid planning framework within the Virginia Department of Energy. The grid planning group could initiate planning and modeling activities outside of the traditional adversarial process of utility regulation. The group should be charged with helping coordinate a regional grid planning process to complement and expand upon the grid planning process at PJM. The grid for a decarbonized Virginia will not plan and organize itself. The savings to ratepayers is potentially very large. The Brattle Group/Grid Strategies study is the only exercise to date to compare the current ad hoc approach and the alternative coordinated regional planning approach. That study suggests that the coordinated approach could reduce transmission upgrade costs by half over the policy horizon, amounting to billions of dollars saved.

Twenty-five years is not a long time in the context of grid planning and deployment. The key issues extend beyond engineering and technical design questions. The new grid will require new means

[17] See: PJM New Services Queue.

for the financing of grid upgrades and the pricing of grid services. In many respects, these *soft* design questions are as challenging as those faced by the engineers.

HARVESTING ENERGY EFFICIENCY

Energy efficiency appears, on the surface, to be a large and low-cost resource for reducing emissions by increasing the end-use energy services obtained for each unit of energy input. Opportunities exist for increasing energy efficiency because the energy intensity of developed economies has been declining for several decades. This pattern, along with engineering studies, has led many observers to the conclusion that investing in energy efficiency is one of the least-cost resources available to us. Measuring the actual results of energy efficiency investments is very difficult (Tietenberg, 2009). Given the difficulty of measuring actual energy savings, much of the evaluation of energy efficiency efforts relies on estimated outcomes based on inputs or effort rather than actual energy savings. Fortunately, recent research suggests strategies for improved program design along with improved monitoring and evaluation of actual outcomes.

The key difficulty with estimates of the energy efficiency potential is understanding why we are not already getting the "right" amount of savings. In 2009, McKinsey and Company published a study claiming that there existed a huge energy efficiency resource that had *negative costs*, meaning it would be profitable for a firm to borrow at the market interest rate to invest in savings. The difficulty with this result was immediately apparent. If these investments were so profitable, why were investors not taking advantage of profitable investments? If they weren't, then either there was something getting in the way of profitable activities or the investments might not be profitable after all. This "energy efficiency gap" has been the subject of intense research since the publication of the McKinsey study.

A number of conclusions are now possible. First, many programs that appear cost effective don't account for the true opportunity cost of investing in efficiency, once you add up all of the costs. Second, some investments in energy efficiency do produce economic gains but don't save energy. Investments in efficiency lower the costs of using the services that the energy creates. As the services become cheaper, people will choose to consume more of the now cheaper services. This is often called "the rebound effect". There is a benefit to the consumer, just less energy savings than you expected.

The third issue is identifying the "market failures" that prevent people or investors from investing in the right amount of efficiency. Implementing a policy that tries to reap efficiency but doesn't address the reason for under-investment is likely to have unintended (or even perverse) consequences. There is a vast literature on this issue but still no consensus on what policies are best for addressing what market failures we think are present and what we can expect to reap from a given intervention (Gillingham & Palmer, 2014).

The fourth reason is possibly the most important. The true reductions in energy use due to a given public expenditure are devilishly hard to measure (Fowlie et al., 2018). Carrying out carefully designed, randomized control trials, can provide strong evidence about effectiveness. In cases where controlled experiments have been done, the results indicate that savings are generally much less than the engineering estimates. Some programs produce savings, others can actually increase energy use. Unfortunately, randomized trials are very expensive and administratively burdensome.

Recent advances in machine learning have provided an alternative, more feasible evaluation tool that can provide reasonably trustworthy estimates of the value of different efficiency interventions(Burlig et al., 2020; Prest et al., 2021). These evaluation methods use high time-resolution electricity meter data on individual customers to discover patterns of differences between those receiving the policy treatment and those not receiving the treatment. Researchers have recently used these techniques to effectively reproduce the results of randomized trials. This is an extremely promising area for advancing the ability to monitor, evaluate and re-target efficiency expenditures to maximize the gains in energy saved.

