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October 15, 2025

BY ELECTRONIC DELIVERY

Bernard Logan, Clerk
Document Control Center
State Corporation Commission
1300 E. Main Street, Tyler Bldg., 1st Fl.
Richmond, VA 23219

Commonwealth of Virginia, ex rel. State Corporation Commission,
In re: Virginia Electric and Power Company's 2025 Updated to the 2024 Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.
Case No. PUR-2025-00184

Dear Mr. Logan:

Please find enclosed for electronic filing in the above-captioned proceeding the 2025 update to the 2024 Integrated Resource Plan (the "2025 IRP Update") of Virginia Electric and Power Company (the "Company") filed pursuant to § 56-597 *et seq*. of the Code of Virginia ("Va. Code") and the Integrated Resource Planning Guidelines adopted by the State Corporation Commission of Virginia ("Commission") in Case No. PUE-2008-00099 ("Guidelines"). As required by the Commission, a reference index is enclosed that identifies the sections of the 2025 IRP Update that comply with the Va. Code, the Guidelines, and the requirements of relevant prior Commission orders.

Please do not hesitate to contact me if you have any questions regarding this filing.

Very truly yours,

/s/ Vishwa B. Link

Vishwa B. Link

Enclosures

cc: William H. Chambliss, Esq.
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Virginia Electric and Power Company's 2025 Update to the 2024 Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Case No. PUR-2025-00184
Docket No. E-100, Sub 214

Filed: October 15, 2025

Order / Guideline	Requirement	2025 IRP Update Section
Va. Code § 56-599 (D)	As part of preparing any integrated resource plan pursuant to this section, each utility shall conduct outreach to engage the public in a stakeholder review process and provide opportunities for the public to contribute information, input, and idea's on the utility's integrated resource plan, including the plan's development methodology, modeling inputs, and assumptions, as well as the ability for the public to make relevant inquiries, to the utility when formulating its integrated resource plan. Each utility shall report its public outreach efforts to the Commission. The stakeholder review process shall include representatives from multiple interest groups, including residential and industrial classes of ratepayers. Each utility shall, at the time of the filing of its integrated resource plan, report on any stakeholder meetings that have occurred prior to the filing date.	**Appendix 1** 2024 IRP Stakeholder Process Report
Guideline (E)	Each filing shall include a five-year action plan that discusses those specific actions currently being taken by the utility to implement the options or activities chosen as appropriate per the IRP.	**Chapter 3.6** The Five-Year Reliability Plan
Guideline (E)	If a utility considers certain information in its IRP to be proprietary or confidential, the utility may so designate, file separately and request such treatment in accordance with the Commission's Rules of Practice and Procedures.	**Not Applicable.**
Guideline (E)	Additionally, by September 1 of each year in which a plan is not required, each utility shall file a narrative summary describing any significant event necessitating a major revision to the most recently filed IRP, including adjustments to the type and size of resources identified. If the utility provides a total system IRP in another jurisdiction by September 1 of the year in which a plan is not required, filing the total system IRP from the other jurisdiction will suffice for purposes of this section.	**The 2025 IRP Update**
Case No. PUR-2020-00035 Final Order at 7, n.25	In future IRPs and updates, the Company shall, at a minimum, include the following sensitivities: (i) high and low PJM energy prices; (ii) high and low PJM capacity prices; (iii) high and low REC prices; (iv) high and low construction costs; (v) high and low fuel prices; (vi) high and low load forecast scenarios; and (vii) the impact of not meeting legislatively mandated energy efficiency savings targets.	**Chapter 5.3** Sensitivity Analyses
Case No. PUR-2020-00035 Final Order at 9	The Commission directs the Company to include in future IRPs and updates the up-to-date reliability analyses of the impacts of retiring traditional fossil generation and adding growing amounts of renewable energy resources on the Company's electric system.	**Chapter 2.3.3** Transmission System Reliability Analyses **Appendix 2D** Transmission System Reliability Analyses
Case No. PUR-2020-00035 Final Order at 9	In the future, the Company should also include one or more plans without [a 970 MW CT] "placeholder" additions to address reliability concerns for comparison purposes and to improve transparency in the Company's planning processes	**Not Applicable.**
Case No. PUR-2020-00035 Final Order at 10	We agree that it is appropriate to model retirements as part of the PLEXOS modeling; however, we will also require the Company, for the time being, to continue to file a separate retirement analysis comparable to the economic analysis performed in this case	**Chapter 5.5** Retirement Analysis
Case No. PUR-2020-00035 Final Order at 11, n.50	Staff recommended and the Company did not object to providing certain capacity-related information in future IRPs and updates, and we so direct as agreed by Staff and the Company. Includes: (i) the most recent PJM Dominion Zone coincident peak forecast; (ii) the most recent PJM Dominion Zone non-coincident peak forecast; (iii) versions of both aforementioned forecasts scaled down to the Dominion load serving entity level; (iv) each Company-owned generation unit interconnected at the transmission-level in the PJM Dominion Zone and the associated nameplate capacity; (v) all Company-owned units that have cleared the PJM capacity market or have capacity performance obligations; (vi) any notification to PJM of the Company's intention to retire or deactivate Company-owned units.	**Appendix 3A** Capacity Information Directed by the SCC
Case No. PUR-2020-00035 Final Order at 11-12 and n.53	In future IRPs and updates, the Company should study and report separately on its summer and winter capacity and energy needs, and its alternative plans' ability to meet those requirements. The Company should also give due consideration to market purchases during the winter from the PJM wholesale market, which remains a summer peaking entity; this consideration should include market purchases from merchant generators located within the Dominion Zone that are not subject to a transmission import capacity constraint.	**Chapter 3.1** Supply-Side Generating Resources **Chapter 5** Expansion Plan Modeling Assumptions and Results **Appendix 5C** Capacity, Energy, and RECs for each Primary Portfolio
Case No. PUR-2020-00035 Final Order at 12	We direct the Company to continue to model energy efficiency targets after 2025	**Chapter 2.1** The Load Forecast
Case No. PUR-2020-00035 Final Order at 14 and n.56	Dominion proposes that future IRPs and updates include a least cost VCEA plan that would meet (i) applicable carbon regulations and (ii) the mandatory RPS Program requirements of the VCEA. For this plan, the Company proposes not to force the model to select any specific resource nor exclude any reasonable resource and allow the model to optimize the accompanying resource plan. Based on the record in this proceeding, we find this proposal to be reasonable at this time. While the Commission recognizes that certain build constraints may be necessary under certain circumstances, the reasonableness of any such build constraints will be subject to Commission review in future proceedings.	**Chapter 5.3** Sensitivity Analyses
Case No. PUR-2020-00035 Final Order at 14-15	The Commission finds that the Company should address environmental justice in future IRPs and updates, as appropriate. As one example, the Company may consider the impact of unit retirement decisions on environmental justice communities or fenceline communities.	**Chapter 6.1** Environmental Justice
Case No. PUR-2020-00035 Final Order at 15-16	The Commission will require Dominion to file an updated bill analysis by plan in future IRPs and updates with the following modifications: • The Company shall provide bill impacts over the next ten years for the least cost VCEA plan, the Company's preferred plan, and any additional plans presented, including residential, small general service and large general service customer bills. Each update shall include an additional year of projections beyond 2030 as each year passes and should consistently be compared back to the actual bill as of May 1, 2020. • As proposed by Staff, the Company shall use class allocation factors and projected sales recently used to set rate adjustment clause rates in the bill analysis. • In addition to projections, the analysis shall include actual bill impact information as each year passes. For example, in the 2021 update filing, the Company would include the actual bill information as of December 31, 2020 in the bill analysis.	**Chapter 4.2.1** Virginia Bill Analysis **Appendix 4A** Virginia Bill Analysis
Case No. PUE-2016-00049 Final Order at 3 Case No. PUE-2015-00035 Final Order at 18	Dominion shall continue to comply with all requirements directed in prior IRP orders, including the requirement to include an index that identifies the specific location(s) within the IRP that complies with each such requirement.	**2025 IRP Update** Reference Index

Table of Contents

List of Appendices

Appendix 3E: Description of Active DSM Programs

Appendix 3F: Description of Recently Approved DSM Programs

Appendix 4A: Virginia Bill Analysis[1]

Appendix 4B: North Carolina Bill Analysis[2]

Appendix 5A: Environmental Regulations

Appendix 5B: Cost Assumptions

- 5B-1: Least Cost VCEA Compliant Price Forecast (Nominal $)
- 5B-2: Commodity Price Forecast, Natural Gas
- 5B-3: Commodity Price Forecast, Natural Gas
- 5B-4: Commodity Price Forecast, Coal (FOB)
- 5B-5: Commodity Price Forecast, Oil
- 5B-6: Commodity Price Forecast, On-Peak Power Price
- 5B-7: Commodity Price Forecast, Off-Peak Power Price
- 5B-8: Commodity Price Forecast, PJM Tier 1 RECs
- 5B-9: Commodity Price Forecast, VA REC
- 5B-10: Commodity Price Forecast, PJM RTO Capacity ($/kW-yr)
- 5B-11: Commodity Price Forecast, PJM RTO Capacity ($/MW-day)
- 5B-12: Commodity Price Forecast, DOM Zone Capacity ($/kW-yr)
- 5B-13: Commodity Price Forecast, DOM Zone Capacity ($/MW-day)
- 5B-14: Commodity Price Forecast, SO_2 Emission Allowances ($/Ton)
- 5B-15: Commodity Price Forecast, NO_x Emission Allowances
- 5B-16: Commodity Price Forecast, NO_x Emission Allowances (CSAPR Annual)
- 5B-17: Commodity Price Forecast, Federal CO_2 ($/Ton)

Appendix 5C: Capacity, Energy, and RECs for the Primary Portfolios

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[1] Filed in Virginia only.

[2] Filed in North Carolina only.

Executive Summary: An Integrated Resource Plan Update that Continues to Focus Upon Meeting Customer Needs

Virginia Electric and Power Company ("Dominion Energy" or the "Company"), headquartered in Richmond, Virginia, is a vertically integrated utility that operates generation, transmission, and distribution systems to serve approximately 2.8 million electric customers located across approximately 30,000 square miles of Virginia and North Carolina.

The Company's mission continues to be providing reliable, affordable, and increasingly clean energy to power our customers every day. Dominion Energy has a long record of operating its generation, transmission, and distribution systems reliably and affordably. Our customers have uninterrupted power 99.98% of the time, excluding major storms. Our rates have remained consistently below the national average (residential rates are currently approximately 9% below the national average) and have increased less than the general rate of inflation since 2008. And the Company is a nationally recognized leader in the development of clean energy resources including nuclear, solar, energy storage, and offshore wind.

Dominion Energy's Integrated Resource Plan ("IRP") is a reliability planning document filed annually with the Virginia State Corporation Commission ("SCC") and the North Carolina Utilities Commission ("NCUC"). In even numbered years, the Company files a comprehensive IRP. In odd numbered years, such as 2025, the Company files an interim update. The IRP outlines potential portfolios to meet customers' long-term energy needs while complying with regulatory, environmental, and public policy requirements and ensuring reliable and affordable electric service. The IRP represents a "snapshot in time," incorporating current technologies, market conditions, and projected demand.

This year's IRP is an interim update to the Company's 2024 IRP (the "2025 IRP Update"). The 2025 IRP Update informs the SCC, NCUC, and stakeholders of significant developments since the comprehensive 2024 IRP. Such developments include the following:

- Confirmation of significant demand growth projections for the Dominion Energy delivery Zone of PJM ("DOM Zone"), both within Dominion Energy's service territory and, more significantly, the remainder of DOM Zone, consistent with the 2024 IRP load forecast;

- Updated planning portfolios required to meet forecasted demand and the need for adequate and reliable capacity and energy resources, including during severe weather events, that are incrementally more robust and diverse than the 2024 IRP portfolios;

- A shift to a 20-year resource planning timeframe, consistent with PJM's new planning horizon; and

- The potential impact of evolving market conditions and changing federal environmental and fiscal policies on the Company's resource planning.

The foundation of Dominion Energy's resource planning process is its obligation to serve all customers in its retail service territory as well as transmission customers in the Company's delivery zone within PJM where distribution service is provided by electric cooperative or municipal electric companies. Demand is forecasted to increase 6.3% annually over the next decade and more than double by 2045 in the DOM Zone. An "all of the above" approach that includes significant investment in new generation resources, an expanded and improved transmission and distribution grid, and continued focus on energy efficiency programs will be required to satisfy these obligations.

Constraints within PJM continue to underscore the need for additional power generation and electric transmission resources within the Company's delivery zone, as well as the value of generation resources that can produce energy on demand, most notably at times of peak need. As with the 2024 IRP, this 2025 IRP Update recognizes limits on the ability to import power to the DOM Zone. An over-reliance on imported power creates reliability and price risks for our customers, particularly as load continues to grow throughout PJM and conventional generation resources have retired and will continue to retire across PJM for economic and public policy reasons. Energy security has never been more important for the well-being of the communities that we serve given the central role that electricity plays in modern life and the increased demand for that service.

PJM holds annual capacity auctions to attempt to ensure that supply resources are adequate to meet demand at peak times (typically when it is very hot or very cold), including a safety reserve margin. The most recent capacity auction in July 2025 yielded the second-highest capacity price ever for the DOM Zone, which has the highest forecasted load growth of any area within PJM. Factors driving higher capacity values for a given area include high demand, fewer resources to meet the demand and a restricted ability to import power. The DOM Zone cleared just over $329/MW-day for the 2026/2027 Delivery Year[1]. The 2026/2027 capacity auction results signal continued resource adequacy concerns for not only the DOM Zone but the entire PJM footprint.

Against that backdrop, this 2025 IRP Update presents multiple potential portfolios (the "Portfolios") the Company could implement to meet our customers' capacity and energy needs over the next 20 years. As with all forecasts, near-term resource planning is more certain than longer-term planning, particularly as emerging generation technologies are being explored. The statutory scope of the IRP does not include approval of any specific resource or portfolio of resources. Resource approvals are considered by the Commission in separate regulatory proceedings.

As always, the Company remains committed to working with stakeholders in its planning processes. In 2023, the Virginia General Assembly enacted legislation that directed Dominion Energy, when preparing its IRP, to "engage the public in a stakeholder review process" and detailed

[1] This is the price cap negotiated through an agreement between PJM and the office of Pennsylvania Governor Josh Shapiro.

specific actions the Company must take in implementing this process.[2] The Company recognizes the importance of continued engagement to promote transparency and inclusivity in its energy planning and created the 2025 interim update stakeholder process based on lessons learned from the 2024 process. The Company offered targeted opportunities for input on planning assumptions, modeling methodologies, and emerging policy considerations through an updated Stakeholder Input Case.

In summary, the 2025 IRP Update confirms the need to address significant demand growth through resource adequacy across all functions of the utility, the paramount priority of service reliability, and the importance of maintaining affordable customer rates.

[2] Va. Code § 56-599 D.

The 2025 IRP Update

In accordance with § 56-599 of the Code of Virginia, electric utilities shall file an integrated resource plan ("IRP") in each year immediately preceding the year the utility is subject to a biennial review of rates (*i.e.*, a "full" IRP). Electric utilities shall then file an annual update to the "full" IRP in each year that the utility is subject to review of rates (*i.e.*, an "IRP update"). The intent of an IRP update is to provide a "narrative summary describing any significant event necessitating a major revision to the most recently filed [full] IRP, including adjustments to the type and size of resources identified."[3]

On October 15, 2024, the Company filed a "full" IRP (the "2024 IRP") with the Virginia State Corporation Commission ("SCC") (Case No. PUR-2024-00184) and the North Carolina Utilities Commission ("NCUC") (Docket No. E-100, SUB 204). On July 7, 2025, the NCUC issued its Order accepting the 2024 IRP and finding it reasonable for planning purposes. The NCUC Order also included requirements for additional information to be included in the "2025 IRP Update and all future IRPs." On July 15, 2025, the SCC issued its Final Order on the 2024 IRP, finding it legally sufficient under the applicable statutes and regulations and setting forth information for the Company to include in "future IRP filings."

The Company files this update to the 2024 IRP ("2025 IRP Update") with the SCC and the NCUC consistent with all relevant Virginia and North Carolina laws, regulations and Commission orders and includes information on significant events necessitating major revisions occurring after the 2024 IRP was filed. The 2025 IRP Update presents potential pathways to meeting customers' energy and capacity needs while maintaining reliability and affordability over the next 20 years. Like the 2024 IRP, this 2025 IRP Update is meant for use as a long-term planning document based on a "snapshot in time" of current technologies, market information, and projections. IRPs and IRP Updates are not a request to approve any specific resource or Portfolio but rather to assess their reasonableness for long-term planning purposes.

In this 2025 IRP Update, the Company presents three primary resource Portfolios to meet customers' future needs under different scenarios and designed using constraint-based least-cost planning techniques. The Primary Portfolios incorporate the requirements of the Virginia Clean Economy Act of 2020 ("VCEA") and current federal environmental rules impacting carbon-emitting generation units. Given continued technological development and evolving federal and state laws over an extended 20-year period, the Company's path forward is likely a combination of these Portfolios as well as incorporation of new technologies as they become commercially available. In addition to the three Primary Portfolios, this 2025 IRP Update also includes one Secondary Portfolio and several sensitivities. These additional scenarios show how potential outcomes change when certain modeling assumptions are updated.

[3] Integrated Resource Planning Guidelines adopted by the Commission in Case No. PUE-2008-00099, Guideline (E), https://www.scc.virginia.gov/media/sccvirginiagov-home/regulated-industries/utility-regulation/responsibilities/guidance-documents/irp.pdf.

Chapter 1. Commitment to Reliability

We have an obligation to serve: As a regulated electric utility, Dominion Energy has an obligation to serve all customers within its service territory, and we are committed to providing our customers with reliable, affordable, and increasingly clean energy. The Company operates generation, transmission, and distribution systems to serve its customers. As the transmission operator, Dominion Energy is also responsible for serving local distribution companies - such as electric cooperatives and municipal electric companies - who then serve their own customers. We have consistently achieved a high degree of reliability, demonstrating that reliability is our longstanding priority.

Dominion Energy, as a regulated public electric utility, has an obligation to reliably serve all customers who request service within its service territory. Practically, this means that the Company must have sufficient resources and reserves to be able to instantaneously respond to hourly, daily, and seasonal spikes in customer demand against the backdrop of a steadily growing energy need in the Company's service territory and within the region. As a vertically integrated utility by state law, the Company operates all three aspects of electric utility service: generation, transmission, and distribution systems to serve customers. The Company's service territory is served by the Dominion Energy Load Serving Entity ("DOM LSE").

Dominion Energy's generation portfolio consists of 20,571 megawatts ("MW") of generation capacity, including approximately 1,343 MW of resources owned by third parties from which the Company purchases the output through power purchase agreements ("PPAs"). The Company's power generation resources create electricity from a primary source of energy, including nuclear, natural gas, coal, biomass, solar, wind, or water. The Company's demand-side management ("DSM") portfolio consists of energy efficiency and demand response programs in Virginia and North Carolina. The DSM portfolio offers voluntary energy conservation programs for customers that are designed to reduce demand during peak periods.

Dominion Energy also owns and operates a portion of the transmission system (also known as the bulk power system) that moves large amounts of electricity over long distances. This transmission system is responsible for providing service (i) for redelivery to the Company's retail customers in Virginia and North Carolina; (ii) to Old Dominion Electric Cooperative ("ODEC"), Northern Virginia Electric Cooperative ("NOVEC"), Central Virginia Electric Cooperative, and Virginia Municipal Electric Association for redelivery to their retail customers in Virginia; and, (iii) to North Carolina Electric Membership Corporation and North Carolina Eastern Municipal Power Agency for redelivery to their customers in North Carolina (collectively, this region is referred to as the DOM Zone and encompasses the DOM LSE as well as the territories of other LSEs). Dominion Energy owns approximately 6,800 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV in Virginia, North Carolina, and West Virginia. The DOM Zone is part of PJM,[4] which encompasses all or part of 13 states, as well as the larger Eastern Interconnection transmission grid, meaning the transmission system is interconnected, directly or indirectly, with other transmission systems in the United States and Canada between the Rocky Mountains and the Atlantic Coast, except for Quebec and most of Texas. The transmission systems in the Eastern Interconnection are dependent on each other for moving bulk power through the transmission system and for reliability support. Accordingly, as a transmission owner, Dominion Energy is not only responsible for reliable service to its own transmission customers, but also for the integrity of the Eastern Interconnect as a whole. Additionally, Dominion Energy owns approximately 60,600 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia and North Carolina. Distribution lines deliver power from substations to individual neighborhoods, homes, and businesses.

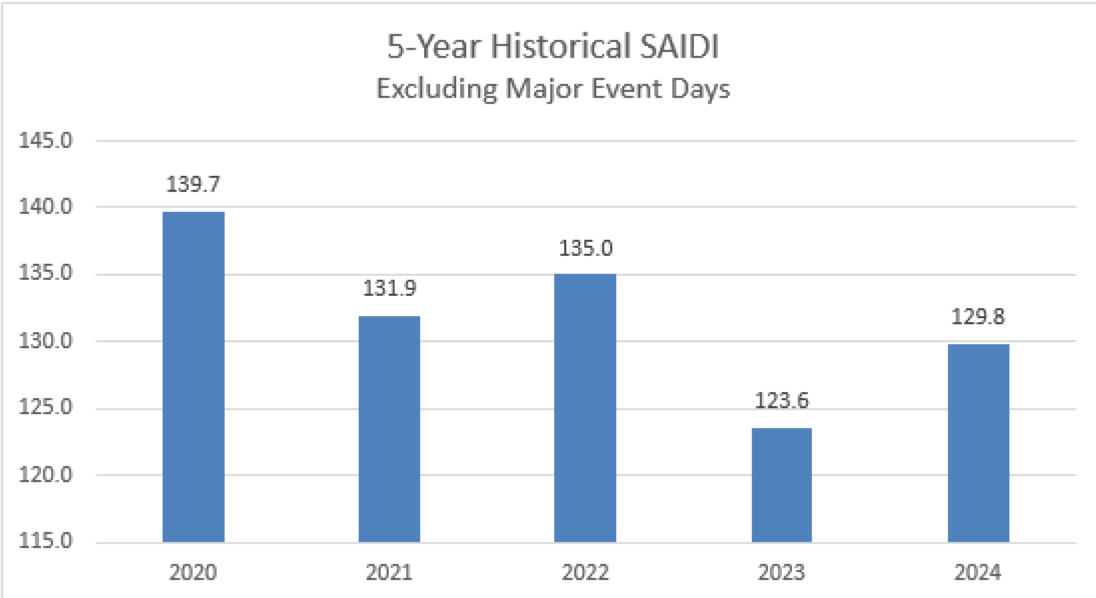
Dominion Energy must plan and operate its three functional aspects to ensure reliability for all customers. For power generation, reliability requires a sufficient number of generation resources and resource diversity to avoid over-reliance on any one energy source, along with dependable fuel supplies. The generation portfolio must be able to meet both real-time demand for electricity and PJM reserve requirements (*i.e.,* the need to have sufficient generation on standby). While Dominion Energy operates a diverse portfolio of resources and engages in necessary market purchases to serve customers' energy and capacity needs, the ability to purchase power is finite, and over-reliance on market purchases will create risks to both reliabilty and affordability.

The reliability of the transmission system is dependent on a number of factors, with North American Electric Reliability Corporation ("NERC") Reliability Standards being one of the major drivers. Correctly siting, building, and utilizing transmission lines allows customers to be confident they will reliably receive energy at their homes and businesses. NERC Reliability Standards set baseline thresholds to ensure that the transmission system is reliably planned and operated. The Regional Transmission Expansion Plan ("RTEP"), managed by PJM for its members, allows for efficient and reliable transmission planning.

Distribution reliability entails preventing local power outages whenever possible and restoring power quickly when it is not. Two industry metrics generally track utility companies' distribution reliability: System Average Interruption Duration Index ("$SAIDI_{EX}$") measures how many minutes, on average, a customer was without power in a given year, excluding major storms; System Average Interruption Frequency Index measures the average number of times a customer was without power in a given year. As shown in Figure 1.1, Dominion Energy has a commendable track record of reliability for its Virginia and North Carolina territory over the last five years, demonstrating that, excluding major storms, customers have uninterrupted electric service 99.98% of the time throughout the year. This record reflects both the Company's strengths as an operator of power distribution assets and the Company's investments in the reliability of its distribution system.

[4] PJM is currently responsible for ensuring the reliability and coordinating the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Figure 1.1: SAIDI_{EX} in Dominion Energy's Service Territory (minutes)



Dominion Energy serves 2.5 million residential customers and over 250,000 business customers who rely on the Company to power their every day. We are tasked with keeping the lights on for some of the most critical facilities in the United States, as well as building and maintaining important infrastructure for the reliability of the largest data center market in the world. In the next section, we will address some of the current challenges to maintaining reliability.

Chapter 2. Current Challenges to Reliability

In recent years, Dominion Energy has experienced consistent load growth, which is expected to significantly outpace the average growth in PJM. The growth is driven in large part by the digitization of the economy served by data centers.

Spikes in demand during winter storms and heat waves have highlighted the vulnerability of the electric grid. To mitigate these risks and ensure reliability, PJM executed a capacity market reform tying the value of energy generators to their contribution at the time of need. Challenges to reliability associated with a substantially increasing proportion of renewable generators on the grid need to be addressed through an appropriate mix of generation resources, expansion and enhancement of the transmission system, and distribution grid transformation.

2.1 The Load Forecast

The load forecasts and methodologies for the 2025 IRP Update are largely consistent with the 2024 IRP (see Appendix 2A of the 2024 IRP). The load forecast continues to show growth as it has over the last several years (Figure 2.1.3). The two changes to highlight from the 2024 IRP are focused on the growth within the DOM Zone but outside of the DOM LSE and an update to how behind-the-meter ("BTM") is adjusted for in modeling, as described below.

Dominion Energy uses load forecasts to determine customers' future energy and capacity needs and to plan to meet those needs. The 2025 IRP Update presents two load forecasts: 1) the 2025 PJM Derived Load Forecast, and 2) the 2025 Company Load Forecast. Both continue to show significant growth. At the SCC's directive, the Company used the 2025 PJM Derived Load Forecast in the development of all Portfolios. Data underlying the updated load forecasts for the 2025 IRP Update is presented in Appendix 2B.

The 2025 PJM Load Forecast continues to show significant growth over the next 20 years

The entire PJM region is experiencing unprecedented load growth, and the DOM Zone continues to be one of the fastest growing zones in PJM. On January 23, 2025, the DOM Zone set a new all-time record peak of 24,678 MW. Figure 2.1.1 presents the 2025 PJM Load Forecast for coincident peak[5] for the DOM Zone. Overall, the 20-year compound annual growth rate ("CAGR")[6] for the DOM Zone is 4.1%.

The DOM Zone is comprised of the DOM LSE and non-DOM LSE portions ("Residual DOM Zone"), and Figure 2.1.1 depicts the growth rates for each segment. This highlights the differences

[5] In this context, coincident peak is defined as the demand on the DOM Zone system that occurs during the PJM RTO peak, in contrast to non-coincident peak, which would be the peak demand for the LSE.

[6] CAGR is the average growth rate, in this case growth in load, over a period of time.

in the growth expected by these two parts of the DOM Zone. While the whole of the DOM Zone peak demand is growing at a CAGR of 4.1% over the 20-year forecast horizon, the Residual DOM Zone (mainly comprised of co-operative load) is growing at an even faster pace with a forecasted 7.4% CAGR over the next 20-years. The DOM LSE is forecast to experience a CAGR of 2.5% over that same time period.