If Virginia is to depend on energy efficiency as a cost-effective contribution to decarbonization, then it is critical that the measure of success is not measured based on level of investment or numbers of specific efficiency measures installed but instead on empirically measured outcomes. To ensure this occurs, performance incentives mechanism need to be designed accordingly and there needs to be the appropriate administrative capacity outside of the organizations actually implementing the programs for oversight, monitoring and evaluation.

In 35 states, including Virginia, the administration and procurement of energy efficiency resources is the responsibility of the utility, pursuant to state legislative mandates. There are other alternatives to this model, such as a state agency serving as administrator, third-party administration, and hybrid models that several states have chosen to adopt (Sergici & Irwin, 2019). Oregon adopted the third-party administrator model as a result of state redistricting proceedings in 2002. The Oregon Public Utility Commission (PUC) created the Energy Trust of Oregon (ETO) to set energy efficiency resource standards and administer statewide energy efficiency programs. ETO is led by an elected non-stakeholder board of director and overseen by three advisory councils. The PUC defines metrics to evaluate ETO's performance and sets stringent evaluation, measurement, and verification (EM&V) standards (Sedano, 2011).

Accurate and verifiable EM&V is critical for a successful energy efficiency program. If programs are not thoroughly assessed, performance incentives lose their effectiveness and there is no basis on which to continually improve program design. To ensure transparent evaluation, some states require that eligible third parties have access to anonymized customer usage data. In Illinois, the Open Data Access Framework sets guidelines for securely authorizing and sharing customer data. The Illinois Commerce Commission has also approved data-sharing programs for ComEd, the states largest electric utility. These policies allow companies and independent researches to access smart meter data which increases transparency (Munson, 2017).

DEMAND RESPONSE

Demand response involves activities that shed, shift or shape behind-the-meter (BTM) electricity demand and supply to enable more efficient use of grid resources. The most expensive electricity to supply has generally been the kilowatt hours needed to meet peak demand. Capital costs of generation, transmission, and distribution system capacity utilized only during periods of high demand must be recovered from a relatively few kilowatt hours of output. Demand response technologies and programs that reduce peak loads can therefore provide substantial savings. One recent study estimated that investing in demand response capabilities and technologies could reduce peak loads by 20% and save U.S. ratepayers $15 billion annually by 2030 through avoided capacity and energy costs (Hledik et al., 2019). If enhanced demand response in Virginia yielded proportionate savings, then based on Virginia's share of national electric demand, Virginia ratepayers could realize more than $400 million per year in savings by 2030. This is likely a conservative estimate since demand response technology and business model innovation have continued to accelerate since the study was completed. A recent energy system modeling study estimated that demand response measures for building heating, cooling and hot water applications could reduce battery energy storage requirements for a decarbonized electric grid by nearly 60% in a climate zone of the U.S. that includes most of Virginia (Houssainy & Livingood, 2021).

Use of intermittent renewables as a significant source of electric generation increases the value and range of applications of demand response, extending it beyond conventional peak demand shaving to include a wide variety of measures designed to cost-effectively manage periods of excess demand relative to real-time renewable supply. Virginia is still in the early stages of the transition to an electric grid with high levels of intermittent renewables that also supports increased electrification of transportation and other end uses. Other states and countries have already advanced further down that path. In the process, demand response is evolving to encompass a much more diverse set of technologies, use cases and value streams. For Virginia, this provides the opportunity to learn from and build upon technology applications and business model innovations that have already been deployed and tested elsewhere. As Virginia moves to the forefront of the clean energy transition, demand response offers the potential to deliver substantial cost savings to ratepayers. Given the concentration of major technology companies, data centers, and large public sector energy users within the state, there is also an opportunity for the Commonwealth to become a hub for smart grid technology and business development.

1. Enabling behind-the meter supply and demand response

Conventional peak load shedding demand response has generally involved a direct interaction between utilities and their customers. The interaction has occurred through rate structures intended to reduce customer demand during peak periods and/or by utilities providing customers a bill credit in exchange for allowing the utility to install a device that can cycle energy using appliances, typically hot water heaters and air conditioners, on and off during periods of peak demand. Some large commercial and industrial ratepayers have employed energy service companies to assist in managing their load curves to minimize utility bills but savings available to residential and smaller commercial customers were rarely substantial enough to support use of third-party services and expertise.

With the expansion of smart metering and smart BTM technologies, this landscape is changing rapidly. An expanding set of energy management companies are using smart communication enabled technologies, to manage BTM resources for commercial and industrial as well as residential accounts. Based on customer defined preferences and price points, these companies remotely and automatically access demand response resources across their customer base, and on behalf of their customers, sell the aggregated demand response capacity and output on retail or wholesale electricity markets. Management of the resource and execution of energy market transactions occur without any ongoing involvement from the ratepayer with the savings credited on the ratepayer’s utility bill.

2. EV integration

Continued market penetration and cost reductions of EVs has the potential to significantly expand demand response and improve grid capacity utilization, while also reducing transportation related emissions of CO_2 and other air pollutants (Blonsky et al., 2019; Malmgren, 2016). Miles traveled per charge for electric vehicles is steadily increasing which provides most EV owners with substantial flexibility regarding when to recharge their vehicles. Studies have shown that EV owners are willing to modify charging times given appropriate incentives to do so (EA Technology, 2019). This creates a very substantial demand response opportunity. Realizing the load leveling potential of EV’s will require coordinated deployment of distribution system and charging infrastructure investments, dynamic rate structures, and smart grid capabilities.

Demand response and grid management benefits of EV’s will be further magnified as two-way charging technology is commercialized. Bidirectional vehicle-to-grid (V2G) and vehicle to home, business, etc. (V2X) charging technology enables EV’s to draw electricity from the grid to recharge batteries and to discharge power from the batteries back to the grid or to meet on-site customer demand. With V2G or V2X charging, EV’s provide the grid with time flexible load as well as distributed storage capacity.

Since EV owners will be purchasing their vehicles primarily for transportation, a substantially lower level of ratepayer funded capital investment is required to benefit from the energy storage capacity of EV’s as compared with development of dedicated utility scale storage capacity. Conversely, providing financial incentives to EV owners for optimized EV charging and V2G supported energy storage and discharge back to the grid would be expected to accelerate EV adoption and charging technology development.

3. Tariff design

Dynamic pricing of electricity, including time-of-use (TOU) rates, peak demand surcharges (or rebates for reductions), and real-time pricing (RTP), provides customers with financial incentives to reduce or shift loads and manage distributed energy resources (DERs), EVs, and energy storage to minimize energy costs. Rate based financial incentives are a critical driver of adoption and optimized use of systems and technologies that augment demand response.

Combining dynamic rates with supporting technologies, including programmable thermostats as well as smart, communication-enabled thermostats and appliances, increases demand response by a factor of two or more versus deployment of dynamic rates without accompanying BTM technologies (Faruqui et al., 2017). Dynamic pricing provides the incentive for ratepayers to provide demand response, while smart systems and equipment make it easier for ratepayers to respond to those incentives. Analysis of dynamic pricing programs also indicates that rate structure design is critically important. Larger differences in rates between non-preferred/high-cost and preferred/low-cost demand periods and shorter duration non-preferred/high cost demand periods generate larger demand response per customer and higher rates of customer participation (Faruqui et al., 2019; Sherwood et al., 2016). Smart systems that include smart meters, thermostats, appliances, and energy storage systems allow for more precise and automated opportunities for households and businesses to react to time-varying rates. The converse is also true. Dynamic pricing unlocks the potential of smart meters and smart BTM systems and devices, augmenting customer demand response.

4. Smart grid technologies

In addition to smart BTM technologies and dynamic rate structures, smart grid technologies, such as smart meters and associated information management systems, are needed to maximize grid-level demand response capabilities. Smart meters enable design and implementation of more sophisticated and time sensitive rate structures. A series of studies conducted using detailed customer use data in Illinois found that smart meters combined with rates that reflect the time varying costs of service delivery can also have significant benefits for many lower income rate payers (Zethmayr & Kolata, 2018; Zethmayr & Makhija, 2019).The analysis found that many lower income households have flatter electricity use patterns throughout the day and across seasons compared with commercial and more affluent residential ratepayers. This allows for the design of rate structures that provide effective incentives to reduce peak or excess demand, while reducing total utility costs for low- and moderate-income households.