Figure 2.1.1: 2025 PJM Load Forecast for Coincident Peak for the DOM Zone

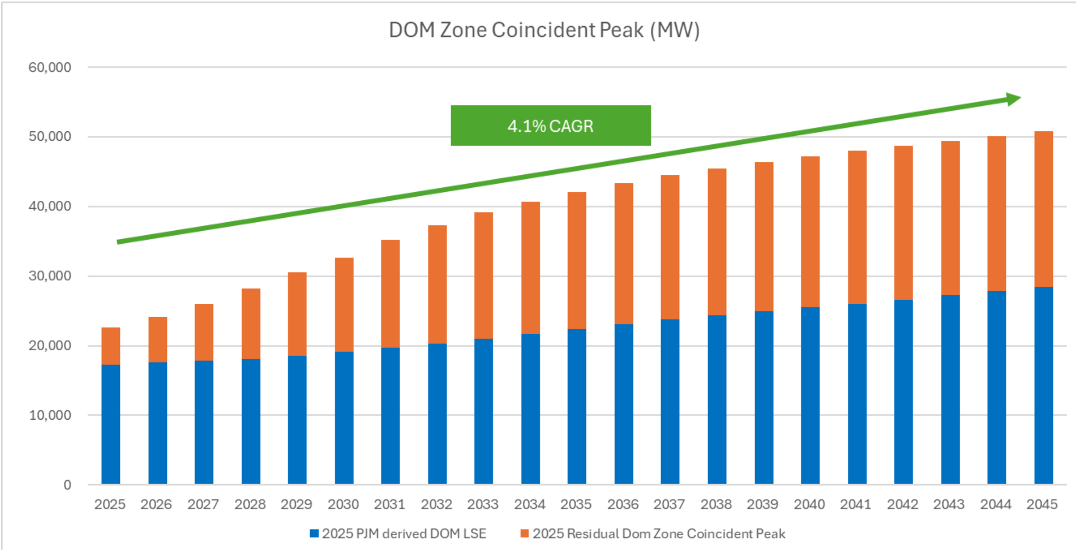


Figure 2.1.2 presents the 2025 PJM Load Forecast for energy for the DOM Zone. Overall, the 20-year CAGR for the DOM Zone is 5.3%; this is comprised of the DOM LSE, which is forecast to grow at a 3.5% CAGR, and the Residual DOM Zone portion, which is forecasted to experience an 8.5% CAGR. Like the load forecast for the coincident peak, the annual energy for the Residual DOM Zone portion is experiencing a faster rate of growth compared to DOM LSE.

Figure 2.1.2: 2025 PJM Load Forecast for Annual Energy

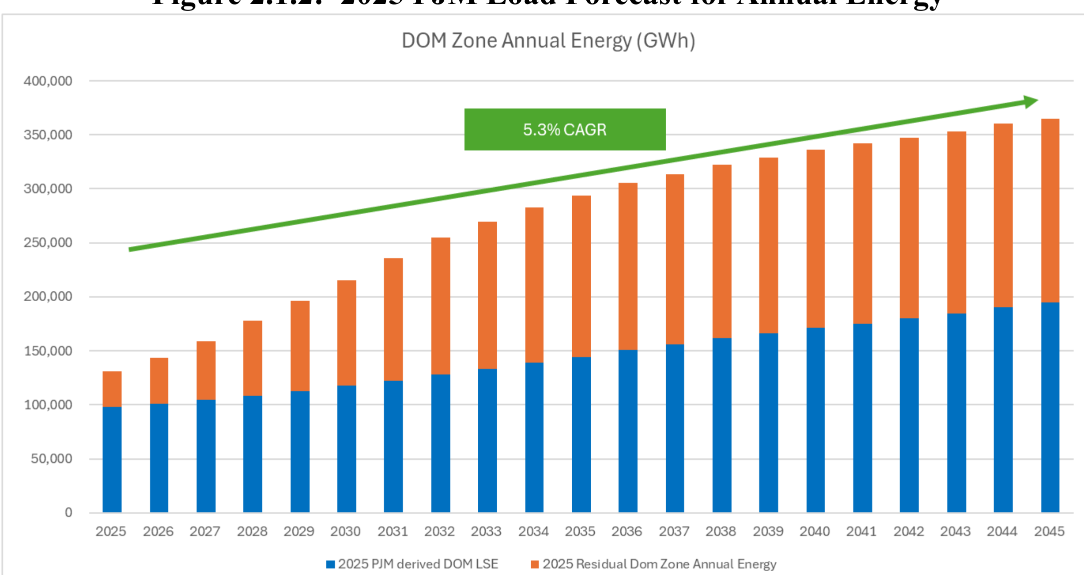


Figure 2.1.3 presents the year-over-year changes in PJM's DOM Zone load forecasts. PJM's 2025 Load Forecast for the DOM Zone increased in the outer years for the fourth year in a row relative to the prior year's forecast. Increases in the data center load forecast continue to be a key driver for the year-over-year changes in the PJM DOM Zone load forecast.

Figure 2.1.3: PJM Summer Peak Forecast Comparison (2021 to 2025) for the DOM Zone

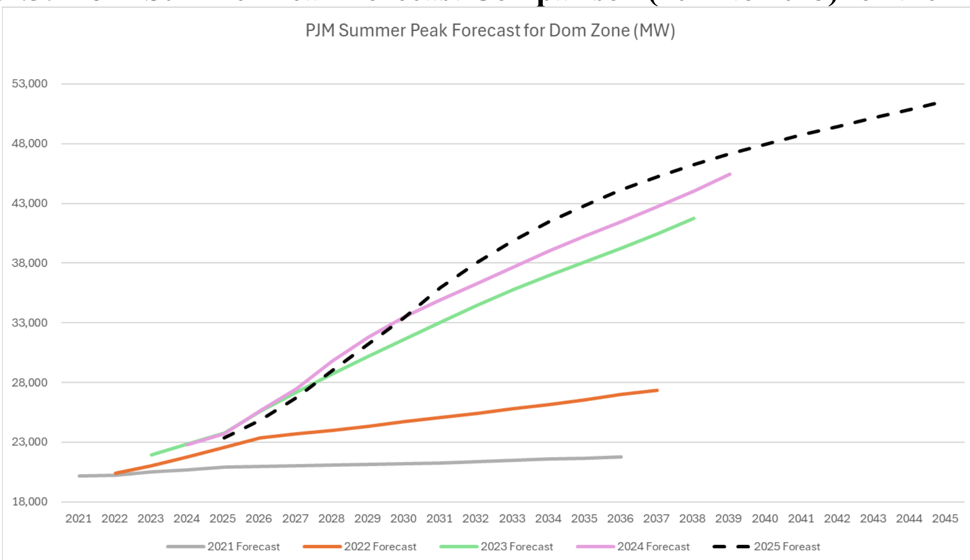
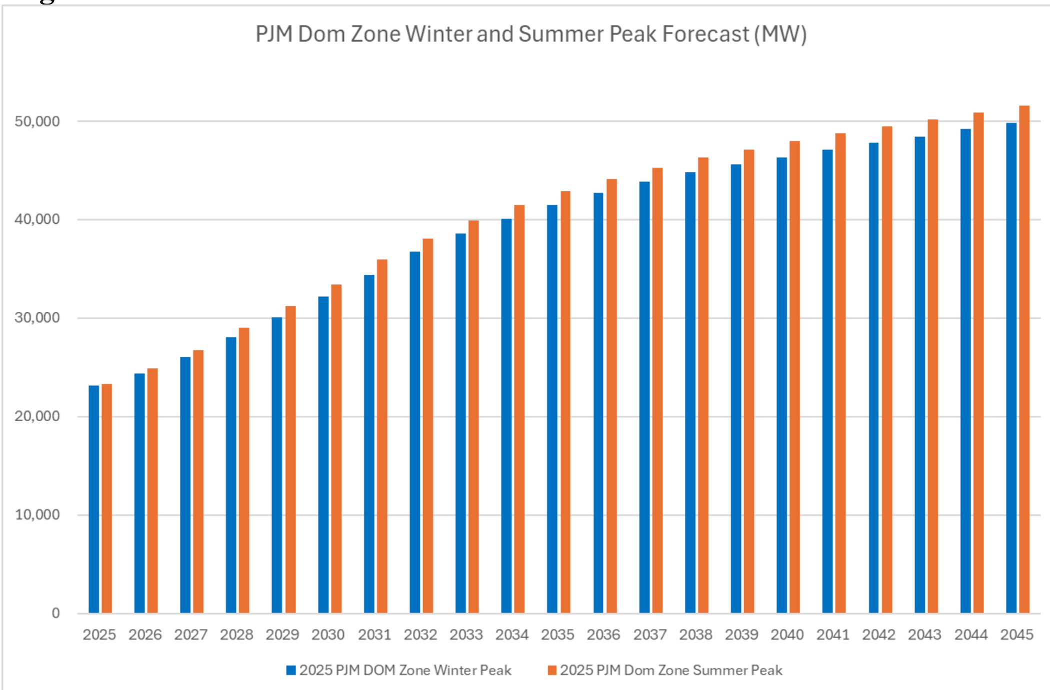


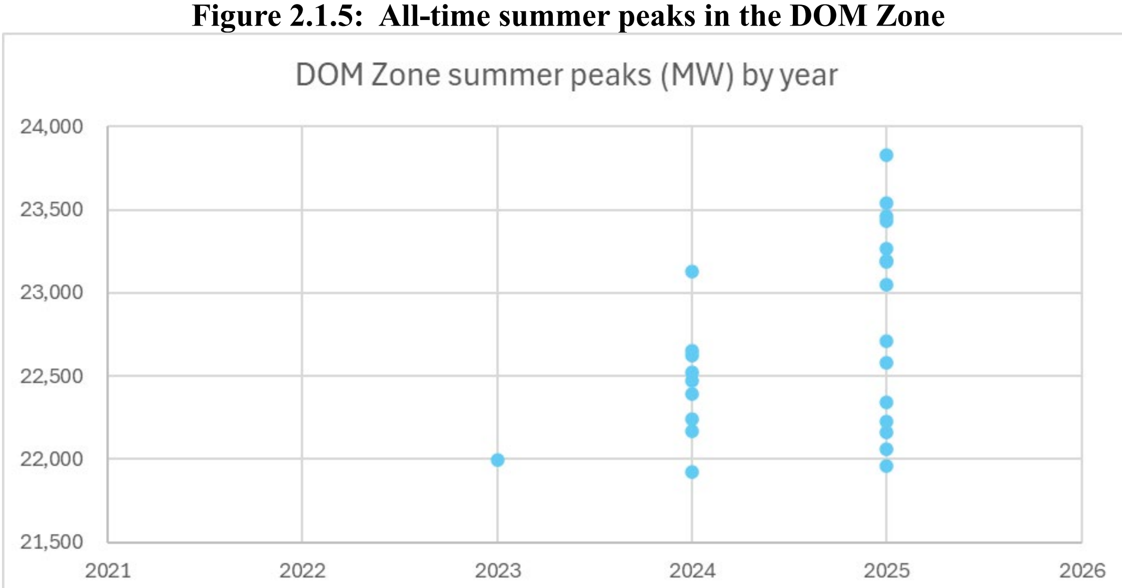
Figure 2.1.4 shows the PJM DOM Zone forecasted non-coincident peaks split out by winter and summer. Over the 20-year forecast horizon, winter and summer peaks are projected to grow by 3.9% and 4.0%, respectively, on a compound annual basis. Forecasted peaks assume normal weather, meaning that extreme weather events could cause actual peaks to greatly exceed the forecast in any given year and for sustained periods. The Company must plan its generation to meet customers' needs in extreme weather events, not just normal weather. See Chapter 5.4 for additional discussion of extreme weather.

Figure 2.1.4: PJM DOM Zone Winter and Summer Peak Demand Forecast[7]



As shown in Figure 2.1.5 below, all but one of the top 25 all-time summer peaks in the DOM Zone have been set in the last two years. Recent system peaks in the DOM Zone have been occurring in winter mornings and summer evenings, when renewable output is generally less available. A diverse portfolio of resources will be needed to ensure the Company can meet customers' needs at all hours of the day, including these peak times during both winter and summer.

Figure 2.1.5: All-time summer peaks in the DOM Zone



[7] https://pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx.

PJM Derived Load Forecast for the DOM LSE

As with the 2024 IRP, to properly use the PJM Load Forecast for modeling purposes, Dominion Energy converted that forecast to the DOM LSE level. The Company refers to this load forecast as the 2025 PJM Derived Load Forecast. The methods used to create the PJM Derived Load Forecast remain largely the same from prior IRPs and are described in detail in the 2024 IRP.

One update this year is how BTM is adjusted for modeling purposes. Because the Company models new BTM distributed energy resources ("DER") as supply side resources, a final adjustment is needed for PLEXOS modeling. The final IRP modeling input reverses a downward forecast adjustment made by PJM to account for new BTM DER generation. By adding this load back, the Company avoids a double count of the energy from new BTM DER resources. Note that the graphs and figures below do not include this adjustment and are reflective of predicted system load at the PJM meter.

Overall, the 2025 PJM Derived Load Forecast anticipates a 2.5% and 3.5% CAGR for the DOM LSE summer non-coincident peak ("NCP") demand and annual energy, respectively, over the Planning Period (*i.e.*, 2025-2045). Over the same period, the 2025 Company Load Forecast, which is discussed in the next section, predicts a 2.3% and 3.3% CAGR for the DOM LSE summer non-coincident peak demand and annual energy, respectively. Forecasts for both energy (MWh) and peaks (MW) are presented. As shown in Figure 2.1.6 below, the 2025 PJM Derived Load Forecast coincident peak is very similar to the 2024 PJM Derived Load Forecast. Figure 2.1.7 also shows that the 2025 PJM Derived Load Forecast for energy is slightly lower than the 2024 PJM Derived Load Forecast. Figures 2.1.6 and 2.1.7 show a 15-year timeframe for 2024 and a 20-year timeframe for 2025 as consistent with the planning periods conducted for the 2024 IRP and 2025 IRP Update, respectively.

Figure 2.1.6: 2025 vs 2024 PJM Derived Load Forecast - Coincident Peak

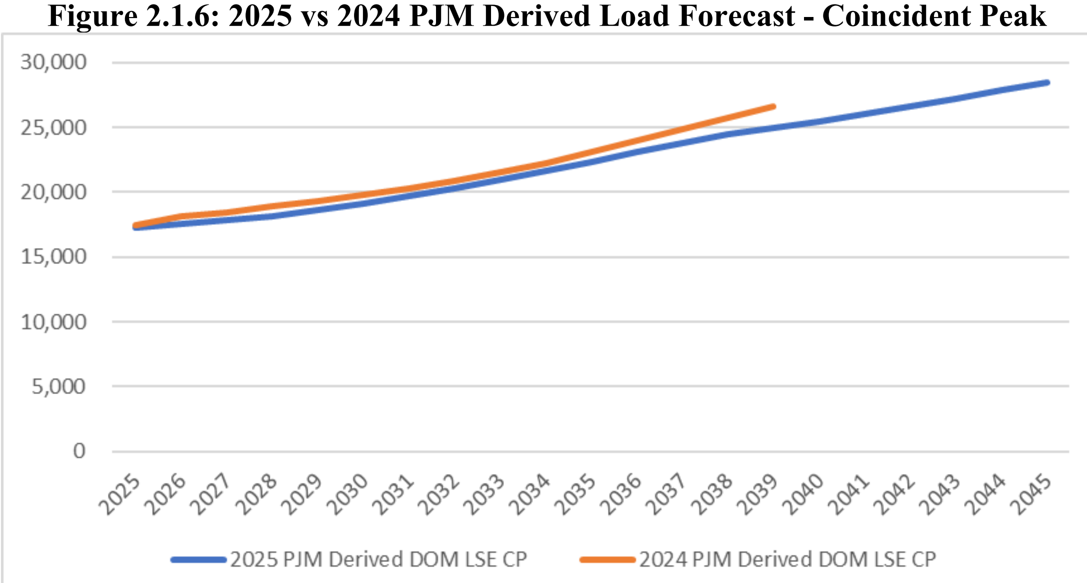
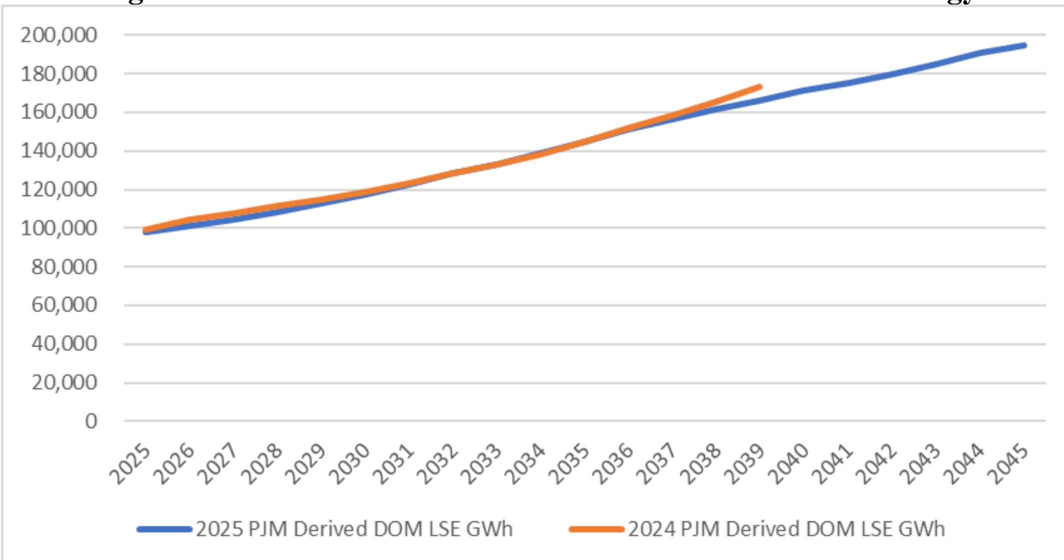


Figure 2.1.7: 2025 vs 2024 PJM Derived Load Forecast – Energy



Company Load Forecast

The 2025 IRP Update also includes the Company's Load Forecast, which is an internally developed peak demand and energy forecast for the DOM LSE. The Company Load Forecast and 2025 PJM Derived Load Forecast are in general alignment, as shown in Figure 2.1.8.

Figure 2.1.8: 2025 Company Load Forecast vs. PJM Derived Load Forecast (GWh)

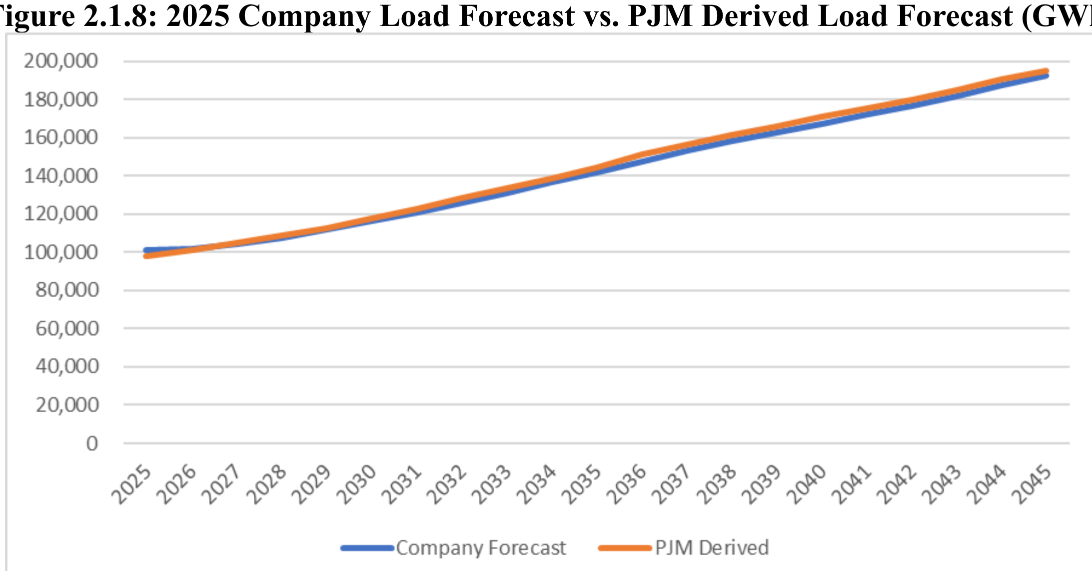


Figure 2.1.9 below presents the 2025 Company Load Forecast NCP and annual energy.

Figure 2.1.9: 2025 Company Load Forecast

Year	Dom LSE Summer Peak Forecast (NCP) (MW)	Dom LSE Energy Forecast (GWh)
2025	18,303	101,122
2026	18,470	101,493
2027	18,707	104,327
2028	19,232	107,708
2029	19,370	111,767
2030	19,898	116,297
2031	20,471	121,050
2032	21,133	126,162
2033	21,710	131,188
2034	22,467	136,327
2035	22,930	141,726
2036	23,643	147,597
2037	24,370	152,936
2038	24,910	158,328
2039	25,421	162,555
2040	25,953	167,258
2041	26,570	171,844
2042	27,152	176,820
2043	27,823	181,918
2044	28,237	187,443
2045	28,963	192,423

Electric Vehicle Forecast

Dominion Energy's Company Load Forecast includes an adjustment to sales, energy, and peak demand to account for future incremental electric vehicle ("EV") load. Figure 2.1.10 below shows the EV contribution to peak and energy forecast, respectively. Notably, the EV forecast was not updated after the Federal Tax Bill was passed, which could impact the pace of EV adoption; future IRPs will continue to examine this issue.

Figure 2.1.10: Electric Vehicle Contribution to Peak Demand and Annual Energy Forecast

Year	EV Contribution to Peak (MW)	EV Annual Energy (GWh)
2025	25	135
2026	55	299
2027	88	486
2028	125	695
2029	167	926
2030	222	1,234
2031	287	1,599
2032	359	2,005
2033	435	2,424
2034	515	2,878
2035	601	3,366
2036	691	3,895
2037	785	4,424
2038	882	4,982
2039	982	5,560
2040	1,081	6,163
2041	1,178	6,729
2042	1,274	7,302
2043	1,366	7,853
2044	1,460	8,415
2045	1,546	8,904

Energy Efficiency Adjustment to DOM LSE Load Forecast

DSM programs, including energy efficiency ("EE") and demand response programs, are expected to save energy and reduce capacity needs. Annually, the Company prepares a DSM forecast that reduces overall projected demand and energy in the DOM LSE. The incremental SCC-approved DSM program participation is subsequently subtracted from the Company's overall load forecast to reflect the lower energy and demand. The EE adjustment is consistent with SCC-directed EE savings targets approved in Case No. PUR-2023-00227 (*i.e.*, 3%, 4%, and 5% of 2019 jurisdictional sales for 2026, 2027, and 2028, respectively), and continued increases in energy savings for 2029-2045.

Figures 2.1.11 and 2.1.12 identify the specific EE energy and coincidental capacity adjustments to the load forecasts used in this 2025 IRP Update, respectively. Values shown are at the utility generator and adjusted for line losses. In the values below, the EE adjustment includes savings generated from the Company's voltage optimization ("VO") program. These energy savings are excluded from the EE adjustment used in the PJM Derived Load Forecast, since the Company provided the VO savings as part of a Large Load Adjustment to PJM. The VO savings are therefore embedded in the PJM DOM Zone forecast.

Figure 2.1.11: EE Energy Forecast Adjustment (GWh)

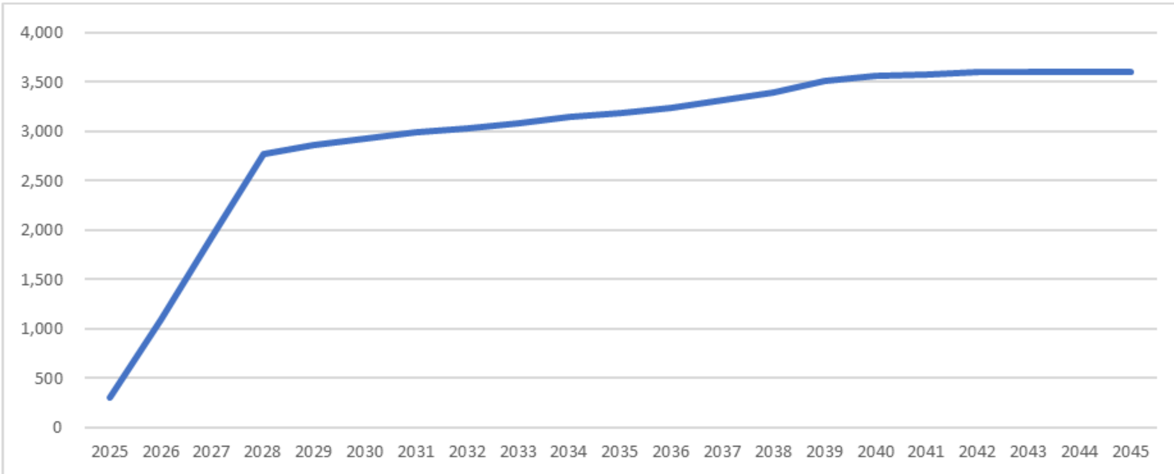
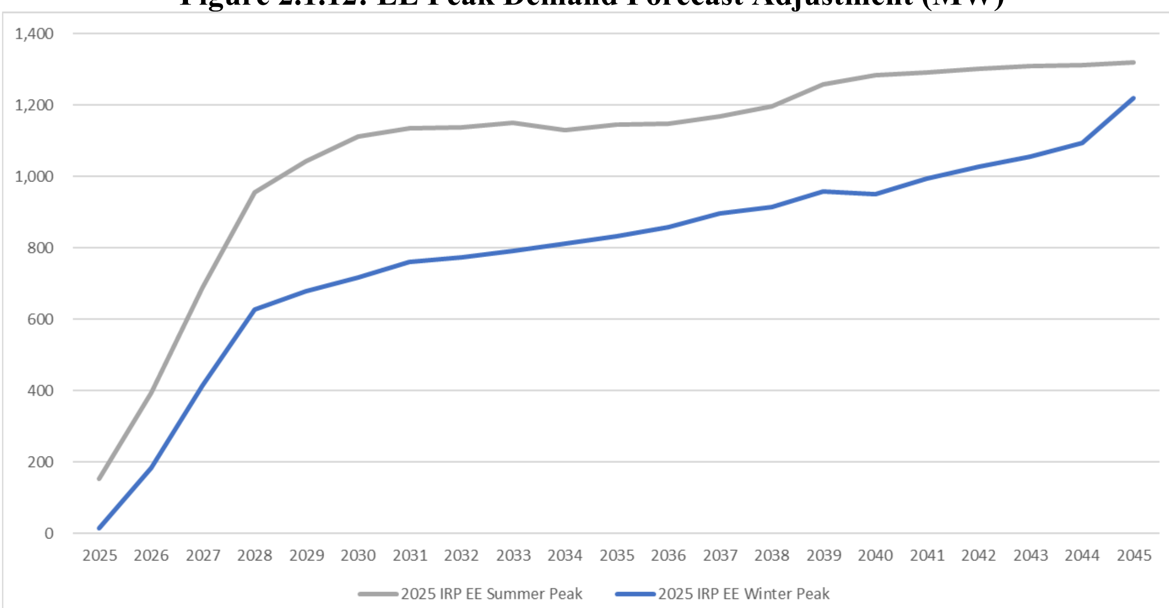


Figure 2.1.12: EE Peak Demand Forecast Adjustment (MW)



Retail Choice Adjustment to DOM LSE Load Forecast

The load forecasts in the 2025 IRP Update include a downward adjustment for Choice Customers.[8] The method to develop the retail choice adjustment remains largely the same from prior IRPs and is described in detail in the 2024 IRP.

[8] Va. Code § 56-577 permits customers who meet certain eligibility requirements to purchase electric energy from a licensed entity other than the utility; it also governs the return of choice customers.