Smart metering technologies and associated customer data management systems also provide ratepayers and third-party energy service companies with more detailed data with which to optimize use of BTM technologies. Residential and business customers can obtain much more detailed on-line data and reports on their electricity use over time and in comparison to other customers in their rate class. Third-party demand response aggregators utilize these data and the enhanced communication capabilities of smart metering systems to assist customers in optimally responding to time varying rate structures and other demand response incentives.

5. State policies

Numerous states have implemented utility performance incentive mechanisms to promote investment in demand response and ensure those investments yield benefits for ratepayers (Gold et al., 2020). A review of California's experience with demand response indicates that the design of state policies and regulatory mechanisms, rather than technical or economic factors, have limited the use of demand response as a resource for cost-effectively balancing supply and demand (St. John, 2020). Massachusetts has implemented a Clean Peak Energy Standard (CPS) to accelerate investment in technologies and operational management systems that can supply clean electricity or reduce electric demand during specified peak periods defined by the state. Any clean energy or energy storage resource that generates, dispatches, or discharges electricity to the grid, or reduces demand, during designated peak periods generates Clean Peak Certificates. Retail electricity suppliers can develop or purchase CPCs to achieve annual legislative mandated targets.

DISTRIBUTED ENERGY RESOURCES

Due in part to prior restrictions on development of distributed energy resources (DERs) in Virginia, distributed solar currently supplies well under 1% of Virginia's electricity demand. Other states have demonstrated that much higher levels of distributed solar output can be achieved and successfully integrated into local and regional power grids. U.S. Energy Information Agency data indicate that in August 2021 distributed solar contributed more than 14% of Hawaii's electric generation and nearly 14% of electricity generated in California.

For purposes of this report, a key question is whether relying more significantly on DERs will increase costs to ratepayers of achieving a zero-carbon electricity supply for Virginia. Estimates of the levelized cost of electricity from different technologies indicate that distributed solar is several times more expensive than utility scale solar but is currently less expensive than offshore wind. Although the absolute magnitude of the cost differential between distributed and utility-scale solar is projected to decline over time as costs of both technologies continue to decrease, distributed solar is expected to remain more expensive.

Given the VCEA's steadily increasing RPS mandates, the financial value to ratepayers resulting from DER investments is not a function of overall generation capacity mix and average fuel costs for Virginia's investor owned utilities. Instead, it is the avoided marginal cost of obtaining renewable energy credits from utility scale renewables plus avoided transmission and distribution costs. One least-cost grid decarbonization study found that including analysis of transmission and distribution capacity requirements, as well as the demand response potential of distributed solar and storage, boosted investments in DERs, reduced utility scale storage investments and yielded substantial cost savings compared with scenarios that did not take these costs and capabilities into account (Clack et al., 2020).

In addition to these direct ratepayer impacts, increased development of DERs can help to avoid or reduce land-use conflicts associated with utility scale renewables. Energy system modeling conducted for this report indicates that achieving the RPS mandates of the VCEA could require utility scale solar development on over 1% of the land area of Virginia. Since prime locations for utility scale solar (relatively flat land close to existing infrastructure) often overlap with productive farmland and areas with high potential for residential or commercial development, there will be competing interests and proposals for use of land that is well-suited for utility-scale solar development. These land use conflicts can delay development of utility scale solar projects and increase costs if utility scale solar must utilize sites with steeper slopes and/or greater distance to transmission lines.

The advantage of distributed solar is that it does not require a greenfield site. Almost all distributed solar facilities, whether rooftop, canopy, or ground mount, are located on parcels that are also being used for other purposes. Supporting expanded DER development will reduce the need for utility scale solar which would be expected to alleviate potential land use conflicts involved in meeting the RPS mandates of the VCEA. A recent study of the rooftop solar production potential of all 50 states found that installing rooftop solar on existing buildings with high solar potential could provide more than 30% of Virginia’s current annual electricity consumption (Gagnon et al., 2018). Additional distributed solar capacity could be provided from canopy systems on parking areas, as well as ground mount systems located on landfills, publicly owned roadway buffers, and larger suburban or ex-urban parcels.

Continued investment in distributed solar is occurring alongside an accelerating transition to electric vehicles and rapid innovation in BTM storage and energy management systems. New technologies reaching commercial stage include bi-directional V2G and V2X charging systems for EVs and smart inverters that can automatically isolate DERs from the grid to provide power during system outages, help manage voltage fluctuations on the grid, and enable more efficient integration with distributed storage (Silvia, 2021; St. John, 2021).

Studies have also shown that households and businesses choosing to invest in distributed solar are more likely to be early adopters of EVs, distributed storage and smart BTM technologies (Delman, 2018). They are also more likely to opt-in to time of use or other dynamic rate structures and be prepared to optimize energy use in response. Analysis of the costs and benefits of policies supporting expanded development of DERs must account for these linkages between adoption of distributed solar, EVs and BTM energy storage systems and other smart technologies that expand demand response capacity.

Continued market penetration of distributed solar also increases public participation and community engagement in Virginia’s energy transition. The most significant factor affecting whether a household has installed a rooftop solar energy system is whether one or more of their neighbors has recently installed one (Barton-Henry et al., 2021; Graziano & Gillingham, 2015). This suggest that an effective means of expanding the installed capacity and income distribution of households with rooftop solar is to target incentives to neighborhoods with lower concentrations of rooftop solar.

CONCLUSIONS

The modeling carried out for this study confirms a general principle, borne out by other studies, that flexibility in meeting GHG reduction goals lowers costs of achieving any given reduction target. Flexibility has many dimensions including technology, geography and time. The first step in achieving compliance flexibility is in choosing the policy target, which in the case of the VCEA is reductions in GHG emissions from Virginia's electricity sector. The targeted reductions can be achieved through various combinations of energy efficiency improvements, renewable energy, energy storage and other still-emerging technologies. Defining the goals to be met and providing appropriate incentives to achieve them while allowing utilities, independent power producers, and energy users flexibility in determining how best to balance supply and demand offers the greatest potential for achieving cost-effective results.

The method used in this study for exploring cost-effective strategies started with a Baseline Scenario intended to capture the key features of the VCEA. After exploring the sensitivity of the initial results to some of the key assumptions, alternative pathways were modeled. In every case, the modeling required that the electricity sector achieve full decarbonization by the end of 2045. The model results confirm the general observation that flexibility in compliance reduces ratepayer costs. Policies that specify technologies, local versus regional compliance or overly rigid time paths for reduction raise costs. Policies that focus directly on GHG emissions rather than on techniques for reducing them generate the greatest gains. Virginia, is a member of the Regional Greenhouse Gas Initiative, an example of a flexible GHG-focused approach.

The most significant, but limited exception to this general rule on flexibility is cases where a known "market failure" prevents consumers and producers from making effective responses to a price on GHG emissions. There is some reason to believe that energy efficiency is a large available resource for decarbonization, but that some efficiency opportunities are hampered by ineffective price incentives. In this case, and in the case of equity concerns, supplemental policies may be cost-reducing or result in increased public benefits. Available evidence suggests that cost-effectively harvesting this efficiency resource requires a demanding regime of monitoring and evaluation. Without effective monitoring, demand reduction due to efficiency efforts will be much less than expected and will be more costly than necessary.

Modeling results, and additional analysis conducted for this report, point to several possible ways of lowing the cost of achieving the goals of the VCEA:

- Allow compliance flexibility over technology, geography and time
- Provide flexibility in the timing of new renewables and storage
- Allow legacy coal plants to retire on an economic basis
- Explore options for reducing the "soft" costs of distributed energy resources
- Encourage the rapid transition to electrified light duty vehicles

- Recognize load shifting and demand management as an increasingly important resource for cost-effectively balancing supply and demand, especially as the share of intermittent renewable generation increases
- Develop a robust monitoring and evaluation framework for energy efficiency efforts
- Build the institutional capacity for regional transmission planning and finance

Making these marginal adjustments can be expected to substantially lower the cost of eliminating GHG emissions from the electricity sector by 2045.