Figure 2.1.13 below identifies the Choice Customer peak demand and energy forecast adjustment in the 2025 IRP Update. The values in Figure 2.1.13 represent non-data center customers only, as data center customers included in the forecast already exclude choice load.

Figure 2.1.13: Retail Choice Annual Adjustment for each year 2025-2045

Year	Estimated Retail Choice Sales (GWh)	Estimated Retail Choice Summer CP (MW)
2025	3,109	540
2026-2045	3,119	540

Due to the uncertain nature of customer migration in or out of Choice, the Company does not attempt to forecast incremental changes to the Retail Choice Adjustment over the forecast period. Instead, the Company only adjusts for customers that have notified the Company of their intention to either leave for, or return from, purchasing generation service through a competitive service provider. It should be noted that Choice Customers have the option to return to the system after a five-year stayout (and in some circumstances more quickly). There are few, if any, generation resources that can be developed, permitted, and constructed in five years or less.

Data center load in the DOM Zone and DOM LSE

As noted in prior IRPs, the Company has extensive experience serving data center customers for over a decade. Northern Virginia continues to be the largest data center market in the world and is larger than the next five largest U.S. data center markets combined.[9] In addition to Northern Virginia, the data center industry is now expanding throughout additional areas within the Company's service territory and the DOM Zone.

The Company has connected six new data center campuses in 2025[10] as of October 1st, with an ultimate capacity of 456 MW. The Company expects to connect two additional data center campuses by the end of the year, for a total of 8 new data center campus connects, with an ultimate capacity of 561 MW in 2025. Given the demand from data centers locating in the DOM Zone, the Company is forecasting significant growth into the future.

The Company provided a data center load forecast to PJM in October 2024, which then reviewed and verified the information provided before incorporating it into PJM's own forecast published January 24, 2025, which is the version used for this 2025 IRP Update. See Appendix 2A of the 2024 IRP for details on the methodology used to develop the data center forecast submitted to PJM.

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[9] North America Data Center Report, North America Year-end 2024, JLL.

[10] Since 2013, the Company has connected on average 15 data center connections (*i.e.*, data center campuses) per year. In 2024, the Company connected 15 data center campuses with an ultimate capacity of 977 MW.

Figure 2.1.14 illustrates customer contracts executed as of July 2025.[11] These contracts are broken into (i) Engineering Letters of Authorization ("ELOA"), (ii) Construction Letters of Authorization ("CLOA"), and (iii) Electric Service Agreements ("ESA"). As a customer moves from (i) to (iii), the financial commitment and obligation by the customer increases. The graph shows the continued growth from executed ESAs through 2038 and support for growth beyond that from the projects currently under construction (CLOAs). See Appendix 2A of the 2024 IRP for additional details about the three types of contracts.

Figure 2.1.14: Customer Contracts Executed, as of July 2025

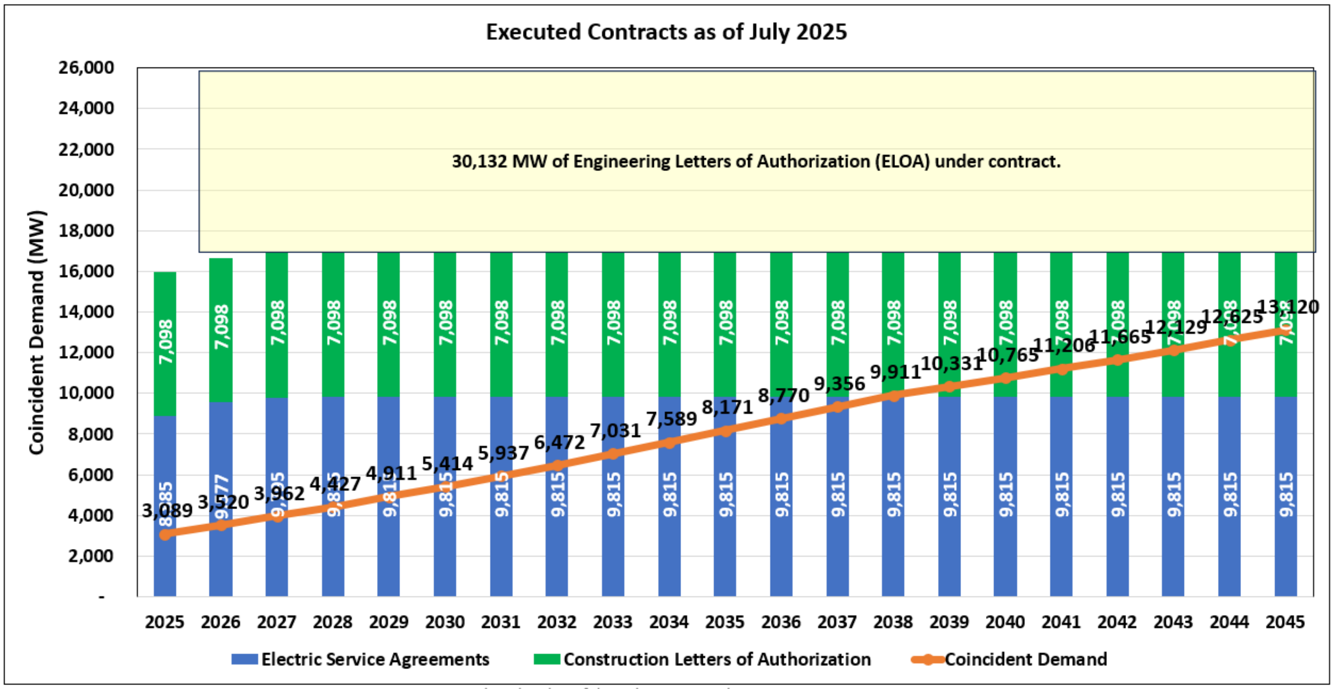

Figure 2.1.15 illustrates the significant growth in contracts from 2023 to 2025, as well as the movement of projects through the three stages of contracts. As of July 31, 2025, the Company has 16,913 MW of requested capacity under firm contracts through executed ESAs or CLOAs. The Company is currently studying an additional 30,132 MW of data center capacity at the ELOA stage.

[11] While the Company does not forecast data center load by contract, the Data Center Load Forecast is validated by the significant number of executed contracts with customers. The Company uses a three-contract structure with large load customers that bind customers to increasing financial commitments as projects progress.

Figure 2.1.15: Data Center Contract Growth

	Contract Values		
Capacity (MW)	**End of July 2023**	**End of July 2024**	**End of July 2025**
ESAs	5,827	8,012	9,815
CLOAs	2,008	5,835	7,098
Firm Capacity	**7,835**	**13,847**	**16,913**
ELOAs	8,658	7,570	30,132
Total Contracts	**16,493**	**21,417**	**47,045**

Data center customer load is unique. Data centers operate with a very high load factor, meaning the consumption of energy is very high relative to the level of demand. Said differently, data centers have a constant 24x7x365 energy profile. In addition to building infrastructure to serve these customers, the Company offers a number of DSM programs that data centers have and are able to take advantage of, including a program tailored to data center measures, as well as new construction, automation, lighting, HVAC, and other energy efficiency products. Dominion Energy continues to explore opportunities for and interest in demand response programs with its largest customers. To date, data centers have been hesitant to participate in demand response or interruptible service participation programs; the Company has seen no evidence that data center customers are willing to reduce load in response to high price signals. As PJM recently stated in its pre-filed comments for the FERC technical conference, the lack of participation indicates to PJM that the risk of interruptions, especially for customer-facing processes, far exceeds any economic value of participation under current incentive structures and market conditions.[12]

2.2 Updates to the PJM Market Affect the Planning Environment

Dominion Energy participates in the PJM capacity planning process and capacity auctions to ensure supply of sufficient capacity resources to meet its customer load. As a member of PJM, the Company has two options to meet its capacity requirements: (1) participation in the reliability pricing model ("RPM") forward capacity market, like any other capacity supplier, or (2) utilization of the fixed resource requirement ("FRR") alternative.

Dominion Energy currently participates in RPM capacity market. The RPM is PJM's resource adequacy construct, and its purpose is to develop a long-term pricing signal for capacity resources within each Load Deliverability Area ("LDA") obligations. The PJM LDA for the Company is the equivalent of the DOM Zone. Under the RPM, utilities participate in PJM auctions to meet capacity obligations through a clearing mechanism that uses a pre-defined demand curve and clears offered generation supply resources against that demand curve.

[12] Federal Energy Regulatory Commission AD25-7-000, PJM Capacity Market Forum, Pre-filed Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C. at 11 (May 20, 2025).

2.2.1 Capacity Planning

As a member of PJM, Dominion Energy is a signatory to PJM's Reliability Assurance Agreement ("RAA"), which obligates the Company to purchase sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone using its annual load forecast and reserve margin[13] guidelines as inputs. PJM then conducts a capacity auction process for meeting these input requirements up to three years into the future. This auction process includes the Base Residual Auction ("BRA") for the RPM as well as subsequent incremental auctions that are held to allow market sellers and PJM to adjust positions for changes such as load forecasts, generator retirements, Effective Load Carrying Capability ("ELCC"), construction delays, or outage assumptions. This auction process determines the clearing reserve margin and the capacity price for each zone for the delivery year that is three years in the future.

The Company is required to provide sufficient generation to cover its load obligation, which is calculated using PJM's most current load forecast and planning parameters such as equivalent forced outage rate demand ("EFORd"),[14] ELCC, and reserve margin requirements.

Dominion Energy uses PJM's reserve margin guidelines to determine its long-term capacity requirement. PJM conducts an annual reserve requirement study to determine an adequate level of capacity in its footprint to meet the target level of reliability, measured as a loss of load expectation equivalent to one day of outage in ten years.

PJM develops reserve margin estimates for planning (*i.e.*, delivery) years (June through May) rather than calendar years. Because PJM is a summer peaking entity, and because the summer period of PJM's planning year coincides with the calendar year summer period, calendar and planning year reserve requirement estimates are determined based on the identical summer period. For example, the Company uses PJM's 2026/2027 delivery year assumptions for the 2026 calendar year in this 2025 IRP Update because it represents the expected peak load during the summer of 2026.

The Company makes one assumption when applying the PJM reserve margin to its modeling efforts. Since PJM uses a shorter capacity planning period than the Company (*i.e.*, ten years for PJM rather than 20 years for this 2025 IRP Update), the Company uses the most recent PJM Reserve Requirements Study and assumes the reserve margin value for Delivery Year 2034 would continue to the end of the Planning Period (*i.e.*, 2045).

Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions, revisions to the PJM RPM rules, and annual updates to load and reserve requirements.

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[13] A reserve margin is the total amount of capacity to meet customers' peak loads reliably to account for plant outages and other uncertainties.

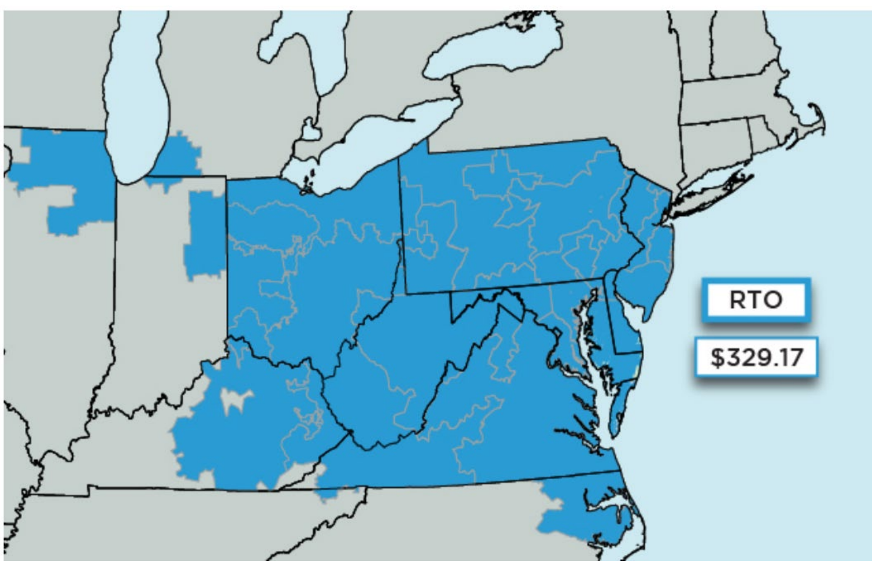
[14] EFORd is a measure of the probability that the generating unit will not be available due to a forced outage or forced derating when there is a demand on the unit to generate.

Appendix 2B-8 provides a summary of PJM's summer and winter peak load and energy forecast, while Appendix 2B-9 provides a summary of projected PJM reserve margins for summer peak demand.

2.2.2 The 2026/2027 PJM BRA Results

On July 22, 2025, PJM published the results of the BRA for the 2026/2027 Delivery Year (see Figure 2.2.2.1). The results showed that the entire PJM footprint cleared at the FERC-approved cap of $329.17/MW-day.[15] This is nearly 22% higher increase from the 2025/2026 BRA results for PJM. The DOM Zone did not separate from the rest of PJM in the 2026/2027 auction, with the zonal price easing modestly from the elevated $444.26/MW-day for 2025/2026. However, the underlying pressures that drove DOM Zone's separation in 2025/2026 remain, including load growth, supply tightness, and limits on transmission import capability. More importantly, the PJM RTO remains concerningly close to falling short of procuring the capacity needed to maintain reliability. For resources offered under the RPM construct, PJM procured 134,205 MW of unforced capacity ("UCAP") for 2026/2027. Excluding resources offered under the Fixed Resource Requirement alternative, PJM calculated an RTO reliability requirement of 134,414 MW of UCAP. In other words, PJM already finds itself on the verge of falling short of its capacity targets. With the DOM Zone a net importer of energy, this further underscores the need for additional capacity within the Company's footprint.

Figure 2.2.2.1: PJM 2026/2027 RPM Capacity Auction Results - Capacity Prices[16]



[15] See footnote 1.

[16] https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250722-pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal.pdf.

Elevated capacity prices reflect the urgency of resource adequacy concerns not just for DOM Zone but across PJM, affirming that robust investment in new dispatchable generation resources and new transmission infrastructure is critical to reliably serve the growing needs of our customers in Virginia and North Carolina.

2.2.3 Resource Adequacy and Market Functioning Challenges in PJM Capacity Market

Va. Code § 56-599 requires every IRP to consider energy independence along with rate stability, economic development, and service reliability. PJM is responsible for finding the least cost means of satisfying demand while meeting reliability requirements, and dispatches power generators within the entire RTO accordingly. Dominion Energy works with PJM to satisfy its requirements through load procurement in the PJM market. The Company also coordinates with PJM on power generation in the operational space through day-ahead offering of its generating units into the market and real-time dispatch of the units.

Even though PJM dispatches generators within its entire footprint to meet its load requirements, Dominion Energy is responsible for responding to its customers' demand growth. The Company must adjust to load shape changes in its service territory (*i.e.*, shifts in the timing of demand highs and lows), which requires appropriate dispatch and resource mix adjustments. Dominion Energy meets demand for electric service with a combination of its dispatchable units, renewable and energy storage resources, and market purchases.

The Company has depended upon market power purchases for an increasing share of total energy served, purchasing between 20 to 22% of total energy in 2021-2024. While market purchases have historically been a part of meeting customers' needs, the Company looks to be less reliant on generation outside of the DOM Zone, as an overdependence on market purchases is a growing cause for concern for several reasons.

The entire PJM region is experiencing unprecedented load growth, which results in challenges in securing capacity resources needed to meet that growing demand. This challenge is exacerbated by (i) significant loss of dispatchable generation capacity throughout PJM due to premature retirements, and (ii) new generation in the PJM interconnection queue being dominated by intermittent resources.[17] A series of PJM reports[18] analyzed the impacts of integration of renewable resources and concluded maintaining reliability as dispatchable generators retire becomes more challenging. In that regard, reserves are declining, which means that generating capacity available to PJM for dispatch exceeds projected demand by a smaller margin than it used to, reducing the

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[17] PJM Interconnection L.L.C., 190 FERC ¶ 61,084 at P 15 (2025) (PJM's study revealed: "(1) the possibility of up to 40 GW of existing generation retirements by 2030; (2) that its new services queue consists primarily of renewable resources and gas-fired resources (representing 94% and 6%, respectively, of the capacity in the queue); and (3) that renewable resources have an historical rate of completion of approximately five percent.") (footnote omitted).

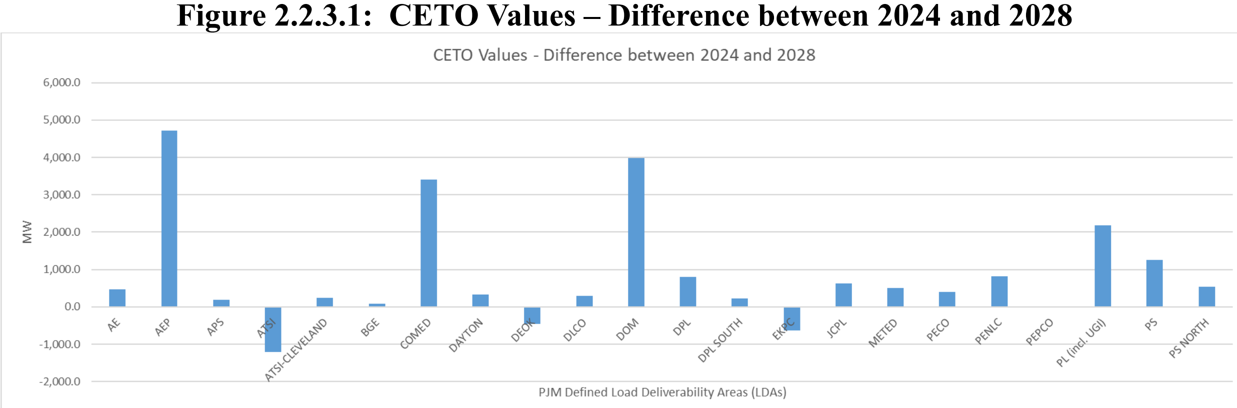
[18] *See* PJM Interconnection, L.L.C., *Energy Transition in PJM: Frameworks for Analysis* (Dec. 15, 2021), and the *Addendum* (Mar. 3, 2022); PJM Interconnection, L.L.C., *Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid* (Oct. 28, 2022), and the *Addendum* (Nov. 10, 2022); PJM Interconnection, L.L.C., *Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Feb. 24, 2023), and the *FAQ* (Apr. 21, 2023); and PJM Interconnection, L.L.C., *Energy Transition in PJM: Flexibility for the Future* (June 24, 2024), and the *Addendum* (Aug. 8, 2024). All of these reports are available at https://www.pjm.com/library/reports-notices.aspx.

safety cushion that is essential for reliability. As a result, power may not be available when it is needed, particularly during extreme weather events or other demand spikes.

Capacity Emergency Transfer Objective ("CETO") of LDAs through PJM are another indicator of the reliability concerns highlighted above. PJM defines CETO as the amount of power that an LDA is expected to require in imports at a time of emergency.[19] At a very high level, the CETO value decreases when there is more supply (*i.e.*, generation) within the LDA and increases when there is more demand (*i.e.*, load). Said another way, the CETO is an indication of the supply/demand balance within an area, with an increase being indicative that demand is increasing and there will be less power available to other LDAs in the event of extreme hot or cold conditions.

Figure 2.2.3.1 provides the change in CETO from 2024-2028 across PJM's LDAs as aggregated through the BRA Planning Parameters.[20] The increase in the CETOs is another signal that utilities should be cautious regarding market reliance in planning to meet customers' needs. Particularly of note is that the Company's neighbor, American Electric Power ("AEP"), went from being able to export power during an emergency to requiring imported power for an emergency. This indicates that in an emergency where the Company needs to import power, AEP will likely also need to import power during the same weather event.

Figure 2.2.3.1: CETO Values – Difference between 2024 and 2028



While the Company will still look to the PJM markets to provide energy and capacity as needed to meet the Company's load requirements in the immediate term, resource adequacy is a vital issue that must be addressed at the state level, along with a closer examination of the purpose and intent of the BRA.

The BRA—Base *Residual* Auction—was designed as a market to procure *residual* capacity. In that regard, PJM envisioned that LDAs would secure their capacity by building resources themselves or procuring them with bilateral contracts and use the BRA to manage relatively modest long or

[19] See Section C.2 of PJM Manual 14B - pjm.com/-/media/DotCom/documents/manuals/m14b.pdf

[20] The parameters were taken from the 2024/2025, 2025/2026, 2027/2028 auctions which can be downloaded from https://www.pjm.com/markets-and-operations/rpm.

short positions.[21] Over time, however, LDAs have increasingly used the BRA as the primary place to obtain needed capacity. When load growth increased exponentially as dispatchable generation continued to retire, the utilization of the BRA as a place to procure needed capacity resulted in a dramatic increase in capacity prices. This, in turn, signals the need for new generation to be built. Compounding the issue, though, is the fact that the BRA is not designed to support the needed power generation development. Because the BRA only establishes prices for capacity to be delivered three years in the future and dispatchable capacity resources, like natural gas-fired or nuclear resources, cannot be built in a short three-year timeframe, the BRA does not provide a market result that is capable of matching supply and demand for all the types of needed capacity or the long-term revenue certainty needed to incentivize development of capital-intensive capacity resources.

Capacity availability and reliability (*i.e.*, generator class ELCC ratings based on performance in extreme load events) also affect prices. Had there been more generating capacity available within the DOM Zone for the 2026/2027 capacity auction, capacity prices within DOM Zone could have cleared at a lower price. However, due to generation capacity scarcity, the entire PJM RTO cleared at the cost cap, as discussed in Chapter 2.2.2.

Improvements in the transmission system can alleviate constraints and lead to better power flows for import into the DOM Zone. Additionally, these improvements lead to lower price volatility while minimizing uneconomic generation dispatch. Ultimately, transmission expansion contributes to a more resilient grid through higher efficiency in generation dispatch and power flows, resulting in lower power generation costs for customers. However, the extent to which transmission enhancements could be helpful depends on availability of dispatchable generation within both PJM and the Eastern Interconnection.

Dominion Energy is taking prudent actions in the hourly energy market, as well as short-term and long-term planning spaces to ensure available supply of energy. This includes energy trading, entering into bilateral contracts (*i.e.,* PPAs), generation dispatch planning and ensuring fuel supply, transmission and distribution enhancements (*e.g.*, Grid Enhancing Technologies ("GETs")) and expansion, implementing energy efficiency and DSM programs to reduce customer load, building energy storage facilities, and developing new technologies.

Even though the Company is actively pursuing all available options for ensuring reliable supply of energy, it is operating in the dynamic regulatory and market environment in which action or inaction of other market participants, for example through retirement of generating units against the backdrop of growing demand for power, impact power availability and pricing.

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[21] The RAA "is intended to ensure that adequate Capacity Resources, including planned and Existing Generation Capacity Resources, planned and existing Demand Resources, and Energy Efficiency Resources will be planned and made available to provide reliable service to loads within the PJM Region, to assist other Parties during Emergencies and to coordinate planning of such resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace. To accomplish these objectives, this Agreement is among all of the Load Serving Entities within the PJM Region." PJM Interconnection L.L.C., Intra-PJM Tariffs, RAA, Article 2 – Purpose.

Load growth is expected to continue. To avoid overreliance on the energy and capacity markets and protect customers from resource scarcity and market volatility, the Company is developing and building generating capacity, as discussed in Chapters 3.2, 3.5, and 3.5.2. Dominion Energy's on-demand and renewable generation resources complement one another to power our customers reliably and affordably. Each class of energy generators serves a specific need but is not sufficient in isolation. The diversity and reliability of our power generation fleet provides the flexibility necessary to safely and effectively respond to various operational and weather conditions.

2.3 Transmission Considerations

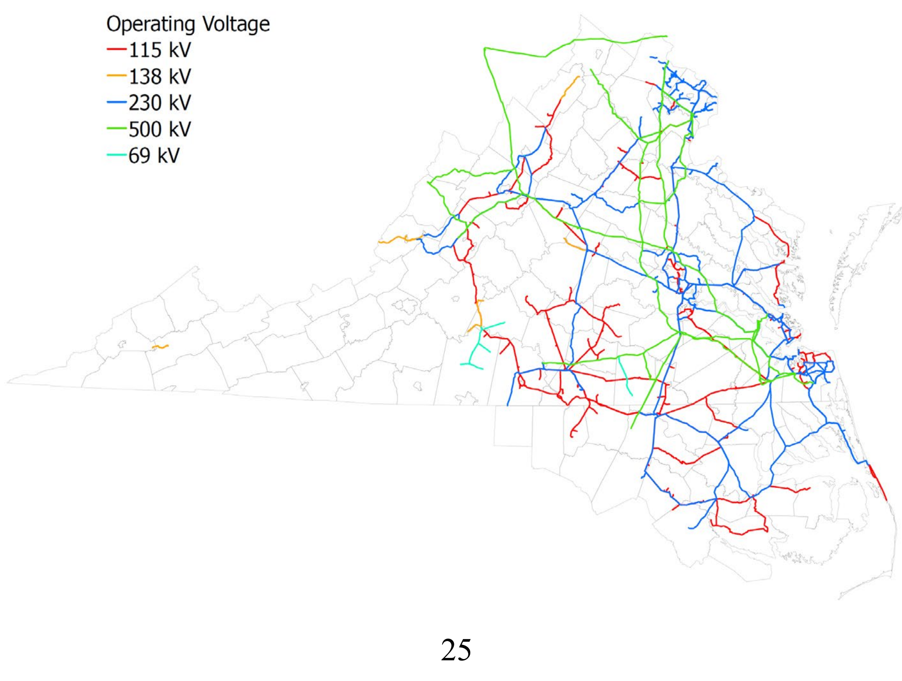
2.3.1 Transmission Planning

Dominion Energy owns the transmission system for the DOM Zone. In addition to the cooperatives dependent on the Company's transmission system, several independent power producers are interconnected with and are dependent on the Company's transmission system for delivery of their capacity and energy into the PJM market. Appendix 2D includes additional detail regarding the relationship between the Company and PJM specific to the operation and planning of the transmission system.

2.3.2 Existing and Future Transmission Facilities

Dominion Energy has approximately 6,800 miles of transmission lines in Virginia, North Carolina, and West Virginia at voltages ranging from 69 kV to 500 kV, with these facilities integrated into PJM. Figure 2.3.2.1 below shows the Company's existing transmission lines.

Figure 2.3.2.1: Dominion Energy's Existing Transmission Lines ≥ 69kV



A list of the Company's transmission lines and associated facilities that are under construction or planned during the PJM RTEP Planning Period can be found in Appendix 2C, including projected cost per project as submitted to PJM as part of the RTEP process.

Since the 2024 IRP, PJM selected several electric transmission projects through its Open Window process that will be jointly developed by Dominion Energy, AEP, and FirstEnergy Corp. The approved projects, which are in the early stages of development and will require permitting and regulatory approval, include several new 765, 500, and 345 kV transmission lines in Virginia, Ohio, and West Virginia. Additionally, Dominion Energy was awarded nearly 100 electric transmission projects totaling $1.5 billion as part of PJM's 2024 RTEP Open Window #1.

Further, during the PJM 2025 RTEP Open Window #1, which ended in August 2025, the Company proposed multiple new electric transmission projects up to 765 kV, including a high-voltage direct-current ("HVDC") line that, if selected by PJM, will be the first HVDC installation in the Company's territory. PJM will provide information on the preliminary approvals of the selected projects in early 2026.

During their evaluation for the 2025 Market Efficiency Open Window ("ME Open Window"), PJM found one congestion driver in the DOM Zone to address, which was the result of a buildup of renewables in the area. The Company proposed seven possible solutions, including three line upgrade proposals, two substation expansions, and two Battery Energy Storage System ("BESS") solutions. The Company anticipates PJM to choose solutions in early 2026.

The Company also continues to work with PJM to find cost-effective ways to upgrade existing infrastructure on existing rights-of-way (*i.e.*, uprates). This approach has led to a significant number of 230 kV line uprates that are in various stages of engineering and construction.

Additionally, the Company continues to evaluate and deploy GETs to improve transmission system capacity and flexibility. Software GETs optimize system topology to enhance power flow and reduce congestion while hardware GETs solutions upgrade physical assets and infrastructure such as advanced conductors, Flexible AC Transmission devices, dynamic line ratings, and automatic power flow controllers. More details on current and future plans for GETs on the transmission network are detailed in Appendix 2D.

2.3.3 Transmission System Reliability Analyses

The Company continues to conduct reliability analyses to study the impacts of increased demand, increased penetration of renewable energy and energy storage resources, and retirement of synchronous generators on the transmission system and address any necessary upgrades that may be needed to ensure reliability. The Company has included and will continue to include up-to-date reliability analyses in its IRPs and update filings.

The Company performed the following analyses for this 2025 IRP Update: (1) an import limit study for the DOM Zone; (2) an inertial and frequency response study to evaluate the increasing penetration of inverter-based resources; (3) a short circuit analysis to evaluate the system's ability to quickly recover from faults; and (4) a review of system restoration and black start capabilities. Details on the methodologies used for these analyses and their results are provided in Appendix 2D. The analyses continue to show that traditional synchronous generation is needed to help maintain system reliability.

2.4 Distribution Considerations

As society has grown more dependent on electricity, customers are increasingly intolerant of power outages. Fundamental changes in the energy industry driven by the rise in distributed energy resources ("DERs") and expanding electrification, however, have prompted the need for utilities across the country to modernize their distribution grids and transform how distribution grid planning occurs. The Company continuously identifies new scenarios and solutions to ensure safe and reliable service, including emerging technologies, such as a comprehensive DERs management system, customer-owned assets leveraged for grid support as non-wires alternatives, and grid hardening to support a more resilient distribution system.

The Company's distribution planning process is largely consistent with the 2024 IRP (see Appendix 3L of the 2024 IRP). The Company continues to invest in distribution grid initiatives, including the Grid Transformation Plan, the Strategic Undergrounding Program ("SUP"), the Battery Storage Pilot Program, the Electric School Bus Program, and the Rural Broadband Program. See Appendices 3M and 3N of the 2024 IRP for additional details on the projects and successes of the Grid Transformation Plan and the Company's current integrated distribution planning ("IDP") roadmap, respectively. See also the Company's most recent Grid Transformation Plan Phase IIIB filing approved in Case No. PUR-2025-00051.

Additionally, there have been significant policy developments at both the federal and state levels over the past several years that support the need for distribution grid transformation. At the federal level, for example, the FERC issued a final rule, known as FERC Order 2222, in 2020 (with updates in 2021) that allows for aggregation of all manner of DERs for participation in regional markets, like PJM, with the goal being to better enable DERs to participate in those markets. To accomplish this goal, FERC Order 2222 defines DERs broadly to include "any resource located on the distribution system," which can include "storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment," and allows bundling or aggregating the output of several DERs to facilitate DER participation in regional markets. This aggregating feature is significant, as it allows aggregated DERs to participate in their wholesale regional markets on a comparable level with other resources.

In light of fundamental policy developments, like FERC Order 2222, the Company, PJM, and others have begun significant work to implement the order and modernize the distribution grid in preparation for integrating DERs. Specific to the Company, to respond to the modernization need, the Company developed a 10-year plan to transform its grid to meet the changing landscape of the energy industry while continuing to provide reliable service to customers. The Company's Grid

Transformation Plan sets out a two-phased approach, with Phase II primarily focusing on facilitating the integration of DERs, given the proliferation of DERs and the market opportunities created by FERC Order 2222, in conjunction with continuing to address reliability and security associated with DERs.

On the state level, on May 2, 2025, the Commonwealth of Virginia enacted Va. Code § 56-585.1:16 (HB 2346/SB 1100), which is a Company-specific DER policy development. It requires the Company to petition the Commission for approval of a pilot program that will focus on evaluating methods to optimize demand through various technology applications, including establishing virtual power plants ("VPP"). The statute defines VPP to mean "an aggregation of distribution energy resources, enrolled either directly with an electric utility or indirectly through an aggregator, that are operated in coordination to provide one or more grid services," and it requires the pilot to include aggregations of DERs totaling up to 450 megawatts and located in multiple geographic regions. The purpose of the pilot program is to allow the Commission to review data and results to evaluate the program's effectiveness in providing grid services during times of peak demand, as well as consider "lessons learned" in relation to implementation of FERC Order 2222 by PJM and the "complementary role of virtual power plants in the retail electricity market in the Commonwealth." Currently, the Company is preparing an application to be filed in accordance with the statute's mandate to petition the Commission for approval of a pilot program that complies with the statutory requirements by December 1, 2025.

GETs are a wide classification that can encompass almost any advancement deployed on the grid. The Company views many of its initiatives, including its Grid Transformation Plan filings as grid enhancing technologies at the distribution level. Examples of GETs at the distribution level include fault location, isolation and restoration ("FLISR"), voltage optimization, advanced metering infrastructure ("AMI"), and substation technology deployment. Moreover, the Company is continuously evaluating new technologies and piloting certain technologies where appropriate, such as battery energy storage systems, that potentially serve as non-wires alternatives for the distribution system. While the Company has also evaluated advanced conductors for distribution application, it determined that they are a transmission-specific grid enhancing technology.

Embedded in all of the Company's initiatives is a focus on cyber and physical risks. Accordingly, the Company continues to assess and evaluate new technologies as they emerge, and going forward, will continue to evaluate the application of GETs and advanced conductors, particularly regarding their role in ensuring grid reliability and safeguarding cybersecurity and physical security of the electric distribution grid, in future IRP filings.

2.5 Generation Considerations

2.5.1 Expanding Generation Resource Adequacy

Historically, the Company's transmission planning considers the entire DOM Zone, whereas the Company's generation planning focuses primarily on the DOM LSE. The tightening supply of energy and capacity and increasing demand, however, suggest that the Company is beginning to compete more often with other LSEs for available energy in the PJM market, especially during peak demand hours and/or severe weather events. As a result, the Company is more closely considering the energy and capacity needs of the entire DOM Zone when planning for generation as it is far and away the largest power generator in DOM Zone and all LSEs within the DOM Zone face the same constraints on their ability to rely on market purchases to maintain reliability and affordability.

To assess the amount of hourly energy potentially available for purchase from PJM to serve DOM LSE customers for planning purposes, the Company started with the transmission import limit for DOM Zone and scaled it down to the DOM LSE level, similar to how the Company scaled down the PJM DOM Zone Load Forecast to the DOM LSE level. The impact of the import limit on the Portfolios addressed in this 2025 IRP Update is discussed in Chapter 5.1.

2.5.2 Development Challenges

The siting, development, and construction of new power generation resources – across all technologies – continue to face mounting challenges, including interconnection delays, strained supply chains, labor shortages, land use conflicts, permitting hurdles, and trade barriers. While PJM interconnection reform is progressing, the transition is still underway and presents significant challenges, particularly due to the extended timelines for interconnection studies and the high costs associated with network upgrades and interconnection facilities. Supply chain challenges stem from rising demand, material shortages, escalating prices, shipping delays, and regulatory or trade barriers that affect both the availability and cost of materials and components. For example, there are supply shortages, price increases, and shipping delays associated with key materials to construct new solar facilities, such as polysilicon, solar glass, and semiconductor chips.

For energy storage projects, materials such as lithium, cobalt, and nickel, are in short supply. In addition, growing demand for skilled labor in the manufacturing and installation of power generation systems, combined with broader labor shortages, continues to slow project deployment and increase labor costs. Permitting delays and evolving land use requirements also contribute to extended construction timelines and increased project costs.

The July 4, 2025, enactment of the federal H.R. 1 (the “Tax Bill”), is also expected to have implications on planned and future renewable projects, as it significantly modifies the Inflation Reduction Act’s long-term tax credit framework by rendering wind and solar projects placed in service after December 31, 2027, ineligible for these credits; though, the legislation includes some safe harbor provisions for near term projects.

Tariffs and Foreign Entity of Concern (“FEOC”) requirements are also changing the development and construction of new power generation projects, particularly in solar and energy storage technologies. These measures restrict access to critical materials and components—such as solar panels, inverters, and battery minerals—sourced from certain foreign suppliers, increasing costs and limiting availability. As developers navigate these trade and compliance barriers, project timelines are extended and procurement strategies must be restructured, adding uncertainty and complexity to an already strained supply chain environment.

Lastly, local zoning and land use decision making in Virginia has emerged as a challenge to the development of new power generation projects, particularly utility-scale solar and energy storage. While the state has set ambitious clean energy goals, some localities have adopted restrictive zoning ordinances or imposed de facto moratoriums that limit or prohibit new projects. As a result, proposed projects face prolonged approval timelines, increased costs, and a heightened risk of project denial.

Chapter 3. Producing Cleaner Energy While Ensuring Reliability

Dominion Energy relies on a diverse resource mix, including its own generating resources, PPAs, and market purchases, to meet customers' energy and capacity needs and ensure system reliability. While the demand for power has been growing, carbon emissions from the Company's generating fleet have fallen significantly since the year 2000. The Company has implemented more than 40 DSM programs, which offset the need for energy and capacity. To meet the development targets of the VCEA, the Company seeks proposals to acquire renewable and energy storage projects and enter into PPAs for the output from such projects. While the Company is developing and building renewable resources, natural gas-fired electric generating units are facilitating the transition to clean energy by reliably generating power when customers need it the most. As demand increases, gas-fired resources bridge the gap, allowing time for new generation technologies, such as nuclear small modular reactors, or long-duration energy storage, to continue being researched, developed, piloted, and ultimately deployed. At the same time, Dominion Energy plans to proactively position itself in the short-term (*i.e.*, 2026 to 2030) to meet its commitment to provide reliable, affordable, and increasingly clean energy for the benefit of all customers over the long term.

3.1 Supply-Side Generating Resources

3.1.1 System Resources

The Company operates a diverse fleet of generation resources in North Carolina, Virginia, and West Virginia. Figure 3.1.1.1 shows the Company's 2024 capacity resource mix by unit type.

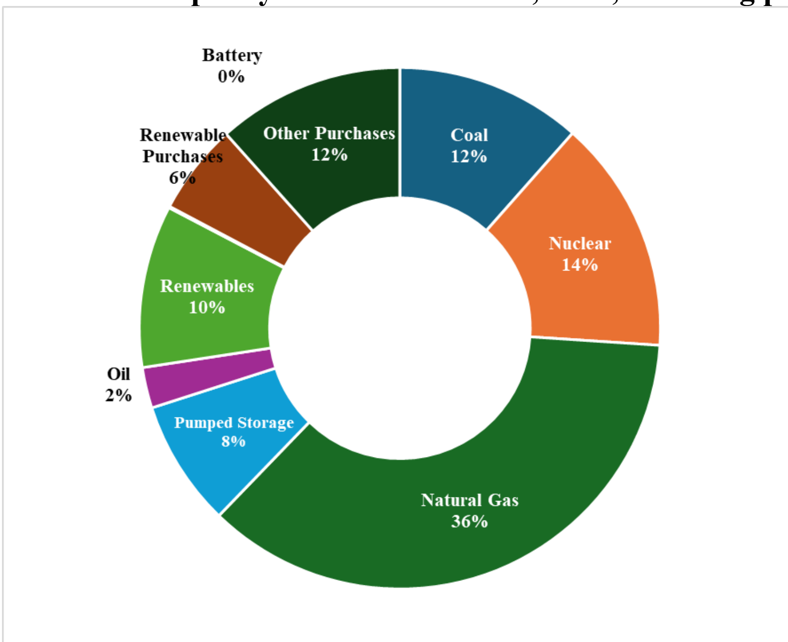
Figure 3.1.1.1: 2024 Capacity Resource Mix by Unit Type

Figure 3.1.1.1	**2024 Capacity Resource Mix by Unit Type**	
Generation Resource Type	**Net Summer Capacity (MW)**	**Percentage of Net Summer Capacity**
Coal	2,663	11.5%
Nuclear	3,348	14.5%
Natural Gas	8,350	36.2%
Pumped Storage	1,808	7.8%
Oil	583	2.5%
Renewable - solar, wind, hydro, biomass	2,324	10.1%
Battery Energy Storage	20	0.1%
Renewable Purchases	1,302	5.6%
Other Purchases	2,681	11.6%
Total	**23,079**	**100.0%**

Note: Some of the Company's natural gas units have dual-fuel capability. Oil units run only on oil.

Figures 3.1.1.2 and 3.1.1.3 provide the Company's 2024 actual capacity and energy mix, which are not equivalent due to differences in operating and fuel costs of various types of units and PJM system conditions. Appendix 3A provides capacity-related information directed by the SCC.[22]

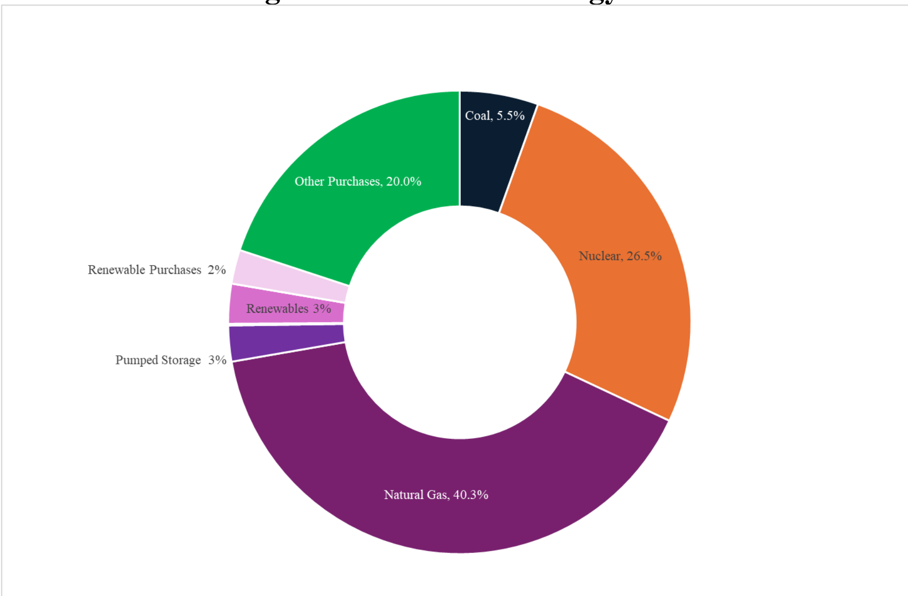
Figure 3.1.1.2: Capacity Mix
(Summer Installed Capacity as of December 31, 2024, including purchases)



This represents *potentially available contribution* of each type of generating resource owned by the Company or procured through bilateral transactions (such as bundled PPAs) as well as capacity from ring-fenced units.

[22] There have been no new notifications to PJM of the Company's intention to retire or deactivate Company-owned units since the Company's 2023 IRP. Accordingly, there is no information to provide in response to (vi) of the SCC's directive in Case No. PUR-2020-00035 (Final Order at 11 n. 50).

Figure 3.1.1.3: 2024 Energy Mix



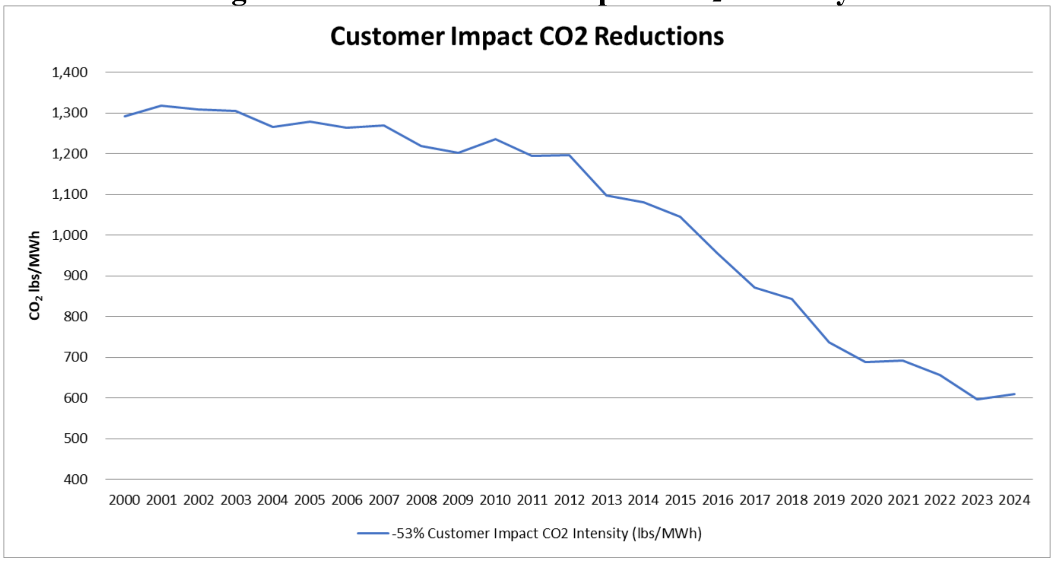
The energy mix chart shows the *sources of energy actually delivered* to the Company's customers in 2024. Although still relatively small, energy supplied by solar in 2024 increased over 10% from 2023.

Dominion Energy supplements its generation fleet with third-party PPAs. The Company has contracts with renewable energy PPAs, for approximately 1,506 MW (nameplate capacity) online and operating as of the end of 2024.

3.1.2 Company-Owned System Generation – Reduction in Emissions

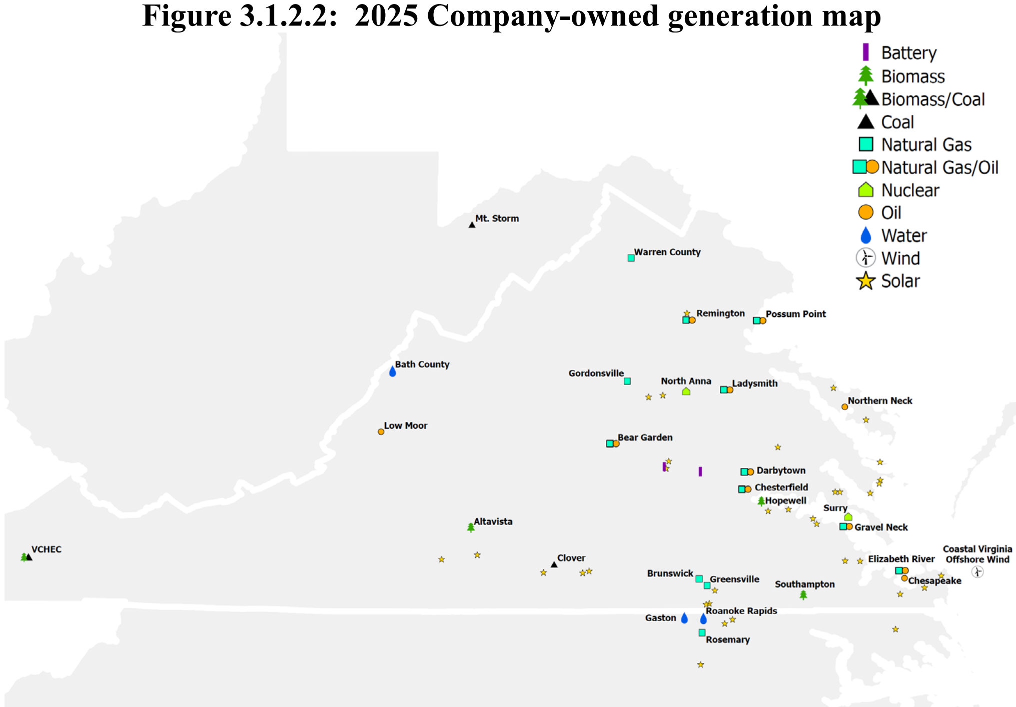
Over the past two decades, the Company has made changes to its generation mix that have significantly improved environmental performance. These changes include the retirement of certain units, the conversion of certain units to cleaner fuels, and the addition of air pollution controls. This integrated strategy has resulted in significant reductions in carbon dioxide ("CO_2") emission intensity. CO_2 intensity is the quantity of emissions per megawatt hour ("MWh") delivered to customers. This calculation includes emissions from any source used to deliver power to customers, including Company-owned generation, PPAs, and net purchased power. As shown in Figure 3.1.2.1, customer impact CO_2 intensity has decreased by 53% since 2000.

Figure 3.1.2.1: Customer Impact CO_2 Intensity



A diverse set of power generation technologies, including renewable power technologies, energy storage, and dispatchable technologies such as natural gas and nuclear, is crucial for maintaining grid reliability. Figure 3.1.2.2 provides an overview of the Company's current generation fleet and locations. The sections below discuss future generation resources that are planned or under development. Appendix 3C provides additional details.

Figure 3.1.2.2: 2025 Company-owned generation map



Renewable energy resources not only provide a carbon-free energy alternative to power but also contribute several additional grid reliability benefits, including diversification, resilience to extreme weather, and support of energy storage solutions. Energy storage plays a vital role in enhancing grid reliability by balancing supply and demand, providing backup power, reducing peak demand costs, and supporting renewable energy integration. The sections below discuss future generation resources that are planned or under development. Appendix 3C provides additional details

3.2 Building Renewable Energy Resources

To support the development of renewable and energy storage resources, the Company annually issues requests for proposal ("RFPs") for new solar (utility-scale and distributed), energy storage, and onshore wind resources, seeking proposals for projects for the Company to acquire and bundled PPAs for the Company to purchase the output from new projects. The 2024 IRP (Chapter 3.2) has a full description of renewable and energy storage resources. Below is information that has been updated since the 2024 IRP.

3.2.1 Solar Facilities

Since the passage of the VCEA, Dominion Energy has petitioned for the SCC approval of 4,849 MW of Company-owned solar projects and solar PPAs in its annual Renewable Portfolio Standard ("RPS") Development Plan proceeding.[23] Most of these projects and PPAs have received SCC approval and are in the development, construction, or operation phase.

In North Carolina, the Company has entered into PPAs totaling nearly 700 MW (nameplate) with qualifying facilities under the Public Utilities Regulatory Policies Act.

3.2.2 Energy Storage

To date, the SCC has approved the Company's development of 28.34 MW of the 30-megawatt pilot allowance in the Grid Transformation Security Act of 2018. Additional information about the Company's long duration storage pilot is provided in Chapter 3.7 of the 2024 IRP. Additionally, Dominion Energy has petitioned for SCC approval of approximately 700 MW of energy storage in its annual RPS Development Plan proceeding.[24]

Dominion Energy is also partnering with the Virginia Department of Emergency Management and All Hazards Consortium on a pilot program in support of the Federal Emergency Management Agency's Building Resilient Infrastructure and Communities initiative to utilize mobile energy storage systems during emergencies for back-up power to critical locations.

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[23] The total amount of MW includes the solar projects that are being petitioned for concurrently with the filing of the 2025 IRP Update in the Company's 2025 RPS Development Plan proceeding, Case No. PUR-2025-00148.

[24] Includes energy storage projects that are being petitioned for concurrently in the Company's 2025 RPS Development Plan proceeding.

In addition to these pilot projects, the Company continues to self-develop energy storage resources and solicits energy storage PPAs in annual RFPs.

3.2.3 Energy Efficiency and Demand Response as Resources to Manage Customer Load

Dominion Energy is committed to helping customers find ways to save energy and money, which is why the Company offers over 40 energy savings programs.

Residential customers can earn rebates for conserving energy at peak times by participating in the Company's demand response programs, save energy with smart technology and ENERGY STAR® Products, earn rewards for managing EV charging, and benefit from a home energy audit, including a virtual energy audit by implementing energy efficiency upgrades throughout the home. The Company's most vulnerable customers have additional participation opportunities through an income- and age-qualifying bundle and weatherization programs, which provide no cost home energy assessments, improvements to eligible customers' home heating and cooling systems, and other energy efficiency upgrades free of charge to income and age qualifying customers.

Non-residential customers can invest in upgrades that save energy, engage in a customized energy savings program for their distinct business needs, and maximize savings with building controls. These DSM programs both benefit participating customers and reduce the overall energy and demand requirements on the system. Energy savings from the Company's DSM programs are forecasted to save and reduce energy requirements by 1,462 gigawatt hours ("GWh") in 2025 and 3,011 GWh by 2030. From a demand perspective, DSM programs also reduce the summer capacity needs by 341 MW in 2025 and 1,076 MW by 2030. See Appendix 3D for additional information. Additional information about the Company's active programs and recently approved programs is provided in Appendices 3E and 3F, respectively.

3.3 Resource Adequacy

Resource adequacy is the ability of the electric system to supply the aggregate energy requirements of electricity to consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. Today, diverse resource fleets across the Eastern Interconnection generally allow for power exchanges between PJM and its neighboring RTOs, although extreme weather can challenge the stability of the Eastern Interconnection absent significant new investments.

To meet the growing demand, the Company makes infrastructure investments in its generation, transmission, and distribution systems. The Company and PJM continue to study the impacts of increasing penetration of renewable generation on reliability of the bulk electric system. Renewable energy resources are not a one-for-one replacement for traditional dispatchable generation resources. Generally, more installed capacity of solar and energy storage resources is necessary to equate the capacity and energy that traditional generation provides. A flexible and diverse portfolio that includes dispatchable, renewable, and energy storage resources, as well as enhanced coordination across the Eastern Interconnection will be needed to maintain system balancing and ramping needs and to ensure system reliability.

3.3.1 Near-term Supply Outlook in PJM

There is currently approximately 234 GW (nameplate) of new planned generation in PJM's active interconnection queue, with about 90% of those projects requesting an in-service date by 2027. Of this 234 GW, 97% is comprised of non-dispatchable solar and wind, as well as storage resources, with 6.6 GW of new natural gas making up the remaining approximately 3%. Historically, only a portion of queued projects in PJM have developed. Recently, queue processing backlogs have further exacerbated completion timelines and completion rates. Estimates are that 38 GW of new generation could be online in PJM by 2030, the majority of which consists of renewable and energy storage resources with approximately 2 GW of new natural gas.

State decarbonization policies incentivize and/or mandate the retirement of traditional dispatchable generation both in the Company's service territory and in the wider PJM region. Existing and recent environmental regulations that impact the dispatch and continued operation of existing resources and the construction of new resources are summarized in Appendix 5A. See also Appendix 5A Environmental Regulations Table 1 from the 2024 IRP.

Given the environmental regulations and anticipated retirements of fossil units, available generation will decrease, even as demand continues to grow. Over 16 GW of coal and gas generation in PJM have announced their intention to retire, but this amount could double if all retirements incentivized and/or mandated by state and federal policies materialize. Overall, these trends show renewable generation facilities would replace retiring fossil generation. Because of this change in the inherent composition of the supply mix, the impact of this transition on an accredited capacity basis (*i.e.*, UCAP basis) will be disproportionate. The anticipated addition of 36 GW of renewable and energy storage resources will largely have lower marginal ELCCs than retiring conventional resources, translating to only about 6 GW of UCAP additions.

3.3.2 Reserve Requirements

Reserve requirements ensure that enough resources are available to reliably operate the system when unusual conditions occur. Balancing Authorities, such as PJM, establish reserve requirements based on NERC Reliability Standards. Both operating and planning reserves are required to maintain system reliability. Different types of resources provide different types of reserves. For instance, traditional dispatchable and energy storage resources can provide operating reserves, but renewable resources generally cannot. Therefore, a diverse mix of generation resources is needed to ensure reserve requirements are met.