REFERENCES

Barton-Henry, K., Wenz, L., & Levermann, A. (2021). Decay radius of climate decision for solar panels in the city of Fresno, USA. *Scientific Reports*, *11*, 10.

Blonsky, M., Nagarajan, A., Ghosh, S., McKenna, K., Veda, S., & Kroposki, B. (2019). Potential Impacts of Transportation and Building Electrification on the Grid: A Review of Electrification Projections and Their Effects on Grid Infrastructure, Operation, and Planning. *Current Sustainable/Renewable Energy Reports*, *6*(4), 169–176. https://doi.org/10.1007/s40518-019-00140-5

Burlig, F., Knittel, C., Rapson, D., Reguant, M., & Wolfram, C. (2020). Machine Learning from Schools about Energy Efficiency. *Journal of the Association of Environmental and Resource Economists*, *7*(6), 1181–1217.

Clack, C. T. M., Choukulkar, A., Cote, B., & McKee, S. A. (2020). *Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid*. Vibrant Clean Energy. https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_TR_Final.pdf

Cole, W., Corcoran, S., Gates, N., Mai, T., & Das, P. (2020). *2020 Standard Scenarios Report: A U.S. Electricity Sector Outlook* (Technical Report NREL/TP-6A20-77442). National Renewable Energy Laboratory.

Colmer, J., Hardman, I., Shimshack, J., & Voorheis, J. (2020). Disparities in PM2.5 air pollution in the United States. *Science*, *369*(6503), 575–578. https://doi.org/10.1126/science.aaz9353

Delman, B. (2018). *Survey examines solar's strong connection to electric vehicles—Solar United Neighbors*. Solar United Neighbors. https://www.solarunitedneighbors.org/news/survey-examines-solars-strong-connection-electric-vehicles/

EA Technology. (2019). *Powered-Up: Charging EV's Without Stressing the Electricity Network* (Electric Nation) [Case study report]. Western Power Distribution. http://www.electricnation.org.uk/wp-content/uploads/2019/10/Electric-Nation-Powered-Up-Report-WEB.pdf

Energy and Environmental Economics. (2020). *Least Cost Carbon Reduction Policies in PJM*.

Faruqui, A., Hledik, R., & Sergici, S. (2019). *A Survey of Residential Time-Of-Use (TOU) Rates* (p. 24). The Brattle Group.

Faruqui, A., Sergici, S., & Warner, C. (2017). Arcturus 2.0: A meta-analysis of time-varying rates for electricity. *The Electricity Journal*, *30*(10), 64–72.

Fitch-Roy, O. W., Benson, D., & Woodman, B. (2019). Policy Instrument Supply and Demand: How the Renewable Electricity Auction Took over the World. *Politics and Governance*, *7*(1), 81–91.

Fowlie, M., Greenstone, M., & Wolfram, C. (2018). Do Energy Efficiency Investments Deliver? Evidence from the Weatherization Assistance Program. *Quarterly Journal of Economics*, *133*(3), 1597–1644.

Fox-Penner, P. (2020). *Power after Carbon: Building a Clean, Resilient Grid*. Harvard University Press.

Gagnon, P., Margolis, R., Melius, J., Phillips, C., & Elmore, R. (2018). Estimating rooftop solar technical potential across the US using a combination of GIS-based methods, lidar data, and statistical modeling. *Environmental Research Letters*, *13*(2), 024027.

Gillingham, K., & Palmer, K. (2014). Bridging the Energy Efficiency Gap: Policy Insights from Economic Theory and Empirical Evidence. *Review of Environmental Economics and Policy*, *8*(1), 18–38. https://doi.org/10.1093/reep/ret021

Gold, R., Myers, A., & O'Boyle, M. (2020). *Performance Incentive Mechanisms for Strategic Demand Reduction* (p. 53). American Council for an Energy Efficient Economy.