3.4 Nuclear

For over half a century, nuclear energy has delivered reliable, affordable, and carbon-free electricity to meet customer load demand, and it continues to play a fundamental role in decarbonization. As the need for reliable, increasingly clean power grows, nuclear energy remains essential to maintaining both reliability and affordability. Dominion Energy has extended the life of its existing nuclear units and is evaluating opportunities to expand its nuclear portfolio with the addition of small modular reactors ("SMRs"), which offer enhanced flexibility and scalability. While traditional large-scale nuclear facilities remain a potential option, their development depends on identifying suitable sites that meet requirements for land, water resources, and emergency planning zones, as well as practicable economics.

3.4.1 Small Modular Reactors

As discussed in the 2024 IRP, the Company continues to believe SMRs will be an important part of future generation profiles. SMRs represent a significant advancement in nuclear energy technology, with the SMR landscape continuing to rapidly diversify. Drawing on decades of operational experience with conventional light water reactors, SMRs offer a modernized nuclear solution that enhances safety, increases deployment flexibility, and aligns with evolving energy system requirements.

With outputs typically around 300 MW per unit, SMRs are roughly one-third to one-fifth the size of conventional reactors, which makes SMRs well-suited for a range of locations, including existing nuclear power stations, brownfield sites, and industrial areas closer to demand centers. Importantly, SMRs are designed to operate around the clock, with some designs classified as dispatchable resources, able to ramp up or down to meet demand, much like natural gas-fired plants. This flexibility makes them an asset for grid reliability and for integrating more renewable energy sources.

While SMRs have not yet been deployed at scale, significant progress is being made. The U.S. Nuclear Regulatory Commission has approved NuScale Power's design, issued a final safety evaluation for Kairos Power's demonstration reactor, and accepted TerraPower's and X-Energy's construction permit applications.

Since the 2024 IRP, in November of 2024, the Company filed its first Rider SMR to recover costs associated with early-stage development of one or more SMRs at the North Anna Power Station. In July of 2025, the Virginia SCC approved the filing.

Dominion Energy is actively advancing its continued evaluation of SMR technologies and potential deployment. Following the July 2024 Request for Proposals, the Company continues to analyze the feasibility of siting one or more SMRs at the North Anna Power Station. The Company also continues to explore opportunities for innovative financial partnerships with third parties and high load customers, which may provide avenues for earlier deployment of SMRs than reflected in the Portfolios discussed in Chapter 5 of this 2025 IRP Update.

3.4.2 Traditional Scale Reactors

Traditional, or large-scale, nuclear power plants, like the Company's Surry and North Anna nuclear stations, remain a proven source of reliable, carbon-free baseload electricity. As such, they play a critical role in supporting grid stability and decarbonization. Deploying new traditional facilities, especially on greenfield sites, however, requires careful evaluation given the substantial land needed for infrastructure and protective buffers, as well as significant water resources necessary for cooling. These needs can limit siting options, particularly in areas with environmental or logistical constraints. Further, the standard 10-mile Emergency Planning Zone, or EPZ, for traditional reactors may restrict deployment, making greenfield siting even more complex.

While the deployment of two units at Plant Vogtle demonstrates feasibility, that project also highlighted challenges with extended construction timelines and complexity of building non-modular, large-scale infrastructure. Traditional nuclear remains a viable option, but its deployment must be weighed against a myriad of potential constraints—land, water, regulatory, and financial. Modular technologies, like SMRs, thus may offer more flexible and scalable alternatives for future energy needs.

3.5 Reliability Resources Under Development

3.5.1 Natural Gas-Fired Units

Natural gas resources are essential for reliability and work in tandem with renewable resources. With flexible operating characteristics, giving them the ability to follow load, natural gas units support the grid by generating energy when it is needed. The units are able to turn on, run during the times of peak energy usage, and/or when intermittent resources are not available, and then turn off. This mitigates the risk of insufficient generation during the swings in energy output of intermittent generation.

For example, Winter Storm Enzo hit the Company's service territory from January 21-23, 2025, bringing record-breaking low temperatures and snowfall across the southeast. The DOM Zone set an all-time peak load on January 21, then broke that all-time peak on January 22 with a record 23,573 MW, and then broke it again the morning of January 23 with 24,678 MW. The DOM LSE's share of these January 22 and 23 record peaks was 18,552 MW and 19,379 MW, respectively. Due to the early morning winter hours, solar generation was insignificant, accounting for less than 1% of demand, and this event further showed the need for every generating unit in the Company's fleet to be dispatched to meet the system peak early in the morning when renewable resources were not producing energy. This type of extreme weather event threatens reliability and requires resources to ensure the Company can meet customer demands. PJM has specifically identified critical concerns associated with maintaining reliability during the transition to a system built on clean energy resources. The Company is evaluating sites and equipment for the construction of new gas-fired units.

Utilities are developing advanced class Combustion Turbines ("CTs") in a simple-cycle capacity to reduce emissions while maintaining the flexibility to meet peak loads. The Company included advanced class Combined Cycle ("CC") units in a 2x1 configuration, which represents two advanced class CTs and a steam turbine. With the addition of the steam turbine that utilizes steam from the gas turbines' exhaust heat, these units are more efficient, thus reducing emissions per megawatt-hour generated. These units are not peaking facilities but would operate more often to serve customers' day to day loads.

To meet the energy and capacity needs associated with the load forecast and without a commercially viable carbon-free, dispatchable generation alternative, natural gas generation will be a critical component to ensuring the ability to reliably meet generation demand. The Company continues to work toward executing contracts to help secure fuel supply for its gas facilities.

3.5.2 Future Supply-Side Resource Options

The following section provides updated details on certain newer supply-side resource options the Company has considered and will continue to evaluate for possible inclusion in future IRPs. For more information on newer supply-side resource options that the Company has considered, see Chapter 3.7 of the 2024 IRP.

- **Long Duration Energy Storage ("LDES"):** LDES technologies offer extended discharge durations compared to conventional lithium-ion batteries. These systems fall into three primary categories based on their design: thermal, electrochemical, and mechanical.

  Across the U.S., companies are in various stages of planning and piloting projects to validate emerging technologies, explore use cases, and build momentum for broader commercialization. Dominion Energy recently received approval from the SCC to pilot three non-lithium-ion technologies—two of which qualify as LDES. At Darbytown Power Station, two electrochemical systems will be tested, a Zinc-Halide battery with a 4-hour discharge duration and an Iron-Air battery capable of discharging for up to 100 hours. At Virginia State University, a Nickel Hydrogen batter with a 10-hour discharge duration will be piloted.

  Beyond these pilots, the Company continues to evaluate the LDES market and engage with technology developers pursuing commercialization. However, most LDES technologies currently face technical challenges including roundtrip efficiency, durability and degradation, capital and O&M costs, and safety and operational limitations. Additionally, LDES developers face commercialization hurdles including value proposition (cost, performance metrics, and value of integration into the electric grid), resource maturity, scalability, as well as hurdles to large-scale deployment like permitting, environmental, and safety requirements.

Current LDES pilots aim to generate initial performance and cost data to validate use cases and support future investment and customer deployment decisions. However, further development is needed to bring LDES technologies to the maturity level of lithium-ion batteries and pumped hydro storage. The testing of non-lithium products provides useful data points, that can be incorporated into future versions of the technology, making them more useful to support grid-based operations.

The Company is also evaluating additional LDES technologies such as:

- **Advanced Compressed Air Energy Storage**: Stores energy by compressing air and capturing heat during compression for reuse during discharge, eliminating the need for fossil fuels.
- **Liquid Air Energy Storage**: Cools air to cryogenic temperatures for storage as a liquid, then expands it to drive turbines and generate electricity.
- **Flow Batteries**: Use liquid electrolytes stored in external tanks, allowing energy capacity to scale independently from power output.
- **Thermal Energy Storage**: Stores energy by heating or cooling a medium. Approaches include sensible heat (*e.g.*, molten salts), latent heat (*e.g.*, cryogenic), and thermochemical heat (*e.g.*, chemical looping).

As these technologies are deployed and field data becomes available, Dominion Energy will expand the number of LDES resources considered in future IRPs.

3.6 The Five-Year Reliability Plan

Over the next five years (*i.e.*, 2026-2030), Dominion Energy plans to proactively position itself to meet its commitment to provide reliable, affordable, and increasingly clean energy for the benefit of all customers over the long term. See Chapter 3.8 of the 2024 IRP for a full description of the Five-Year Reliability Plan. The sections below provide some highlights and/or updates to the 2024 IRP.

3.6.1 Generation Reliability and Resource Adequacy

Dominion Energy plans to take the following actions related to existing and proposed generation resources:

- Execute on a responsible replacement strategy for recent retirements of coal-fired and oil-fired generators to the extent necessary to maintain reliability:

- Continue the development of gas-fired generation, including but not limited to, brownfield sites to take advantage of existing CIRs.
  - Continue evaluating opportunities for uprates or increased CIRs at existing generating units, as presented in Appendix 3B-11.
  - Advance the development of SMRs, as discussed in Chapter 3.4.1.

- Maintain existing generating units to maximize their performance and ensure regulatory compliance:

  - Continue necessary operation and maintenance and capital expenses in each unit.
  - Continue to petition for regulatory approvals of investments necessary to comply with environmental rules, including those described in Chapter 5.1.

- Maintain and enhance fuel security for existing units:

  - The Company has received a Certificate of Public Convenience and Necessity Amendment and has begun construction on a liquefied natural gas ("LNG") Storage Facility (Case No. PUR-2024-00096), which will provide backup fuel to the Company's critically important Greensville and Brunswick Power Stations.

- Pilot energy storage projects, as discussed in Chapters 3.2.2 and 3.5.2.

- Continue to execute on the VCEA mandates and continue to meet targets under North Carolina's renewable energy portfolio standard at a reasonable cost and in a prudent manner, and submit its annual compliance report and compliance plan to the NCUC.

3.6.2 Demand-Side Management

Dominion Energy will continue to identify and propose new, revised, or bundled cost-effective DSM programs that work towards Commission-approved energy savings targets and beyond in conjunction with the established DSM stakeholder process and recommendations from the Company's long-term DSM plan.

In Virginia, Dominion Energy filed its Phase XIII DSM application in December 2024, seeking approval of five new programs as a continuation of prior programs nearing completion, one new program, and one pilot, as well as enhancements to existing programs. The SCC issued its final order approving the programs and enhancements but denying the pilot program on August 13, 2025.

In North Carolina, Dominion Energy will continue its analysis of future programs and will file for approval with the NCUC for those programs that continue to meet Company requirements for new DSM resources and have been approved in Virginia, while also meeting the expectations of the NCUC regarding cost-effectiveness and applicability.

3.6.3 Transmission

Dominion Energy plans to take the following actions related to existing and proposed transmission resources:

- Continue to assess the Company's transmission system needs to upgrade or construct facilities required to meet the needs of its customers. Work with PJM to find cost-effective ways to upgrade existing infrastructure and invest in new infrastructure to support demand growth, as discussed in Chapter 2.3.2.
- Pursue necessary regulatory approvals of new transmission lines needed to rebuild aging infrastructure, interconnect data center customers, address reliability criteria violations, and interconnect new renewable energy projects and reliability projects approved through the PJM Open Window process.
- Continue to study the transmission system reliability needs resulting from the addition of significant renewable energy resources and the potential retirement of synchronous generator facilities, as discussed in Chapter 2.3.3.

3.6.4 Distribution

Distributed renewable, inverter-based resources significantly contribute to the need for investment in electric distribution equipment and technologies to ensure power quality. Over the next five years, Dominion Energy plans to take the following actions:

- Continue implementing the Virginia Grid Transformation Plan ("GTP"), including initiatives to facilitate the integration of DERs, enhance distribution grid reliability, resiliency, and security, and improve customer experience.
- Continue making targeted investments in base program reliability improvement.
- Explore the use of energy storage systems as a non-wires alternatives pilot through the GTP to find more affordable and streamlined solutions for interconnection.
- Continue developing IDP capabilities, including advancing load and DER forecasting capabilities.
- Continue the SUP.
- File for regulatory approval for deployment of a VPP of up to 450 MW, as discussed in Chapter 2.4.

Chapter 4. Commitment to Affordability

Dominion Energy provides electric service at affordable and competitive rates to residential, commercial, and industrial customers. Our electric rates continue to compare favorably to inflation and national average electric rates on both a current and historical basis. Based on its latest projections of electric rates in the forward-looking bill analysis, the Company expects to maintain its long record of very competitive rates.

4.1 Residential and Commercial Energy Rates Comparison

Dominion Energy is committed to providing affordable, reliable, and increasingly clean electric service to its customers. Affordable electric rates are key to customers' well-being and satisfaction, as well as to encourage economic development and growth across Virginia and North Carolina.

The Company evaluates success in providing affordable service based on how its electric rates compare to national and regional averages, as well as the stability of its rates over time and in comparison to the general rate of inflation. Electric rates—typically expressed as cents per kilowatt-hour of usage—are used as the point of comparison instead of total electric bills because electric bills alone are not reflective of how much customers are spending on energy overall. For instance, many Virginians and North Carolinians use electricity for both summer cooling and winter heating, while customers in other states with colder climates such as in the Northeast and Mid-West rely to a greater extent on natural gas, propane, or fuel oil for winter heating. That service is billed separately and therefore is not accounted for if one just compares electric bills. The comparison of electric rates presents a clear picture of the per-unit cost of electric service, irrespective of customers' propensity to use electricity over any other fuel, how much square footage they are heating or cooling, the age of the housing stock relative to other jurisdictions, etc.

The stability of the Company's electric rates can be expressed as a CAGR. Between July 2008 and July 2025, the rate paid by a typical residential customer of Dominion Energy increased by about a 1.99% CAGR, while the rate paid by a typical large industrial customer increased on a compound annual basis by about 1.25%. Over the same time period, the Consumer Price Index for All Urban Consumers, a proxy for inflation, increased by a CAGR of 2.29%

Affordability can also be viewed through the lens of comparisons over time and the overall stability of electric rates. Accordingly, the Company charts its history of delivering competitively priced electric service, relative to the national average, for both residential and large industrial customers in Figures 4.1.1 and 4.1.2, respectively, below.

Figure 4.1.1: Historical Dominion Energy Residential Rate vs. U.S. Energy Information Administration ("EIA") National Average

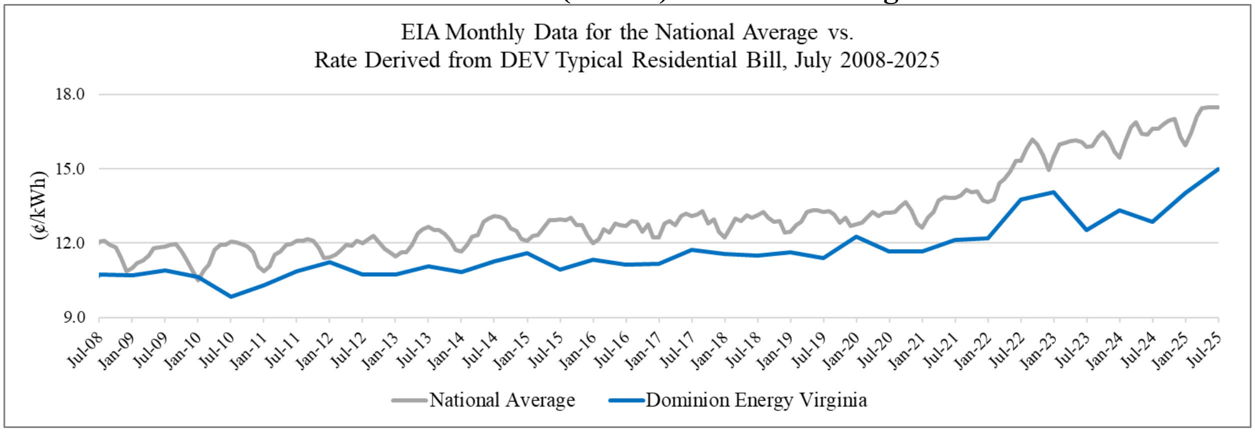
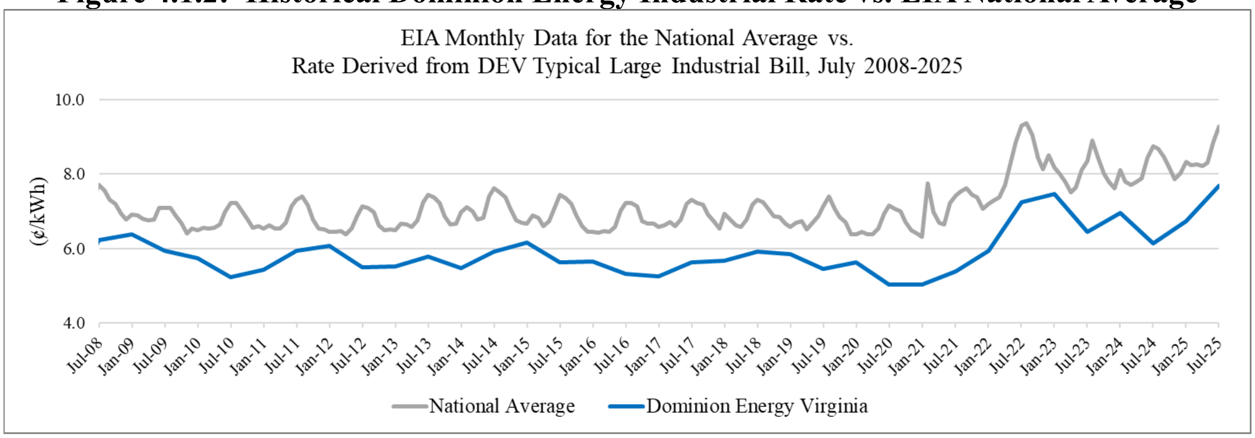


Figure 4.1.2: Historical Dominion Energy Industrial Rate vs. EIA National Average



The Company acknowledges that perceptions of affordability are subjective. They will differ based on customers' individual circumstances and are influenced by factors such as the rate of inflation and other expenses that draw on household and business income. Even so, Dominion Energy's electric rates continue to compare favorably to appropriate benchmarks on both a current and historical, long-term basis. The Company is proud and intends to continue its history of delivering safe, reliable, and increasingly clean electric service at affordable and competitive rates.

4.2. Bill Analysis

4.2.1 Virginia

The Company completed a consolidated bill analysis for each of the three Primary Portfolios presented in the 2025 IRP Update. The analysis encompasses three different customer classes and spans 2019 through 2045.

The Company calculated projected bills for each customer class under each Primary Portfolio using two methodologies: (1) based on requirements set by the SCC ("Directed Methodology");

and (2) using a forecasted system and class sales growth and the associated class allocation factors ("Company Methodology"). Additional detail about these methodologies is provided in Appendix 4A. In respect to the residential bill analysis for this 2025 IRP Update, in order to capture modifications to base rates, the Company forecasted changes to capacity and included a 2% inflationary factor, which was applied to distribution bill components.

Figure 4.2.1.1 shows a comparison of a typical bill for a residential customer using 1,000 kWh, projected utilizing the Company Methodology and the Directed Methodology. As shown in this Figure, at the conclusion of this Planning period, the Company expects to maintain its long record of very competitive rates as shown by the projected bill and CAGR.

Figure 4.2.1.1: Virginia Residential Bill Projections (1,000 kWh per month)

	Company Methodology (includes load growth)				**Directed Methodology** (includes load growth)			
	Projected Bill	CAGR Dec. 2019	CAGR May 2020	CAGR Oct. 2025	Projected Bill	CAGR Dec. 2019	CAGR May 2020	CAGR Oct. 2025
12/31/2019	$122.66				$122.66			
5/1/2020	$116.18				$116.18			
10/1/2025	$159.57				$159.57			
Year End 2035	$255.79	4.70%	5.17%	4.71%	$308.77	5.94%	6.44%	6.65%
Year End 2045	$268.65	3.06%	3.32%	2.61%	$381.61	4.46%	4.74%	4.40%
Total Bill Increase (2045)		$145.99	$152.47	$109.08		$258.95	$265.43	$222.04

4.2.2 North Carolina

The 2024 IRP discussed the new implementation of a North Carolina specific bill analysis based on the final NCUC Order for the 2023 IRP. Additional detail regarding the NC bill analysis is provided in Appendix 4B. Figure 4.2.2.1 shows the results of the bill impact analysis for North Carolina for this 2025 IRP Update.

Figure 4.2.2.1: North Carolina Residential Bill Projections (1,000 kWh per month)

Residential	**Company Preferred Plan**	
	Projected Bill	CAGR
Year End 2024	$ 127.73	
Year End 2035	$ 208.54	4.6%
Year End 2045	$ 172.22	1.4%
Total Bill Increase	$ 44.49	

Chapter 5. Expansion Plan Modeling Assumptions and Results

The 2024 IRP reflected dynamic shifts in Dominion Energy's planning environment which included increasing load, higher and more frequent peaks in customer demand, significant changes to the PJM capacity market, and a new suite of environmental regulations impacting existing and proposed fossil generation. These issues continue to impact the Company's planning assumptions in this 2025 IRP Update along with new developments including the possible repeal of the above-mentioned environmental regulations and the recently signed federal tax bill which removed tax credits for certain renewable resources.

In this 2025 IRP Update, the Company presents three Primary Portfolios to meet customers' needs in the future under different planning assumptions. The Primary Portfolios include two Least Cost VCEA Compliant Portfolios, one of which is the Company Preferred Plan that models the 2024 suite of environmental regulations ("2024 EPA regulations") and one that assumes those regulations are repealed. The third Primary Portfolio retires all carbon emitting resources in the Commonwealth by 2045. In addition, the Company again models a NCUC Directed Portfolio as a Secondary Portfolio, along with multiple sensitivity analyses.

5.1 Modeling Overview

The resource portfolios presented in this 2025 IRP Update are based on updated load forecasts, commodity price forecasts, and generation cost assumptions. With PJM moving to a 20-year planning horizon for its load forecast, the Company is now also using a 20-year Planning Period in its portfolios and sensitivities. In addition, the commodity price forecast utilized as a basis for all portfolios and sensitivities, reflects the provisions of the recently signed Federal Tax Bill,[25] removing tax credits for certain renewable resources. Sensitivities of the base commodity price forecasts are used for the Least Cost VCEA without EPA and the Forced Retirements by 2045 Portfolios, as well as for the Regional Greenhouse Gas Initiative ("RGGI") Sensitivity.

Figure 5.1.1 below provides an overview of the Primary and Secondary Portfolios as well as the Stakeholder Input Case and the high-level assumptions underlying each one. Figure 5.1.2 provides an overview of the build limits for the technologies used in each Portfolio and the Stakeholder Input Case. Appendix 5B provides additional details on the modeling assumptions used in the Portfolios, and charts showing the capacity (summer and winter), energy, and Renewable Energy Certificate ("REC") positions for each Primary Portfolio are provided in Appendix 5C.

Modeling assumptions regarding compliance with the 2024 EPA Regulations Sections 111(b) and 111(d) as well as Effluent Limitations Guidelines ("ELG") were consistent with those used in the 2024 IRP, but the Company did update its assumptions regarding compliance with the Mercury and Air Toxics Standards ("MATS") rule. Since the 2024 IRP, the Mt. Storm Power Station has received a two-year extension for compliance with the updated MATS rule, under a Presidential

[25] One Big Beautiful Bill Act, Pub. L. No. 119-21, H.R.1, 119th Cong. (2025) (the "Federal Tax Bill" or "Tax Bill").

Proclamation. Therefore, the Company did not include any costs for MATS compliance, choosing instead, for modeling purposes, to put the station in outage from July 1, 2029, until January 1, 2030, at which point, it was modeled as a natural gas fired steam generating unit. It is important to note that the Company has made no final decisions as to how it will comply with any of these three rules and will continue to evaluate its options.

Figure 5.1.1: Summary of Modeling Assumptions

Description	Company Preferred Plan	Least Cost VCEA Compliant without EPA	Forced Retirements by 2045	NCUC Directed	Stakeholder Input
Portfolio Type	Primary	Primary	Primary	Secondary	Stakeholder
Commodity Price Forecast	Base	Base w/out EPA	Base w/ Retirements	Base	RGGI
Forced VCEA Dev Targets (65/35)	Yes	Yes	Yes	No	Yes
Retirements by 2045	Model Selected	Model Selected	Yes	Model Selected	Model Selected
Selectable Incremental Gas Resources	Yes	Yes	Yes	Yes	No
Other Selectable Generation Resources	Yes	Yes	Yes	Yes	Yes
Build Limits	Comply with all Build Limits	Comply with all Build Limits	Expanded Build Limits and Technology	NCUC Directed	Stakeholder Directed
EE (2028)	Targets Set by SCC	Targets Set by SCC	Targets Set by SCC	Targets Set by SCC	Targets Set by SCC
Env. Regs	With EPA	Without EPA	With EPA	With EPA	With EPA
Capacity Imports	20% of LSE Load Decreasing to 10%	20% of LSE Load Decreasing to 10%	20% of LSE Load Decreasing to 10%	20% of LSE Load Decreasing to 10%	5,000 MW

Figure 5.1.2 Summary of Annual and Total Plan Resource Build Limits

Annual Build Limit/Total Plan Limit (MW)	Company Preferred Plan	Least Cost VCEA Compliant without EPA	Forced Retirements by 2045	NCUC Directed	Stakeholder Input
Battery Storage (4hr)	350/NL	350/NL	350/NL	350/NL through 2032 550/NL 2033-2036 700/NL 2037-2040 950/NL 2041-2045	350/NL
Long Duration Storage (10hr)	NA	NA	350/NL	350/NL*	350/NL
Utility Scale Solar	1020/NL	1020/NL	2040/NL	1020/NL through 2032 1220/NL 2033-2037 1500/NL 2038-2045	2040/NL
Distributed Solar	81/NL through 2027 102/NL 2028 -2029 120/NL 2030-2045	81/NL through 2027 102/NL 2028 -2029 120/NL 2030-2045	81/NL through 2027 102/NL 2028 -2029 120/NL 2030-2045	81/NL through 2027 102/NL 2028 -2029 120/NL 2030-2045	81/NL through 2027 102/NL 2028 -2029 120/NL 2030-2045
Solar+Storage Hybrid	NA	NA	NA	100/100	100/100
Generic Onshore Wind	60/60	60/60	60/60	60/60	60/60
Offshore Wind 1	2600/2600	2600/2600	2600/2600	2600/2600	2600/5200
Offshore Wind 2	800/800	800/800	800/800	800/800	800/800
Nuclear-SMR	324/NL	324/NL	648/NL	324/NL	324/NL
Nuclear-Large Scale	2234/2234	2234/2234	2234/4468	2234/2234	2234/2234
2x1 CC	1466/5864	1466/5864	1466/2932	1466/5864	NA
2X Advanced Class CT	882/2646	882/2646	882/1764	882/2646	NA
4X CT Aero	208/416	208/416	NA	208/416	NA

*NCUC Directed Battery Storage (4hr) limit shown applies to the sum of 4hr and 10hr; "NL" – No limit

5.1.1 Primary Portfolios

The Company modeled three Primary Portfolios: the Company Preferred Plan, the Least Cost VCEA Compliant without EPA, and the Forced Retirements by 2045 Portfolios. Primary Portfolios are intended to utilize the Company's base planning assumption of being fully VCEA compliant and then least-cost optimized, and all include a customer bill analysis.

Table 5.1.1.1 shows a high-level overview of the modeling results of these three Primary Portfolios. An overview of key observations associated with the results of the Primary Portfolios also follows. Net Present Value ("NPV") as used in this context represents the 20-year cost of the resources included in a portfolio in 2025 dollars.

Table 5.1.1.1: Primary Portfolios Modeling Results Summary

	Company Preferred Plan	Least Cost VCEA Compliant without EPA	Forced Retirements by 2045
NPV Total ($B)[1]	$148.7	$142.1	$170.6
Construction CAPEX[2] ($B)	$91.8	$80.1	$270.4
Approximate CO_2 Emissions from Company in 2045 (Metric Tons)	39.9 M	49.2 M	7.3 M
Solar (MW)	17,534	17,534	19,754
Wind (MW)	3,460	3,460	3,460
Storage (MW)	2,000	2,000	9,075
Nuclear (MW)	1,944	1,296	12,244
Natural Gas Fired (MW)	8,510	8,510	3,814
Retirements (MW)	-	-	12,705

[1] The NPV Total is calculated based on the time period of 2026 to 2045. It is important to note that since the Forced Retirements by 2045 Portfolio includes generation units (*i.e.*, large-scale nuclear) chosen at the end of the Planning Period, only a couple of years of cost recovery of those units is included in the NPV. This results in a skewed view of the NPV results when comparing to other Portfolios. The Construction CAPEX shows a better representation of the impact of the build plan for the Forced Retirements by 2045 Portfolio.
[2] Represents incremental capital investment for generic resources selected in each Portfolio.

Overview of the Results of the Primary Portfolios

The following are key observations for the Primary Portfolios:

- In the Company Preferred Plan, VCEA resources (*i.e.*, solar, wind, battery storage) will comprise approximately 20% of the Company's capacity mix in 2026 and over 50% by 2045.
- The Forced Retirements by 2045 Portfolio requires approximately $180 billion of additional construction spend compared to the Company's Preferred Plan.
- Due to continuing changes in the PJM Market along with an increasing load forecast, the model remains capacity-limited.

- SMR units continue to provide a steady supply of energy and capacity throughout the Planning Period and are essential for ensuring reliability.
- Large-scale nuclear was made available in all scenarios but was only selected in the Forced Retirements by 2045 Portfolio.
- No retirements of existing generating units were economically selected by the model, accordingly retirements are only included in the Forced Retirements by 2045 Portfolio.
- Natural gas-fired Combined Cycle Units were selected the first year they were made available in all primary Portfolios.
- Even with the addition of 8.5 GW of new natural gas-fired generation, the carbon intensity decreases across all Primary Portfolios.
- The NPVs for the Portfolios that include the 2024 EPA regulations are at least $6.6 billion more costly than the Portfolio that does not.

NPV of the Primary Portfolios

Dominion Energy evaluated the three Primary Portfolios to compare the NPV of utility costs over the Planning Period. Table 5.1.1.2 presents these NPV results on the "Total System Costs" line, as well as the estimated NPV of proposed investments in the Company's transmission and distribution systems, broken down by specific line item.

Table 5.1.1.2: NPV results for the Primary Portfolios

($B)	Company Preferred Plan	Least Cost VCEA Compliant without EPA	Forced Retirements
Total System Costs	$121.9	$115.2	$143.7
Grid Plan (Net of Benefits)	$(2.2)	$(2.2)	$(2.2)
SUP	$0.8	$0.8	$0.8
Transmission	$28.3	$28.3	$28.3
Total Plan NPV	$148.7	$142.1	$170.6

Notes: NPV calculated over the time period of 2026 to 2045. As previously ordered by the SCC, this figure includes incremental cost estimates associated with transmission and distribution investments. All costs are estimates and will vary based on the actual generation, transmission, and distribution infrastructure developed to meet customer needs. (1) Total system costs include the results from Figures 5.1.1.3 through 5.1.1.5 plus approved, proposed, future, and generic DSM, as applicable; costs related to environmental laws and regulations; renewable energy integration costs; and REC banking as discussed in Appendices 2E, 3D, 5A, and 5B. (2) All NPVs are calculated with a 6.62% discount rate. (3) Numbers may not add due to rounding.

Company Preferred Plan

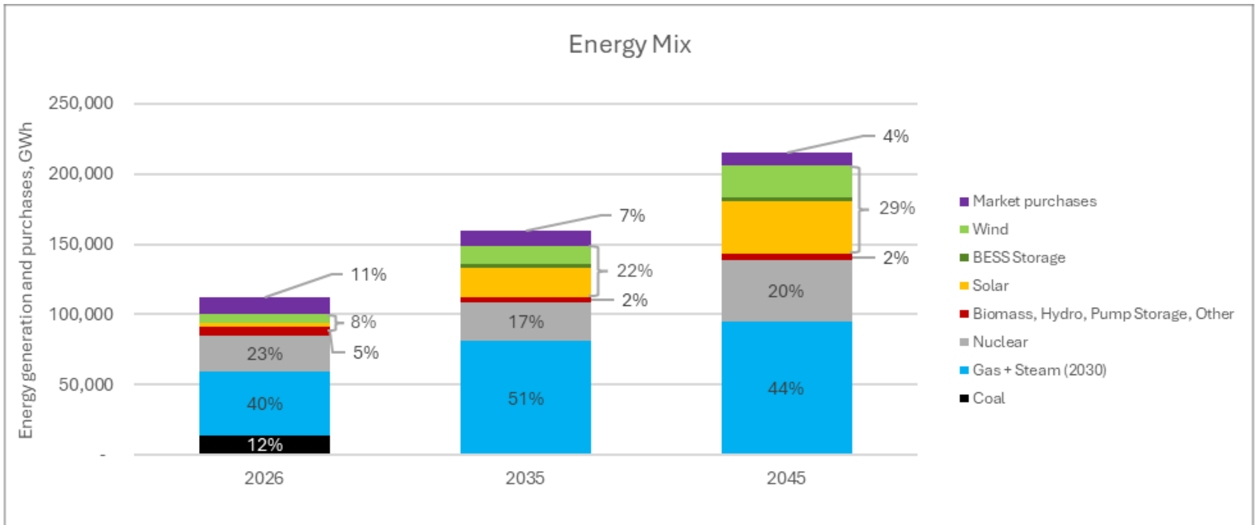
The Company Preferred Plan is a least cost VCEA compliant portfolio that meets all applicable requirements of the VCEA and then selects resources on a least-cost basis. This Portfolio includes the significant development of solar, wind, and energy storage envisioned by the VCEA, petitioned by 2035 and built by 2039. Furthermore, this Portfolio builds additional solar resources in the form of PPAs, beyond what is required by the VCEA, building a total of 17.5 GW of solar and 2 GW of storage resources. This Portfolio also includes the development of six SMRs, 3.4 GW of offshore wind, and 8.5 GW of gas-fired assets to address future capacity, energy, and system reliability needs. This Portfolio would require the Company to petition the Commission for a reliability exception outlined in the VCEA in order to preserve existing and planned fossil generation from retirement in 2045.

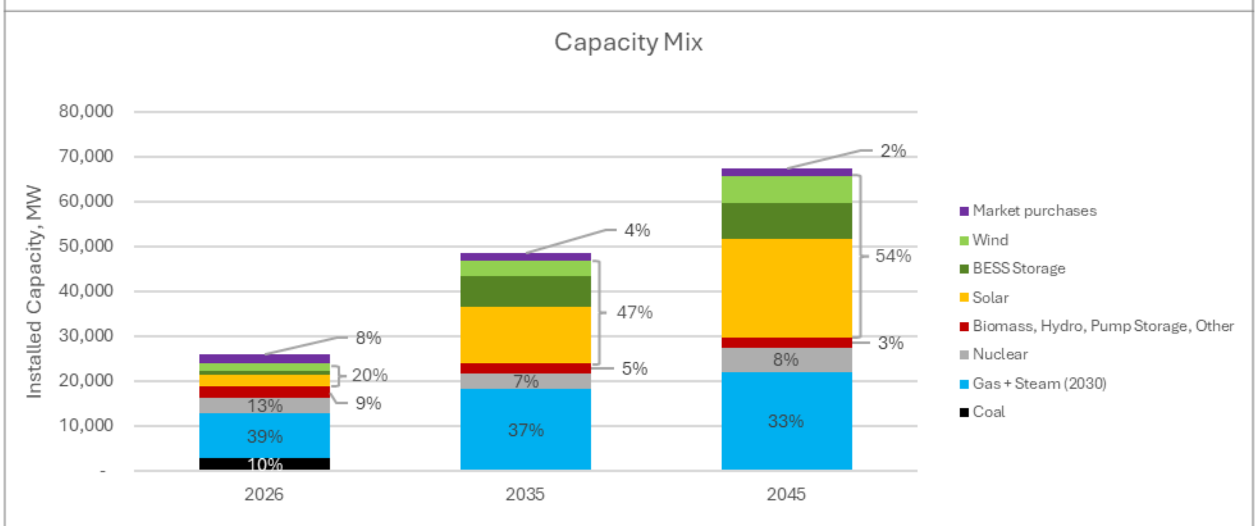
Figure 5.1.1.3: Company Preferred Plan Summary

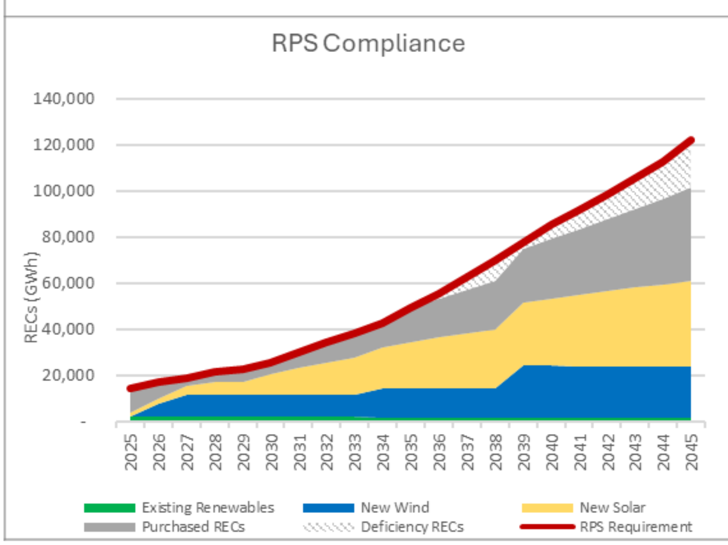
Year	COS Utility Solar	PPA Utility Solar	COS Solar DER	PPA Solar DER	Wind	COS Storage	PPA Storage	Natural Gas-Fired CC	Natural Gas-Fired CT	Nuclear - SMR	Nuclear - Large Scale	Capacity Purchases	Retirements
2026	-	-	-		-	-	-	-	-	-	-	2,100	-
2027	-	-	-		-	-	-	-	-	-	-	2,700	-
2028	-	-	-		-	-	-	-	-	-	-	2,900	-
2029	-	-	-		-	-	-	-	-	-	-	2,800	-
2030	483	555	36	30	-	100	125	-	-	-	-	3,000	-
2031	453	605	45	30	-	100	25	-	-	-	-	3,800	-
2032	453	605	57	30	60	100	25	-	882	-	-	3,700	-
2033	453	605	66	30	-	100	25	1,466	-	-	-	2,900	-
2034	453	605	72	30	800	150	100	1,466	-	-	-	1,800	-
2035	453	605	75	30	-	150	100	-	882	-	-	1,800	-
2036	453	570	79	30	-	150	100	-	882	-	-	1,700	-
2037	453	570	82	30	-	150	100	1,466	-	-	-	1,200	-
2038	453	570	88	30	-	150	100	1,466	-	-	-	700	-
2039	459	570	88	30	2,600	150	-	-	-	-	-	600	-
2040	-	1,020	-	-	-	-	-	-	-	324	-	800	-
2041	-	1,020	-	-	-	-	-	-	-	324	-	1,000	-
2042	-	1,020	-	-	-	-	-	-	-	324	-	1,200	-
2043	-	1,020	-	-	-	-	-	-	-	324	-	1,300	-
2044	-	1,020	-	-	-	-	-	-	-	324	-	1,500	-
2045	-	1,020	-	-	-	-	-	-	-	324	-	1,600	-
Total	**4,566**	**11,980**	**688**	**300**	**3,460**	**1,300**	**700**	**5,864**	**2,646**	**1,944**	**-**	**39,100**	**-**

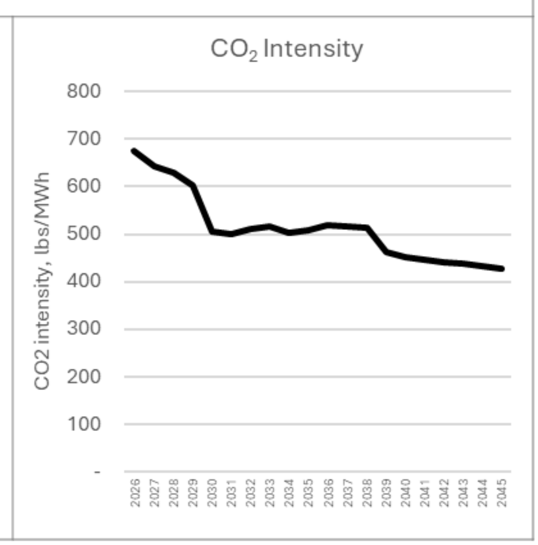
Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units.

Company Preferred Plan Dashboard









Least Cost VCEA Compliant without EPA Portfolio

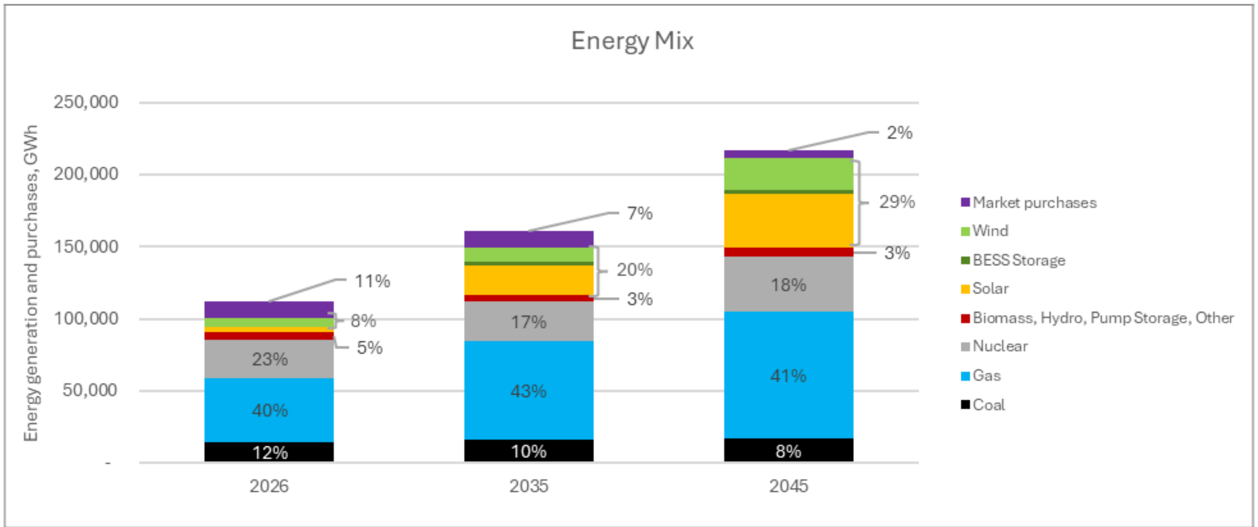
Earlier this year, the EPA began taking steps to repeal many of the 2024 EPA regulations which is further discussed in Appendix 5A. As such, the VCEA without EPA Portfolio utilizes a commodity price forecast that assumes that the 2024 EPA regulations are overturned. In addition, compliance with those regulations was not included in the modeling. With the model being capacity-limited, the resource totals built for this scenario are mostly similar to those for the Company Preferred Plan, building the same amounts of solar, wind, storage, and natural gas resources. In contrast to the Company Preferred Plan, this Portfolio includes the development of four SMRs and includes additional capacity purchases. This Portfolio would require the Company to petition the Commission for a reliability exception outlined in the VCEA in order to preserve existing and planned fossil generation from retirement in 2045.

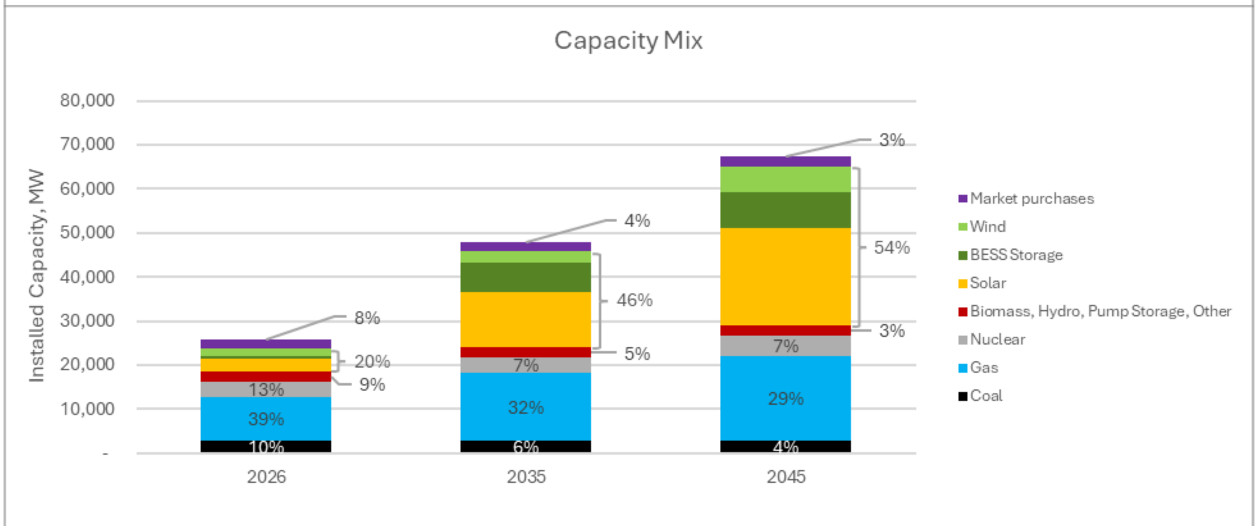
Figure 5.1.1.4: Least Cost VCEA Compliant Without EPA

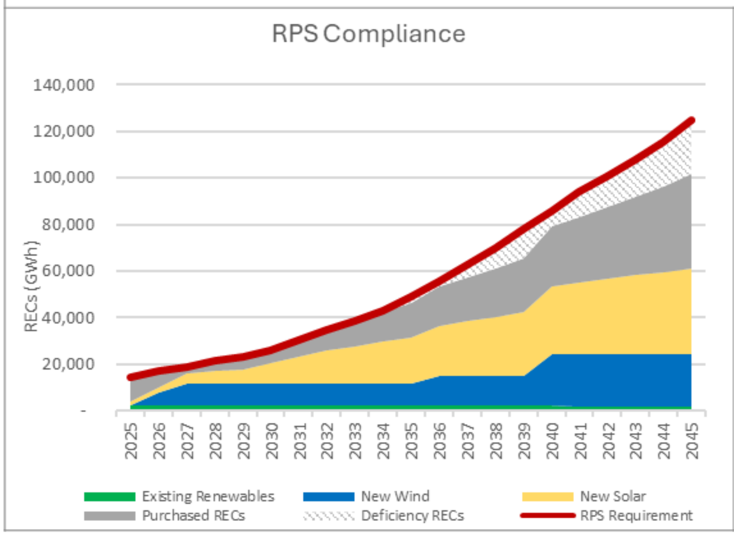
Year	COS Utility Solar	PPA Utility Solar	COS Solar DER	PPA Solar DER	Wind	COS Storage	PPA Storage	Natural Gas-Fired CC	Natural Gas-Fired CT	Nuclear - SMR	Nuclear - Large Scale	Capacity Purchases	Retirements
2026	-	-	-		-	-	-	-	-	-	-	2,100	-
2027	-	-	-		-	-	-	-	-	-	-	2,700	-
2028	-	-	-		-	-	-	-	-	-	-	2,900	-
2029	-	-	-		-	-	-	-	-	-	-	2,800	-
2030	483	555	36	30	-	100	125	-	-	-	-	3,000	-
2031	453	605	45	30	-	100	25	-	-	-	-	3,800	-
2032	453	605	57	30	60	100	25	-	882	-	-	3,700	-
2033	453	605	66	30	-	100	25	1,466	-	-	-	2,900	-
2034	453	605	72	30	-	150	100	1,466	-	-	-	2,000	-
2035	453	605	75	30	-	150	100	-	882	-	-	2,000	-
2036	453	570	79	30	800	150	100	-	882	-	-	1,700	-
2037	453	570	82	30	-	150	100	1,466	-	-	-	1,200	-
2038	453	570	88	30	-	150	100	1,466	-	-	-	700	-
2039	459	570	88	30	-	150	-	-	-	-	-	1,200	-
2040	-	1,020	-	-	2,600	-	-	-	-	-	-	1,100	-
2041	-	1,020	-	-	-	-	-	-	-	-	-	1,600	-
2042	-	1,020	-	-	-	-	-	-	-	324	-	1,700	-
2043	-	1,020	-	-	-	-	-	-	-	324	-	1,900	-
2044	-	1,020	-	-	-	-	-	-	-	324	-	2,000	-
2045	-	1,020	-	-	-	-	-	-	-	324	-	2,200	-
Total	**4,566**	**11,980**	**688**	**300**	**3,460**	**1,300**	**700**	**5,864**	**2,646**	**1,296**	-	**43,200**	-

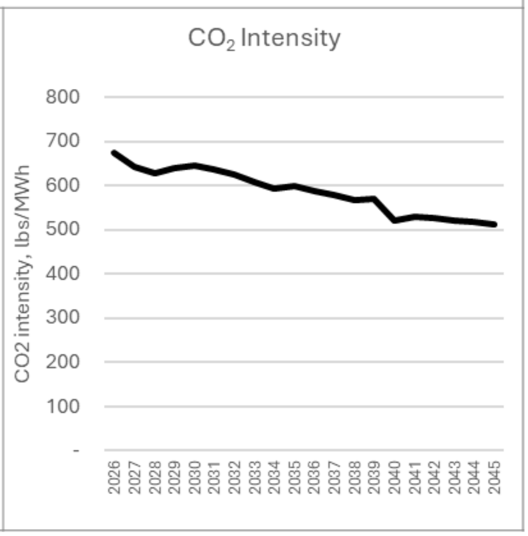
Notes: “COS” = cost of service; “PPA” = power purchase agreement; “DER” = distributed energy resources, whether Company-owned or PPA; “Wind” includes both on and offshore wind units.

Least Cost VCEA Compliant without EPA Dashboard









Forced Retirements by 2045 Portfolio

The Forced Retirements by 2045 Portfolio retires all Company owned carbon-emitting resources in Virginia, with the exception of the Company's biomass units that are not subject to the VCEA, by the end of 2045. The Company does not currently see a viable path towards full retirement of all carbon-emitting resources by 2045; therefore, multiple modeling assumptions were made to derive a case that would fully meet customer requirements. These assumptions included:

- The Company would continue operating the three existing units at its Mount Storm Power Station located in West Virginia as gas-fired boilers beyond 2045 (as this power station is located outside Virginia, it does not fall within the purview of the VCEA);
- Two 2x1 Combined Cycle generation resources are built within the DOM Zone but outside of the Commonwealth of Virginia, each of which do not retire by 2045;
- Appropriate location(s) would be available within the Commonwealth to build four additional large-scale nuclear units;
- Long-duration energy storage technology will be commercially available and deployable at up to 350MW/year by 2036.

In addition, the Company needed to offer the model additional resources in order to meet capacity needs and did so by increasing resource build limits for this Portfolio, beyond those used in the other two Primary Portfolios as follows:

- Doubling the amount of solar to 2,040 MW annually;
- Doubling the amount of SMRs to 2 units annually; and
- Doubling the amount of large-scale nuclear available to the model to 4,468 MW.

Over the 20-year planning period, this Portfolio includes 19.75 GW of solar, 9 GW of storage, 3.4 GW of wind, 7.8 GW of SMRs, and almost 4.5 GW of large-scale nuclear.

As noted in Table 5.1.1.2, the NPV of the Forced Retirements by 2045 Portfolio is approximately $22 billion more costly over the 20-year planning horizon. More notably, however, the construction capital expenditures required under this Portfolio exceed $270 billion (approximately $180 billion more than the Company's Preferred Plan) with much of that cost differential not included in the 20-year NPV as these costs continue to be recovered beyond the 20-year window.

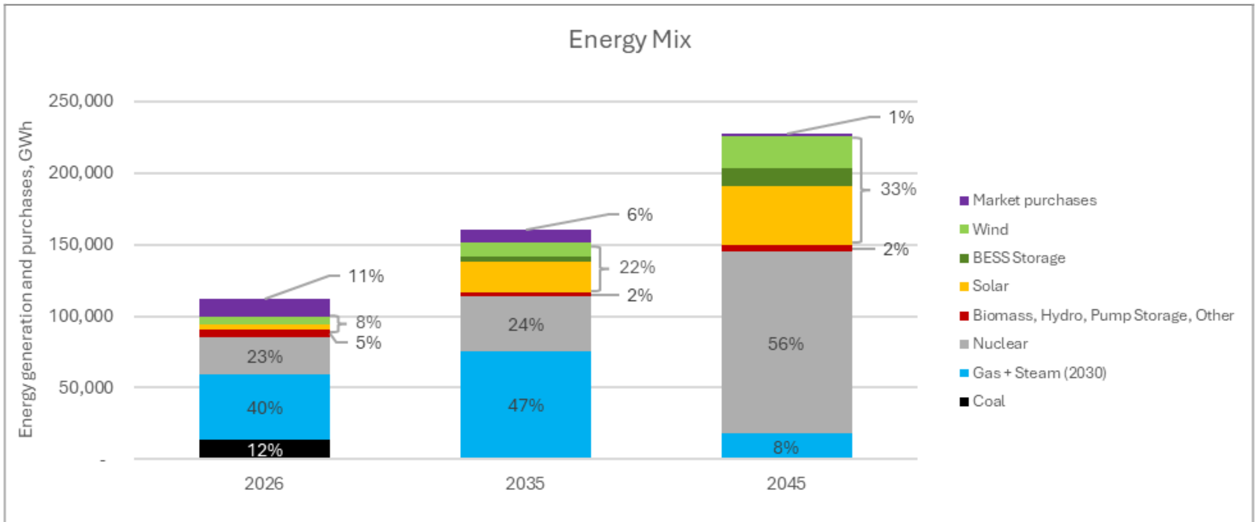
The Company does not consider this to be a feasible Portfolio based on the assumptions beyond reasonable build limits, customer affordability concerns, capital requirements and reliability concerns associated with retiring dispatchable generation during a time of significant load growth. As stated in previous IRPs, achieving the clean energy goals of Virginia, North Carolina, and the Company will require supportive public policies, technological advancements, grid modernization, and broader investments across the economy.