Graziano, M., & Gillingham, K. (2015). Spatial patterns of solar photovoltaic system adoption: The influence of neighbors and the built environment. *Journal of Economic Geography*, *15*(4), 815–839.

Hledik, R., Faruqui, A., Lee, T., & Higham, J. (2019). *The National Potential for Load Flexibility: Value and Market Potential Through 2030* (p. 41). Brattle Group.

Houssainy, S., & Livingood, W. (2021). Optimal strategies for a cost-effective and reliable 100% renewable electric grid. *Journal of Renewable and Sustainable Energy*, *13*(6), 066301. https://doi.org/10.1063/5.0064570

Larson, E., Greig, C., Jenkins, J. D., Mayfield, E., & Pascale, A. (2020). *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*. Princeton University.

Lovins, A. B. (2018). How big is the energy efficiency resource? *Environmental Research Letters*, *13*(9), 090401. https://doi.org/10.1088/1748-9326/aad965

Malmgren, I. (2016). Quantifying the Societal Benefits of Electric Vehicles. *World Electric Vehicle Journal*, *8*(4), 996–1007. https://doi.org/10.3390/wevj8040996

Munson, D. (2017, September 27). The power of energy data in Illinois and beyond. *Environmental Defense Fund Energy Exchange*. http://blogs.edf.org/energyexchange/2017/09/27/the-power-of-energy-data-in-illinois-and-beyond/

Prest, B., Wichman, C., & Palmer, K. (2021). *RCTs Against the Machine: Can Machine Learning Prediction Methods Recover Experimental Treatment Effects?* (Working Paper No. 21–30). Resources for the Future.

Sedano, R. (2011). *Who Should Deliver Ratepayer-Funded Energy Efficiency? A 2011 Update*. Regulatory Assistance Project. https://www7.eere.energy.gov/seeaction/system/files/documents/rap_sedano_whoshoulddeliverratepayerfundedee_2011__11_15.pdf

Sergici, S., & Irwin, N. (2019). *Energy Efficiency Administrator Models: Relative Strengths and Impact on Energy Efficiency Program Success*. The Brattle Group. file:///C:/Users/student/Downloads/17632_2019_11_18__brattle-uplight__energy-efficiency-administrator-models%20(2).pdf

Sherwood, J., Chitkara, A., Cross-Call, D., & Li, B. (2016). *A Review of Alternative Rate Designs: Industry experience with time-based and demand charge rates for mass-market customers* (p. 88). Rocky Mountain Institute.

Shobe, W. (2021). *Electricity Sales Forecast for Virginia: 2020-2050*. Weldon Cooper Center for Public Service.

Silvia, T. (2021, October 25). Enphase launches microgrid-forming microinverter line. *PV Magazine USA*. https://pv-magazine-usa.com/2021/10/25/enphase-launches-microgrid-forming-microinverter-line/

St. John, J. (2020, September 22). Unlocking California's Gigawatt-Scale Distributed Energy Potential. *Greentech Media*. https://www.greentechmedia.com/articles/read/unlocking-californias-gigawatt-scale-distributed-energy-potential

St. John, J. (2021, October 31). *Can smart solar inverters help keep grid voltages in balance?…*. Canary Media. https://www.canarymedia.com/articles/solar/can-smart-solar-inverters-help-keep-grid-voltages-in-balance

Tietenberg, T. (2009). Reflections—Energy Efficiency Policy: Pipe Dream or Pipeline to the Future? *Review of Environmental Economics and Policy*, *3*(2), 304–320.

Zethmayr, J., & Kolata, D. (2018). The costs and benefits of real-time pricing: An empirical investigation into consumer bills using hourly energy data and prices. *The Electricity Journal*, *31*(2), 50–57.

Zethmayr, J., & Makhija, R. S. (2019). Six unique load shapes: A segmentation analysis of Illinois residential electricity consumers. *The Electricity Journal*, *32*(9), 106643.