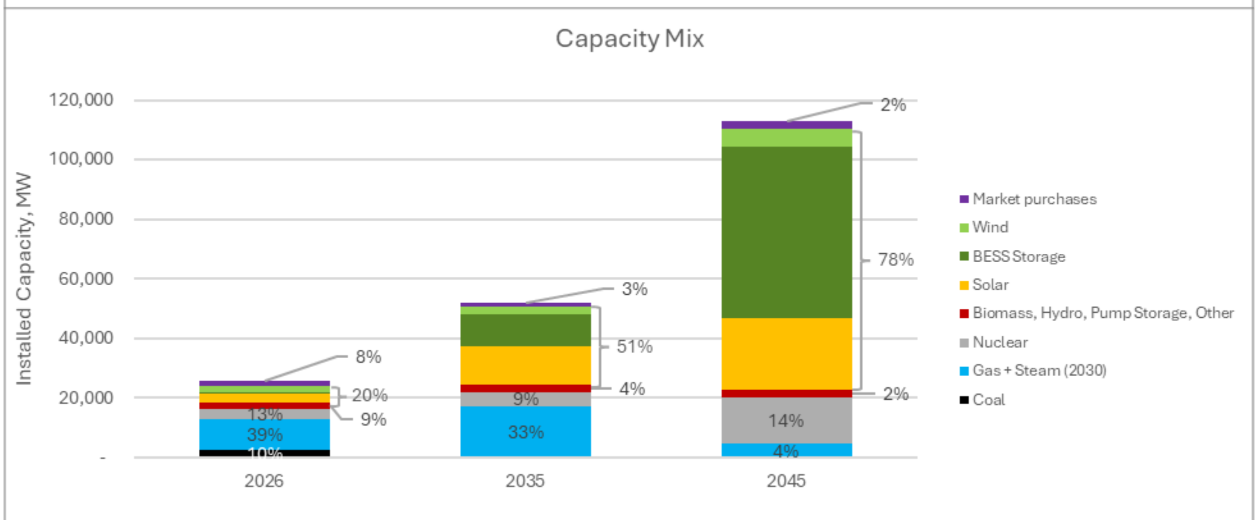
Figure 5.1.1.5: Forced Retirements by 2045

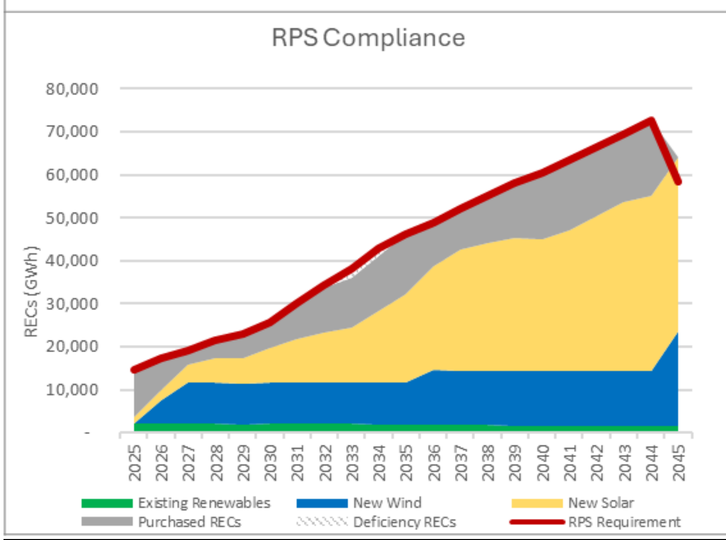
Year	COS Utility Solar	PPA Utility Solar	COS Solar DER	PPA Solar DER	Wind	COS Storage	PPA Storage	LDES Storage (10hr)	Natural Gas-Fired CC	Natural Gas-Fired CT	Nuclear-SMR	Nuclear-Large Scale	Capacity Purchases	Retirements
2026	-	-	-	-	-	-	-	-	-	-	-	-	2,100	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	2,700	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	2,900	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	2,800	-
2030	483	75	36	30	-	200	125	-	-	-	-	-	3,000	-
2031	453	185	45	30	-	100	250	-	-	-	-	-	3,700	-
2032	453	185	57	30	60	100	250	-	-	882	-	-	3,700	-
2033	453	185	66	30	-	100	250	-	1,466	-	-	-	2,900	-
2034	453	1,625	72	30	-	150	200	-	1,466	-	648	-	1,200	-
2035	453	1,625	75	30	-	150	200	-	-	-	648	-	1,300	-
2036	453	1,650	79	30	800	150	200	350	-	-	648	-	800	-
2037	453	1,650	82	30	-	150	200	350	-	-	648	-	600	-
2038	453	330	88	30	-	150	200	350	-	-	648	-	400	-
2039	459	210	88	30	-	150	200	350	-	-	648	-	-	-
2040	-	-	-	-	-	-	350	350	-	-	648	-	-	-
2041	-	1,260	-	-	-	-	350	350	-	-	648	-	1,200	(2,436)
2042	-	1,860	-	-	-	-	350	350	-	-	648	-	800	-
2043	-	2,040	-	-	-	-	350	350	-	-	648	-	1,400	(1,485)
2044	-	1,140	-	-	-	-	350	350	-	-	648	2,234	2,400	(4,579)
2045	-	180	-	-	2,600	-	350	350	-	-	648	2,234	2,600	(4,205)
Total	**4,566**	**14,200**	**688**	**300**	**3,460**	**1,400**	**4,175**	**3,500**	**2,932**	**882**	**7,776**	**4,468**	**36,500**	**12,705**

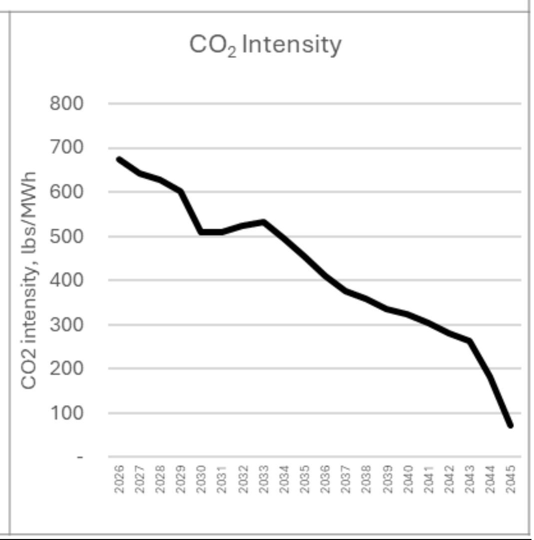
Notes: “COS” = cost of service; “PPA” = power purchase agreement; “DER” = distributed energy resources, whether Company-owned or PPA; “Wind” includes both on and offshore wind units.

Forced Retirements by 2045 Portfolio Dashboard









5.2 Secondary Portfolio

In addition to the three Primary Portfolios presented in this 2025 IRP Update, the Company includes a Secondary Portfolio developed using build limits and planning parameters suggested by the NCUC Public Staff. The inclusion of this Secondary Portfolio ensures that the IRP remains aligned with jurisdictional expectations while providing a robust framework for assessing reliability, affordability, and environmental considerations across a range of plausible futures. As with the Primary Portfolios, the Company has applied consistent modeling assumptions to the Secondary Portfolio to ensure comparability and transparency in its evaluation.

Table 5.2.1: Secondary Portfolio Modeling Results Summary

	NCUC Directed
Net Present Value ("NPV") Total ($B)	$147.9
Approximate CO_2 Emissions from Company in 2045 (Metric Tons)	38.0
Solar (MW)	22,274
Wind (MW)	3,460
Storage (MW)	2,950
Nuclear (MW)	1,620
Natural Gas Fired (MW)	8,510
Retirements (MW)	-

NCUC Directed

The Company worked with the NC Public Staff to model a Secondary Portfolio with different annual solar and storage limits as directed by the NCUC Order for the 2023 IRP and updated by the NCUC order for the 2024 IRP. This Portfolio, the NCUC Directed Portfolio, models a variation of the Company Preferred Plan, in which solar and storage build limits are ramped up over the course of the 20-year planning period. Those build limits can be found in Table 5.2.1. In addition, large-scale nuclear, long duration energy storage in the form of a 10-hour battery, and solar+storage hybrid technology was made available to the model for selection with the model choosing not to select any of these resources. In summary, this Portfolio builds over 22 GW of solar, almost 3 GW of storage, and 3.4 GW of offshore wind. This Portfolio also includes the development of five SMRs, and 8.5 GW of gas fired assets to address future capacity, energy, and system reliability needs. The model did not choose to retire any generation in this Portfolio.

Table 5.2.2: Secondary Portfolio Modeling Results Summary

Year	COS Utility Solar	PPA Utility Solar	COS Solar DER	PPA Solar DER	Wind	COS Storage	PPA Storage	LDES Storage (10hr)	Solar+Storage	Natural Gas-Fired CC	Natural Gas-Fired CT	Nuclear-SMR	Nuclear-Large Scale	Capacity Purchases	Retirements
2026	-	-	-	-	-	-	-	-	-	-	-	-	-	2,100	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	2,700	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	2,900	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	2,800	-
2030	483	555	36	30	-	100	125	-	-	-	-	-	-	3,000	-
2031	453	605	45	30	-	100	25	-	-	-	-	-	-	3,800	-
2032	453	605	57	30	60	100	25	-	-	-	882	-	-	3,700	-
2033	453	785	66	30	-	100	25	-	-	1,466	-	-	-	2,900	-
2034	453	785	72	30	800	150	100	-	-	1,466	-	-	-	1,700	-
2035	453	785	75	30	-	150	100	-	-	-	882	-	-	1,800	-
2036	453	750	79	30	-	150	100	-	-	-	882	-	-	1,700	-
2037	453	750	82	30	-	150	100	-	-	1,466	-	-	-	1,200	-
2038	453	1,050	88	30	-	150	100	-	-	1,466	-	-	-	600	-
2039	459	1,050	88	30	2,600	150	-	-	-	-	-	-	-	500	-
2040	-	1,500	-	-	-	-	-	-	-	-	-	-	-	1,100	-
2041	-	1,500	-	-	-	-	-	-	-	-	-	324	-	1,200	-
2042	-	1,500	-	-	-	-	-	-	-	-	-	324	-	1,400	-
2043	-	1,500	-	-	-	-	-	-	-	-	-	324	-	1,500	-
2044	-	1,500	-	-	-	-	-	-	-	-	-	324	-	1,700	-
2045	-	1,500	-	-	-	-	950	-	-	-	-	324	-	1,600	-
Total	**4,566**	**16,720**	**688**	**300**	**3,460**	**1,300**	**1,650**	**-**	**-**	**5,864**	**2,646**	**1,620**	**-**	**39,900**	**-**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units

Table 5.2.3: NPV results for the Secondary Portfolio

($B)	NCUC Directed
Total System Costs	$121.0
Grid Plan (Net of Benefits)	$(2.2)
SUP	$0.8
Transmission	$28.3
Total Plan NPV	$147.9
Portfolio Delta vs. Least Cost VCEA Compliant Portfolio	$(0.8)

Notes: As previously ordered by the SCC, this figure includes incremental cost estimates associated with transmission and distribution investments. All costs are estimates and will vary based on the actual generation, transmission, and distribution infrastructure developed to meet customer needs. (1) Total system costs include the results from Figures 5.1.1.3 through 5.1.1.5 plus approved, proposed, future, and generic DSM, as applicable; costs related to environmental laws and regulations; renewable energy integration costs; and REC banking as discussed in Appendices 2E, 3D, 5A, and 5B. (2) All NPVs are calculated with a 6.62% discount rate. (3) Numbers may not add due to rounding.

5.3 Sensitivity Analyses

The Company conducted sensitivity analyses for this 2025 IRP Update to show the potential paths forward under different future conditions consistent with SCC and NCUC requirements.

First, the Company conducted sensitivities using different load forecasts. "High" and "Low" load forecasts were developed using the same methodology as described in the 2024 IRP. The high load forecast sensitivity starts out 1.4% higher than the PJM Derived Load Forecast in the first year, moving to 14.3% higher by 2045. The low load forecast sensitivity is 1.4% lower than the PJM Derived Load Forecast in the first year, moving to 14.3% lower by 2045. The Company also ran a sensitivity using the 2025 Company Load Forecast. Figure 5.3.1 shows the results of these sensitivities.

Figure 5.3.1: 2025 Plan Sensitivities on Load Forecast

	Company Preferred Plan/PJM Derived Load Forecast	High Load Forecast Sensitivity	Low Load Forecast Sensitivity	Company Load Forecast Sensitivity
NPV Total ($B)	148.7	169.8	132.8	145.7
Approximate CO_2 Emissions from Company in 2045 (Metric Tons)	39.9	42.0	35.3	38.9
Solar (MW)	17,534	17,534	17,534	17,534
Wind (MW)	3,460	3,460	3,460	3,460
Storage (MW)	2,000	4,350	2,000	2,000
Nuclear (MW)	1,944	3,564	-	1,944
Natural Gas Fired (MW)	8,510	8,926	8,510	8,510
Retirements (MW)	-	-	-	-

The Company also conducted modeling sensitivities utilizing the PJM Derived Load Forecast with different input or commodity price assumptions. First, the Company conducted a sensitivity named the REC RPS Only Sensitivity. The assumptions for this model run are that it meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA, but it is not intended to be fully VCEA compliant and ignores the VCEA development targets. This model run is intended to be used for cost comparison purposes only.

Next, the Company ran several input variations on the Company Preferred Plan to show the effect on NPV using a range of possible costs. To provide sensitivities on fuel, energy, capacity, and REC prices, the Company used two commodity price forecasts produced by ICF—the High Fuel Price commodity forecast and the Low Fuel Price commodity forecast. The Company also ran a sensitivity that increased and decreased the projected capital construction costs of different resources by 10%.

Finally, the Company conducted a sensitivity that assumes the Commonwealth returns to RGGI. For this sensitivity, the Company used a commodity price forecast that assumes Virginia returns to RGGI and includes a RGGI-related cost adder on all Virginia carbon-emitting generators.

See Appendix 5B for a description of these forecasts and the interrelated nature of these commodity prices.

Figure 5.3.2: 2025 Portfolio Sensitivities

Sensitivities	NPV Total ($B)
Company Preferred Plan	$ 148.7
Least Cost RPS Only	$ 143.9
High Fuel	$ 167.8
Low Fuel	$ 135.4
High Capital Construction Costs	$ 151.7
Low Capital Construction Costs	$ 145.0
RGGI	$ 158.5

5.4 Extreme Weather Analysis

The Company models normal weather for planning purposes. As discussed in the 2024 IRP, extreme weather events like abnormal cold or abnormal heat, are becoming increasingly frequent and more intense and addressing these events is an important part of prudent utility planning and system design.

The Company conducted a sensitivity analysis to test the Company Preferred Plan under an extreme weather scenario.[26] The inputs for this extreme weather scenario were derived from PJM's summer and winter extreme weather (90/10) peak load forecast, which can be found in tables D1 and D2 of PJM's 2025 Load Forecast Report.[27] In order to utilize this forecast, the Company Preferred Plan was locked in PLEXOS, and the load forecasts for the years 2035 and 2045 were replaced with the higher 90/10 PJM load forecast. The 90/10 load forecast increased summer and winter peaks (*i.e.*, approximately 2,000 MW for summer peaks and as high as approximately 1,500 MW for winter peaks), as well as the hourly energy requirements. The model was given the same resources as the Company Preferred Plan but was required to dispatch hourly based on the higher 90/10 load forecast. This extreme weather scenario tested the robustness, in regard to meeting hourly energy requirements, of this Portfolio because the model was not able to reoptimize the build plan to account for the higher load forecast.

The results of the extreme weather scenario showed that while the Company Preferred Plan would be short annual capacity resources, the hourly energy needs largely could be met using the resources procured in this Portfolio. The annual capacity needs would require an additional 700 MW of capacity purchases in 2035, and an additional 900 MW of capacity purchases in 2045. As an initial matter, this level of capacity purchases may not be available. If the Company could procure this level of capacity purchases, it would most likely result in higher capacity prices and higher customer costs.

[26] The Company has not seen any evidence of an increase in forecast error related to extreme weather events. The Company continues to forecast peaks and energy using assumed "normal" weather using a 15-year rolling average and addresses the impact of extreme weather in the various scenarios produced in the PLEXOS modeling process.

[27] PJM Interconnection, L.L.C., *PJM Load Forecast Report* (Jan. 2025), available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

The extreme weather modeled in 2035 represents a year with more than 5,500 MW of peak load growth versus 2025. The Company chose 2035 because it aligns with the end of the VCEA's development targets for solar, onshore wind, and energy storage resources and allows the Company to test the system's reliability. Due to the significant resource build in the Company Preferred Plan, the model showed no unserved energy in either summer or winter peak periods. The model was only able to meet this higher load requirement due to the additional renewable resources as well as almost 4,700 MW of dispatchable generation (advanced class CCs and simple cycle CTs).

Without these new resources, particularly those that can dispatch whenever needed, the model would likely see significant energy shortages in both winter and summer. The extreme weather modeled in 2045 represents a year with more than 11,800 MW of peak load growth compared to 2025. Similarly, the model was again able to meet peak load needs by continuing to add renewable as well as an additional 3,800 MW (from 2036-2045) of dispatchable generation and almost 2,000 MW of new nuclear generation. These resources, which are available for dispatch day or night, are essential to meet energy needs.

PJM's capacity market continues to signal the need for more dispatchable resources to ensure adequate reliability for future extreme weather events like those contemplated in PJM's 90/10 load forecast. The high ELCC value of dispatchable resources, coupled with higher capacity pricing in the DOM Zone, produces a build plan that prioritizes resources that can respond well during extreme weather events. The Company will continue to monitor future load growth and consider the impacts extreme weather may have on system reliability.

5.5 Retirement Analysis

The VCEA mandates the retirement of carbon-emitting generation in 2045 on a specific schedule unless the Company petitions and the SCC finds that a given retirement would threaten the reliability and security of electric service to customers. Separate from these mandates, the Company completed two analyses related to retirement of existing units. First, the Company completed a 20-year cash flow analysis focused on coal-fired, biomass-fired, and large CC generation facilities under market conditions. The Company evaluated 20-year cash flows under two Primary Portfolios, the Company Preferred Plan and the Least Cost VCEA Compliant without EPA Portfolio. Unit NPVs were derived by comparing the unit costs, including operations and maintenance and capital, to the total forecasted unit benefits, consisting of energy and capacity revenues (and REC revenues where applicable) for the next 20 years based on the snapshot in time when the analysis was conducted. The results of the 20-year cash flow analysis are included in Figure 5.5.1.

Figure 5.5.1: 20-year cash flow retirement analysis
(in millions)

Units	Company Preferred Plan	Least Cost VCEA Compliant without EPA	Est. T&D Impact
Clover 1 - 2	$792	$892	$0
Mt Storm 1 - 3	$3,818	$4,305	$0
Virginia City Hybrid Energy Center	$711	$1,659	$0
Altavista	$74	$20	$0
Hopewell	$81	$30	$0
Southampton	$94	$41	$0
Rosemary	$78	$80	$0
Bear Garden	$2,341	$1,768	$0
Brunswick	$6,298	$4,758	$3.3
Chesterfield 7 - 8	$1,476	$1,056	$0
Gordonsville 1 - 2	$809	$583	$0
Greensville	$7,892	$6,104	$0
Possum Point 6	$2,784	$2,096	$0
Warren	$5,810	$4,441	$0

Note: "Est. T&D Impact" represents the approximate transmission and distribution upgrades that would be necessary to support the unit retirement individually. This avoided cost is not included in the NPVs shown. In addition, the estimated T&D Impact costs rise to approximately $482 million if considering the cumulative impact of retirement of all of the units.

Second, as directed by the SCC, the Company included the same unit-specific data for the units listed in Figure 5.5.1 in PLEXOS to allow the model to optimize the timing of unit retirements. The Company presents these results as part of the two Primary Portfolios, which shows all units running through the Planning Period. All units have a positive NPV under all scenarios and PLEXOS did not select to retire any units.

It is worth noting that a twenty-year cash flow analysis is not the only deciding factor in retiring an existing resource. This analysis allows the Company to view each unit's near-term projected revenue and cost streams in one place, and to determine key drivers for unit profitability. A positive NPV result indicates that the unit is currently better than the market, while a negative value indicates the unit is currently worse than the market. These results alone are not the exclusive determinants to consider when determining whether to continue to operate an existing unit.

Other quantitative and qualitative considerations must be prudently factored into such determinations, such as remaining useful life, capacity and energy replacements, system reliability, fuel contracts, transmission system considerations, personnel, impact of continued operation of the unit(s) on the local economy, and pending environmental regulations, to name a few. Modeling in this 2025 IRP Update is based on normal weather and models the complete system, which does not fully capture the value of a unit that may be based on location, fuel diversity, value in extreme weather scenarios, operational flexibility, and black start capability, among other factors. The Company has not made any decision regarding the retirement of any current generating unit and does not anticipate any such retirements before 2045. Appendix 3B-10 lists the generating units considered for potential retirement in the Company Preferred Plan.

Chapter 6. Serving Our Communities

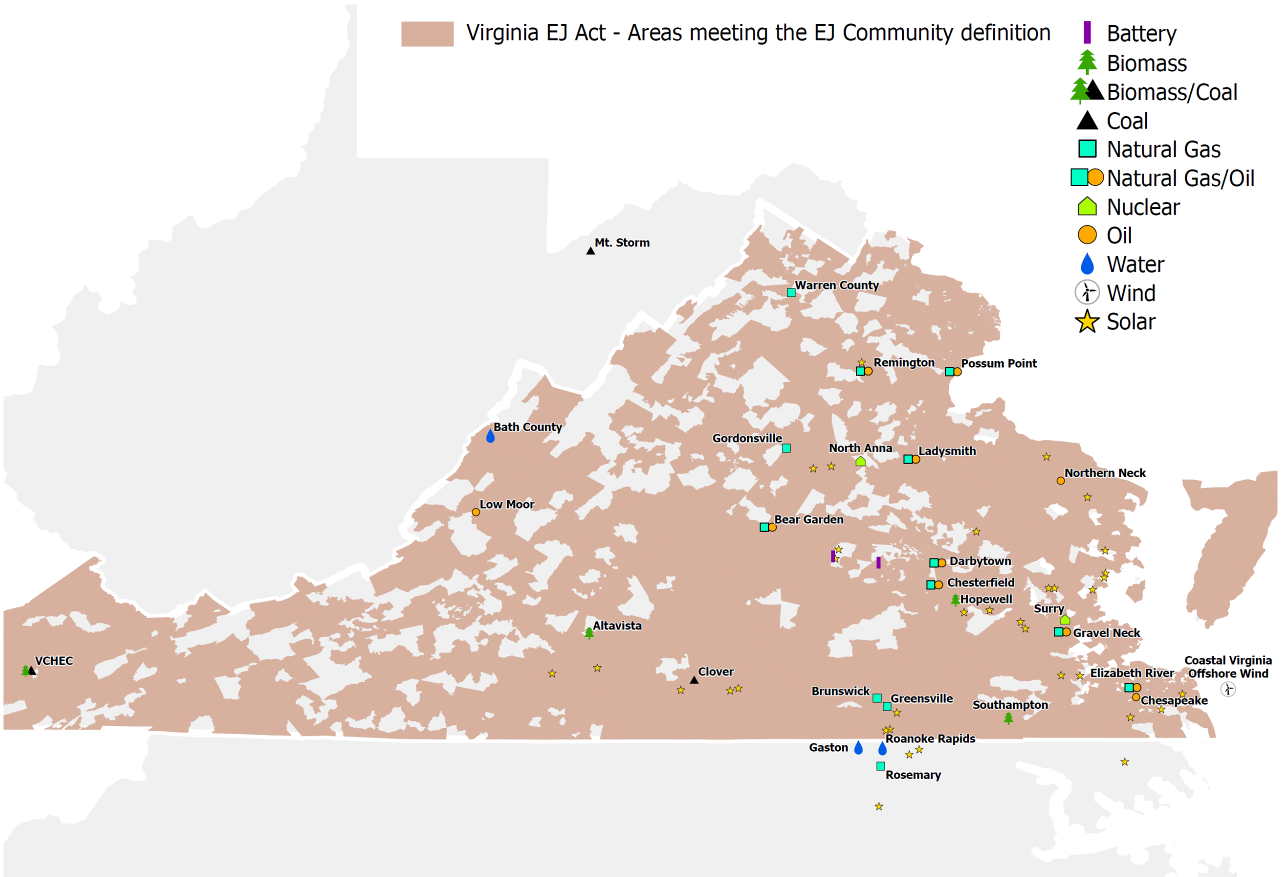
Dominion Energy's environmental justice ("EJ") policy commits to making EJ considerations part of our everyday decision-making. EJ reviews are undertaken for all major projects. We work closely with all appropriate federal, state, local, and tribal agencies to mitigate environmental impacts through the required permitting, approval, or consultation processes.

The Company is committed to delivering excellent customer experience. The key to achieving this goal is educating customers about their energy consumption and how to manage their costs. Our customer education initiatives include providing demand and energy usage information, educational opportunities, and online support options to assist customers in managing their energy consumption and taking advantage of new incentives and offerings in both Virginia and North Carolina.

6.1 Environmental Justice

The Company remains committed to making environmental justice considerations part of our everyday decision-making as we work to deliver reliable, affordable, and increasingly clean energy to our customers in Virginia and North Carolina. The Company continues to follow its EJ policy and the Virginia Environmental Justice Act ("VEJA") in its reviews for all major projects, regardless of whether doing so is required for permitting or other regulatory approvals. See Chapter 6.1 and Appendix 6A of the 2024 IRP for additional details on the Company's EJ policy, the VEJA, and the Company's process for evaluating EJ. Figure 6.1.1 below is an updated map showing the Company's generation resources along with geographic areas that met the definition of EJ community in 2024.

Figure 6.1.1: VEJA EJ Community Map with the Company's Generation Resources



6.2 Customer Education

The Company is committed to delivering an excellent customer experience. The key to achieving this goal is educating customers about their energy consumption and how to manage their costs, empowering them to take advantage of the numerous enhanced capabilities enabled by the Grid Transformation Plan and other initiatives.

The Company's customer education initiatives include providing demand and energy usage information, educational opportunities, and online support options to assist customers in managing their energy consumption and taking advantage of new incentives and offerings. The educational initiatives apply to the Company's customers in both Virginia and North Carolina.

Website and Supporting Print Collateral

The Dominion Energy website—https://www.dominionenergy.com—serves as a central hub for public education. The Company offers program- and project-specific information, factsheets, brochures, videos, and other supporting documents to provide background and updates on the benefits and enhanced capabilities associated with various investments and initiatives. These include, but are not limited to, approved elements of the Grid Transformation Plan, major infrastructure projects, and new offerings such as rates, tools, and mobile apps as they become available.

Social Media

The Company uses the social media channels of X® and Meta® to provide real-time updates on energy-related topics, promote Company messages, and provide two-way communication with customers. The Company also manages pages on YouTube® and Instagram for further outreach to the general public, residential customers, and business customers. LinkedIn® is leveraged for reaching commercial and industrial customers.

The Company's X® account is available online at: https://x.com/dominionenergy.
The Company's Facebook® account is available online at:
https://www.facebook.com/dominionenergy.
The Company's YouTube® account is available online at
https://www.youtube.com/dominionenergy.
The Company's Instagram® account is available online at
https://www.instagram.com/dominionenergy/.
The Company's LinkedIn® account is available online at
https://www.linkedin.com/company/dominionenergy/.

News Releases

The Company prepares news releases and reports on the latest developments regarding its customer-facing initiatives and provides updates on Company offerings and recommendations for saving energy as new information and programs become available. Current and archived news releases can be viewed at: https://news.dominionenergy.com/.

Energy Conservation Programs

The Company's website has a section dedicated to energy conservation that contains helpful information for both residential and non-residential customers, including information about the Company's DSM programs. Dozens of programs are featured on the website, and include eligibility guidelines, program details, steps to enroll, and success stories, as well as contact information to speak with program specialists. Through consumer education using a variety of channels to reach multiple customer classes, the Company is working to encourage the adoption of energy-efficient technologies in residences and businesses in Virginia and North Carolina. A multi-channel marketing strategy, including radio, print, digital, and out-of-home channels helps drive adoption, education, and awareness of the Company's DSM programs. A website for programs in Virginia is maintained at https://www.dominionenergy.com/virginia/save-energy. A website for programs in North Carolina is available at https://www.dominionenergy.com/north-carolina/save-energy.

Community Outreach – Trade Shows, Exhibits, and Speaking Engagements

Dominion Energy conducts outreach seminars and speaking engagements to share relevant energy conservation program information to both residential and commercial audiences. The Company also participates in various trade shows, exhibits and community events to educate customers on the Company's programs and inform customers and communities about the importance of implementing energy-saving measures in homes and businesses and taking advantage of new rates and offerings as they become available. Company representatives positively impact the communities the Company serves through presentations to elementary, middle, and high school students about its programs, wise energy use, and environmental stewardship. Additional partnerships with the educational community are offered through mentoring initiatives, philanthropic support, and other means to strengthen science, technology, engineering, and mathematics competitiveness to help prepare students for tomorrow's careers. Information on educational grants, scholarships, and programs for teachers and students is available on the Company's website at:
https://www.dominionenergy.com/our-company/customers-and-community/educational-programs.

6.3 Economic Development Rates (for qualifying customers)

As of October 2025, the Company has six customer locations in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 79.2 MW. As of October 2025, the Company has one customer in North Carolina receiving service under an economic development rate. The total load associated with this rate is approximately 2 MW.

Dominion Energy Virginia and North Carolina

2025 Integrated Resource Plan (IRP) Update: Stakeholder Process Report

Background

In 2023, the Virginia General Assembly enacted legislation (the "Legislation") that, among other provisions, directed Virginia Electric & Power Company ("Dominion Energy" or the "Company"), when preparing its Integrated Resource Plan ("IRP"), to "engage the public in a stakeholder review process and provide opportunities for the public to contribute information, input, and ideas, including the plan's development methodology, modeling inputs, and assumptions, as well as the ability for the public to make relevant inquiries."[1]

In 2024, the Company conducted its first IRP stakeholder process under the new legislation. Building on lessons learned from the 2024 process and feedback from last year's participants, the Company refined its approach by focusing the stakeholder meetings on topics critical to the 2025 IRP Update and on input needed from stakeholders to refine the Stakeholder Input Case. These virtual meetings, along with other engagement tools – discussed later in this report – were aligned with key internal planning milestones, allowing stakeholders to provide timely feedback on modeling assumptions, scenario development, and resource options under consideration. This approach helped ensure that stakeholder perspectives were meaningfully considered in the 2025 IRP Update.

In this Stakeholder Process Report ("Report"), Dominion Energy outlines its stakeholder engagement efforts and describes how it worked to involve a broad array of stakeholders throughout the development of the 2025 IRP Update. The Report includes a detailed account of the stages of the stakeholder process, the methods used to gather input, and initiatives aimed at ensuring broad participation. It also presents a narrative summary of the feedback received – both quantitative and qualitative – that informed the Stakeholder Input Case for the 2025 IRP Update.

It is important to note that this Report, while reflective of the Company's efforts, is solely the work of Dominion Energy and does not represent the review or endorsement of any participating stakeholders. The Company views stakeholder engagement as an evolving process and remains committed to continuous improvement in future IRP cycles to better reflect stakeholder priorities and policy developments.

Objectives

Consistent with the requirements of the Legislation enacted by the Virginia General Assembly, Dominion Energy developed a set of core objectives to guide its Stakeholder Process for the 2025 IRP Update. Specifically, the Company aimed to:

- Engage the public in a review process including representatives from multiple interest groups.
- Provide opportunities for the public to contribute information, input, and ideas on the utility's 2025 IRP Update, including the IRP Update's development methodology, modeling inputs, and assumptions.
- Provide the ability for the public to make relevant inquiries to the utility when formulating its IRP Update.

[1] This requirement is codified at Va. Code § 56-599 D.

To achieve these objectives, the Company established a series of commitments to stakeholders aimed at encouraging broad participation and integrating diverse perspectives into the IRP. These commitments were designed to create a collaborative framework that not only fulfilled statutory requirements but also set realistic and meaningful goals for the stakeholder process. They are as follows:

- Provide multiple opportunities for stakeholder input during the IRP Update process;
- Capture a wide spectrum of stakeholder input, reflecting the diverse interests and feedback of parties involved;
- Carefully consider all input and diverse perspectives provided;
- Meet all legislative, regulatory and operational requirements;
- Maintain 24x7x365 reliability; and
- Respond to questions relevant to the 2025 IRP Update provided they do not involve highly sensitive or confidential information.

Stakeholder Identification

For the 2025 IRP Update Stakeholder Process, Dominion Energy utilized its 2024 stakeholder list, which included participants from past IRP proceedings; staff from the Virginia State Corporation Commission ("SCC") and North Carolina Utilities Commission ("NCUC"); other local, state, and federal officials; non-governmental organizations; tribal nations; nonprofit groups; the military and defense sector; labor unions; businesses and large energy users; and individual citizens, among others.

To expand outreach and encourage participation from new stakeholders, the Company once again published public notices in 27 newspapers in Virginia and 23 newspapers in North Carolina. These notices were strategically placed to reach a broad geographic and demographic audience, including underserved and rural communities.

Public Notice

Dominion Energy 2025 Integrated Resource Plan Stakeholder Process

Dominion Energy is preparing an update to its 2024 Virginia and North Carolina Integrated Resource Plan (IRP), which is a planning document that outlines how the company intends to reliably meet customers' long-term energy and capacity needs. As part of this effort, Dominion Energy is seeking stakeholder input and will be hosting virtual stakeholder meetings to gather comments from interested parties.

If you are interested in participating, please contact devirp@devirp.dominionenergyinfo.com and include your name, contact number, the organization you represent (if applicable), and a brief description of your interest in the IRP.

7/24/25

In total, the Company had engaged approximately 126 individual stakeholders by the final stakeholder meeting.

Stakeholder Engagement Opportunities

The 2025 IRP Stakeholder Process consisted of four virtual meetings (described in the next section) and leveraged digital tools to encourage both quantitative and qualitative stakeholder input.

A key enhancement in this year's process was the introduction of an online survey to collect feedback on the Stakeholder Input Case, allowing participants to review proposed assumptions and scenarios privately. The survey included questions on resource build limits, policy considerations, and other planning elements. It remained open for one week, providing stakeholders time to provide thoughtful input. A total of 15 stakeholders from 13 unique organizations responded, and their feedback was analyzed and incorporated into the planning process to ensure stakeholder perspectives were reflected in the IRP Update's development.

To further support stakeholder engagement, Dominion Energy continued to use the dedicated website and email address.

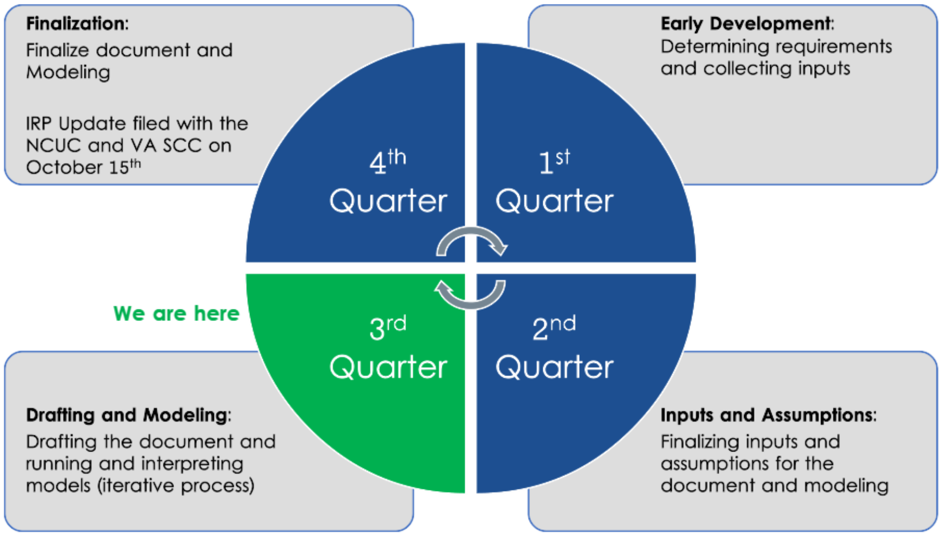
The website (https://devirp.dominionenergy.com) provided comprehensive information on the IRP stakeholder process, including meeting dates, presentation materials, and recordings. It also featured a Q&A section with stakeholder questions and Company responses, as well as a feedback form for submitting input, ideas, and inquiries at any time. The dedicated email address offered another direct channel for communication.

By focusing discussions on critical topics and offering multiple avenues for input, Dominion Energy ensured stakeholders could contribute meaningfully without an undue time commitment. The Company plans to maintain these engagement tools in future planning cycles, reinforcing its commitment to collaboration and continuous improvement.

Kick-Off Meeting

On August 1, 2025, Dominion Energy convened the first stakeholder meeting for the 2025 IRP Update, marking the launch of this year's engagement process. The meeting served as an opportunity to inform stakeholders of key developments since the 2024 IRP, including revised electricity demand forecasts, updated assessments of resource adequacy, and adjustments reflecting evolving market conditions.

With approximately 46 participants joining virtually, Dominion Energy began by outlining the goals and structure of the 2025 Stakeholder Process. The Company presented a timeline aligned with internal planning milestones and emphasized the iterative nature of IRP development, underscoring the importance of timely stakeholder input.



The meeting also included a discussion of the differences between a full IRP filing and an IRP update year, as well as a high-level summary of the SCC and NCUC's 2024 IRP Orders. Dominion Energy reiterated its commitment to incorporating diverse perspectives, meeting all legislative and regulatory requirements, and providing multiple avenues for stakeholder engagement.

To conclude, the Company held an open Q&A session, reviewed the next steps in the process, and introduced a forthcoming survey designed to collect feedback on updated modeling inputs and assumptions for the Stakeholder Input Case. Participants were encouraged to remain engaged throughout the process, both through future meetings and the stakeholder website.

Meeting on Modeling Inputs & Reliability

On August 27, Dominion Energy held a "Modeling & Reliability Meeting" based on themes, areas of interest, feedback and questions expressed by stakeholders during the Stakeholder Process. Scheduled early in the engagement timeline, the meeting was intended to provide the Company with sufficient time to incorporate stakeholder input into the modeling of the 2025 Stakeholder Input Case. Invitations were sent to 234 stakeholders on August 13, followed by a reminder email on August 20. A total of 39 stakeholders attended the meeting.

The meeting began with three brief presentations from Dominion Energy subject matter experts ("SMEs"). The first presentation provided an overview of the 2025 PJM Load Forecast, noting changes from the 2024 forecast and highlighting a slight increase in load within certain Load Serving Entities ("LSEs") within the Dominion Zone ("DOM Zone"). The Company also shared its methodology for deriving the Dom LSE forecast from PJM's DOM Zone forecast and identified key drivers of change, including data center growth, demand-side management, and electric vehicle adoption.

Next, the Company presented on energy supply, beginning with insights from PJM's 2026–2027 Base Residual Auction. The record clearing price was discussed as an indicator of tightening supply and demand conditions in the region, driven by load growth and resource retirements. The Company also reviewed updated Effective Load Carrying Capability ("ELCC") values provided by PJM and shared expectations for future ELCC trends.

The third presentation focused on energy storage. Dominion Energy discussed storage targets under the Virginia Clean Economy Act ("VCEA"), provided updates on current and pilot storage projects within its service territory, and offered perspectives on the future of long-duration storage technologies.

The meeting concluded with a review of the Stakeholder Input Survey results, followed by an open Q&A session. Subject matter experts were available to respond to stakeholder questions and provide additional details on the information that was presented.

Stakeholder Input Review Meeting

On September 30, 2025, the Company held its Stakeholder Input Review Meeting to provide an update on Stakeholder Q&A and to review the Stakeholder Input Case and other 2025 IRP Update assumptions. Invitations were sent to 246 stakeholders on September 16, followed by a reminder email on September 23. A total of 28 stakeholders attended the meeting.

The Company began with a quick update on where stakeholders could find responses to Q&A received during previous meetings and through the stakeholder website. Then a summary of the 2025 Portfolios was presented. The Company explained the various assumptions that would be included for each of the Portfolios and the Stakeholder Input Case. The assumptions reviewed included the commodity price forecast, the VCEA development targets, retirements, selectable generation resources, build limits, energy efficiency environmental regulations, and capacity imports.

The Company reviewed the types of sensitivities that would be included in the 2025 IRP Update.

Before reviewing the results of the Stakeholder Input Case, the Company reviewed the survey results again. Like the other meetings during the process, the meeting concluded a Q&A session.

Post Filing Meeting

The final stakeholder meeting for the 2025 IRP Update stakeholder process is scheduled for October 24, 2025. At this meeting, the Company plans to provide an overview of its filed 2025 IRP Update. A recording of the presentation will be posted to the Stakeholder Process website.

Stakeholder Survey Results and the Stakeholder Input Case

To gather stakeholder input following the Kick-Off Meeting, Dominion Energy developed a 21-question Microsoft Forms survey titled the "Stakeholder Input Survey." The survey was designed to capture stakeholder preferences on modeling inputs and assumptions relevant to the updated 2025 IRP Stakeholder Input Case. The questionnaire was sent to 234 stakeholders on August 14 and remained open through August 21. A reminder email was sent to stakeholders on August 19 to encourage more responses before the deadline.

Stakeholders were informed that the Company would model a single Stakeholder Input Case, and as such, not all suggested options could be incorporated. Additionally, responses from the same organization could be aggregated to streamline analysis.

The Company received 15 responses to the survey, representing a 6.4% response rate. Many of the responses aligned with the modeling inputs and assumptions used in the 2024 Stakeholder Input Case, though some reflected evolving stakeholder perspectives. Notably, stakeholders were divided evenly on retirement assumptions. Survey results showed that 45% of respondents supported maintaining model-optimized retirements, while another 45% favored forced retirements of applicable emitting resources by 2045. Since the 2024 Stakeholder Input Case utilized a least-cost optimized approach and due to the 2025 IRP Update containing a Portfolio to show forced retirements by 2045, the Company retained the assumption to allow the model to select retirements based on a least-cost optimized approach.

Summary: Stakeholder Input Case Model Inputs

Dominion Energy

	2024 Stakeholder Case	2025 Stakeholder Case
Meets RPS Program (i.e., REC retirements) Requirement?	Yes	Yes
Forced VCEA Development Targets?	Yes	Yes
Renewable Utility/PPA	65/35	65/35
REC Purchases	30%	30% *
EPA Environmental Regulations	Yes	Yes
Solar Build Limits (MW)	2,040	2,040
Storage Build Limits (MW)	700	700
Onshore/Offshore Wind (MW)	60 / 6,000	60* / 6,000
Nuclear Build Limits (starting in 2034) (MW)	536	Large-scale and SMR resources selectable
Natural Gas Resources	None	None
Capacity Imports (Purchases) (MW)	5,000	5,000
Energy Imports	20% of Annual	20% of Annual *
Retirements	Least Cost Optimized	Split **
Load Forecast	PJM	
EE	Aligned with goals est. in SCC's pending target setting proceeding; Beyond 2028 based on proposed targets w/reasonable increase based on savings potential.	

In addition, 2025 stakeholders requested long-duration energy storage (LDES) and hybrid solar plus storage resources be selectable resources. Stakeholders also support modeling Virginia in RGGI.

*or align with Primary Portfolios
**even split between least-cost and VCEA-forced retirements

27

The Company shared the results of the survey with stakeholders during the August 27 "Modeling & Reliability Meeting" and further reviewed the modeling inputs and assumptions for the Stakeholder Input Case at the "Stakeholder Input Review Meeting" held on September 30.

Based on the results of the survey, the majority of stakeholders requested that the 2025 Stakeholder Input Case contemplated VCEA compliance, included no new natural gas-fired generation, and assumes that the Commonwealth rejoins the Regional Greenhouse Gas Initiative ("RGGI"). In response, the Company modeled a plan with these assumptions along with the inputs outlined below:

- Import limits: Survey respondents requested an annual capacity purchase limit of 5,000 MW.

- Build limits: Survey respondents requested that annual solar and storage build limits be doubled to 2,040 MW and 700 MW, respectively. Additionally, the majority of survey respondents requested additional offshore wind beyond the three areas the Company has leases and twice as many SMRs annually.

- Selectable generation resources: Survey respondents requested multiple additional technologies be made available to the model for selection. Long duration energy storage ("LDES") was made available to the model beginning in 2035 and was selected. In addition, large scale nuclear units and solar+storage hybrid units were also made available but were not selected by the model.

By modeling this Stakeholder Input Case, the Company does not submit that it is practicable, realistic, or workable. The Company believes these assumptions to be infeasible. For example:

- Increasing import capability would create significant reliability concerns and would simply shift natural gas generation from being constructed in Virginia to being constructed in another state and having older, less efficient, more heavily polluting fossil units in other states operate more than they would otherwise.

- Increasing build limits to infeasible amounts may have unintended consequences of making projects more difficult to site by prompting additional land use restrictions at the local level, if not outright bans. The incremental cost of adding very large projects within the planning window is also unrealistic.

- As discussed in the Future Supply-Side Resource Options section of the 2025 IRP Update, LDES is still an emerging technology, with projects in various stages of planning and piloting. These projects are intended to validate performance and cost data to support future investment and customer deployment decisions. Without this validation, it is difficult to assess the feasibility of the assumptions utilized in Stakeholder Input Case.

With these important cautions, the Stakeholder Input Case is presented in Figure 1 below.

Combining the incremental resources in this case with the like resources, over the 20-year planning period, the Case includes 27.4 GW of solar, 7 GW of storage, 6 GW of wind, almost 3 GW of SMRs, and requires that the capacity purchase limit be increased to 83.1 GW of capacity purchases to meet customer need.

Figure 1: Stakeholder Input Case

Year	COS Utility Solar	PPA Utility Solar	COS Solar DER	PPA Solar DER	Wind	COS Storage	PPA Storage	LDES Storage (10hr)	Solar+Storage	Natural Gas-Fired CC	Natural Gas-Fired CT	Nuclear-SMR	Nuclear-Large Scale	Capacity Purchases	Retirements
2026	-	-	-	-	-	-	-	-	-	-	-	-	-	2,100	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	2,600	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	2,800	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	2,600	-
2030	483	75	36	30	-	100	250	-	-	-	-	-	-	2,900	-
2031	453	185	45	30	-	100	250	-	-	-	-	-	-	3,600	-
2032	453	1,625	57	30	60	100	250	-	-	-	-	-	-	4,200	-
2033	453	1,625	66	30	-	100	250	-	-	-	-	-	-	4,300	-
2034	453	1,625	72	30	-	150	200	-	-	-	-	-	-	4,400	-
2035	453	1,625	75	30	-	150	200	-	-	-	-	-	-	5,000	-
2036	453	1,650	79	30	800	150	200	300	-	-	-	324	-	5,000	-
2037	453	1,650	82	30	-	150	200	350	-	-	-	324	-	5,000	-
2038	453	1,650	88	30	-	150	200	350	-	-	-	324	-	5,000	-
2039	459	1,650	88	30	2,600	150	200	350	-	-	-	-	-	4,700	-
2040	-	2,040	-	-	-	-	350	-	-	-	-	324	-	4,800	-
2041	-	2,040	-	-	-	-	350	-	-	-	-	324	-	4,900	-
2042	-	1,500	-	-	-	-	350	-	-	-	-	324	-	5,000	-
2043	-	-	-	-	2,600	-	350	-	-	-	-	324	-	4,600	-
2044	-	1,740	-	-	-	-	350	-	-	-	-	324	-	4,700	-
2045	-	1,200	-	-	-	-	350	-	-	-	-	324	-	4,900	-
Total	**4,566**	**21,880**	**688**	**300**	**6,060**	**1,300**	**4,300**	**1,350**	**-**	**-**	**-**	**2,916**	**-**	**83,100**	**-**

The Company has included these modeling results to be responsive to stakeholder input and appreciates the insights gained from this exercise. However, for the reasons discussed above, the Company does not submit the Stakeholder Input Case as a feasible or achievable path forward for the Company and its customers.

Thank you to Participating Stakeholders

Dominion Energy extends its sincere appreciation to all stakeholders for their meaningful engagement throughout the IRP Stakeholder Process. Your time, thoughtful participation, and constructive feedback have been instrumental in informing the development of the 2025 IRP Update.

Conclusion

Dominion Energy's 2025 IRP Update Stakeholder Process reflects the Company's continued commitment to meeting the requirements of legislation enacted by the Virginia General Assembly in 2023, while also advancing meaningful engagement with stakeholders on energy planning.

Building on lessons learned from the 2024 process and feedback from last year's participants, the Company refined its approach to gather input more efficiently. To support this goal, Dominion Energy hosted four virtual meetings and leveraged digital tools to facilitate stakeholder input and questions. This streamlined format was designed to reduce the time commitment required of participants while still enabling substantive contributions.

Although the 2025 IRP Update is not subject to a formal evidentiary proceeding before Virginia State Corporation Commission and the North Carolina Utilities Commission, the Company provided multiple opportunities for stakeholders to contribute information, provide feedback, and submit inquiries throughout the process. Insights gathered through these channels informed updates to both the Stakeholder Input Case and the broader IRP.

Dominion Energy views stakeholder engagement as an evolving process and remains committed to continuous improvement in future IRP cycles. The Company will continue to refine its approach based on stakeholder feedback, with the goal of creating a process that reflects the priorities, interests, and needs of all participants. By incorporating lessons learned and adapting to stakeholder input, Dominion Energy aims to foster a more inclusive, transparent, and responsive planning process.

Appendix 2B-1: Total (DOM LSE) Sales (GWh) by Customer Class

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2015	30,923	30,282	8,765	10,310	256	1,620	82,157
2016	30,213	31,366	8,495	10,400	257	1,599	82,330
2017	29,581	31,895	8,202	10,855	263	1,515	82,311
2018	32,139	33,591	8,324	10,761	260	1,633	86,707
2019	31,105	34,906	7,230	10,520	262	1,580	85,603
2020	30,154	31,400	6,344	10,665	258	1,439	80,260
2021	30,994	34,974	6,699	10,689	244	1,570	85,170
2022	31,237	39,549	6,401	11,023	232	1,547	89,989
2023	28,704	43,134	5,375	10,996	209	1,488	89,906
2024	30,308	45,684	5,500	11,244	216	1,503	94,455
2025	31,263	49,583	5,632	11,196	229	1,539	99,441
2026	30,576	50,934	5,548	11,143	242	1,529	99,972
2027	30,271	54,093	5,529	11,112	242	1,524	102,772
2028	29,988	57,815	5,507	11,091	242	1,526	106,168
2029	30,014	61,865	5,492	11,070	241	1,506	110,188
2030	30,234	66,238	5,476	11,050	241	1,495	114,734
2031	30,440	70,840	5,460	11,041	241	1,484	119,505
2032	30,567	75,873	5,433	11,038	241	1,483	124,635
2033	30,784	80,750	5,404	11,038	241	1,463	129,681
2034	31,064	85,757	5,368	11,038	241	1,451	134,919
2035	31,352	91,001	5,335	11,038	241	1,445	140,412
2036	31,580	96,750	5,303	11,038	241	1,452	146,364
2037	31,875	101,918	5,281	11,038	241	1,440	151,794
2038	32,161	106,958	5,256	11,038	241	1,437	157,093
2039	32,438	110,806	5,232	11,038	241	1,437	161,193
2040	32,735	115,092	5,203	11,038	241	1,446	165,756
2041	33,109	119,193	5,181	11,038	241	1,441	170,203
2042	33,427	123,723	5,155	11,038	241	1,448	175,033
2043	33,731	128,384	5,129	11,038	241	1,457	179,981
2044	33,987	133,504	5,100	11,038	241	1,476	185,346
2045	34,307	138,039	5,078	11,038	241	1,477	190,181

Note: Historic (2015 - 2024); Projected (2025 - 2045, Jan - Jun actuals used for 2025)
Appendix 2B-1 has been provided with the 2025 Company Load Forecast instead of the 2025 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 2B-2: Virginia Sales (GWh) by Customer Class

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2015	29,293	29,432	7,006	10,181	248	1,567	77,726
2016	28,652	30,537	6,727	10,273	249	1,547	77,985
2017	28,050	31,081	6,512	10,730	255	1,466	78,095
2018	30,437	32,752	6,598	10,633	252	1,581	82,254
2019	29,513	34,091	5,535	10,394	253	1,530	81,317
2020	28,581	30,681	4,750	10,521	250	1,393	76,176
2021	29,392	34,239	4,971	10,540	237	1,519	80,897
2022	29,595	38,781	4,890	10,873	225	1,500	85,864
2023	27,196	42,438	3,921	10,808	201	1,443	86,006
2024	28,742	44,961	4,073	11,052	209	1,458	90,495
2025	29,637	48,828	4,076	10,991	222	1,492	95,246
2026	28,969	50,193	3,967	10,959	235	1,482	95,805
2027	28,679	53,369	4,184	10,918	235	1,477	98,862
2028	28,411	57,103	4,164	10,898	235	1,478	102,289
2029	28,449	61,162	4,064	10,880	235	1,460	106,249
2030	28,681	65,542	4,101	10,857	235	1,449	110,864
2031	28,897	70,146	4,119	10,850	235	1,438	115,684
2032	29,033	75,179	4,186	10,850	235	1,437	120,920
2033	29,259	80,054	4,122	10,852	234	1,418	125,938
2034	29,546	85,057	4,074	10,857	235	1,406	131,176
2035	29,842	90,294	4,018	10,855	235	1,400	136,645
2036	30,076	96,032	3,942	10,857	235	1,407	142,549
2037	30,377	101,188	3,948	10,859	235	1,396	148,004
2038	30,668	106,220	3,993	10,860	235	1,393	153,370
2039	30,948	110,060	3,987	10,862	235	1,393	157,486
2040	31,249	114,338	3,990	10,863	236	1,402	162,077
2041	31,627	118,430	3,994	10,865	236	1,397	166,548
2042	31,948	122,951	3,859	10,867	236	1,403	171,265
2043	32,257	127,603	4,023	10,868	236	1,412	176,399
2044	32,517	132,713	3,963	10,870	236	1,431	181,729
2045	32,842	137,237	3,844	10,872	236	1,431	186,462

Note: Historic (2015 - 2024); Projected (2025 - 2045, Jan - Jun actuals used for 2025)
Appendix 2B-2 has been provided with the 2025 Company Load Forecast instead of the 2025 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 2B-3: North Carolina Sales (GWh) by Customer Class

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2015	1,630	850	1,759	130	8	53	4,431
2016	1,562	829	1,768	128	8	52	4,346
2017	1,531	813	1,690	124	8	49	4,216
2018	1,701	839	1,725	128	8	52	4,453
2019	1,592	815	1,695	126	9	50	4,286
2020	1,573	720	1,593	144	8	46	4,084
2021	1,603	735	1,729	149	7	50	4,273
2022	1,642	768	1,511	150	7	47	4,125
2023	1,509	696	1,455	188	8	46	3,900
2024	1,565	723	1,426	192	8	45	3,960
2025	1,625	755	1,555	205	7	47	4,195
2026	1,607	741	1,581	184	7	47	4,167
2027	1,592	724	1,345	194	7	47	3,909
2028	1,578	712	1,343	193	7	47	3,879
2029	1,565	702	1,428	191	7	47	3,939
2030	1,553	696	1,375	193	7	46	3,870
2031	1,543	694	1,341	190	6	46	3,821
2032	1,534	694	1,247	188	6	46	3,715
2033	1,525	696	1,282	187	7	45	3,742
2034	1,517	700	1,295	181	6	45	3,744
2035	1,510	707	1,316	183	6	45	3,768
2036	1,504	718	1,361	181	6	45	3,815
2037	1,498	730	1,332	180	6	45	3,790
2038	1,494	739	1,262	178	6	44	3,723
2039	1,490	746	1,245	176	6	44	3,707
2040	1,487	754	1,213	175	6	45	3,679
2041	1,482	763	1,187	173	6	45	3,655
2042	1,478	772	1,296	171	6	45	3,768
2043	1,474	781	1,106	170	6	45	3,582
2044	1,470	792	1,136	168	6	46	3,617
2045	1,464	802	1,235	167	6	46	3,719

Note: Historic (2015 - 2024); Projected (2025 - 2045, Jan - Jun actuals used for 2025)
Appendix 2B-3 has been provided with the 2025 Company Load Forecast instead of the 2025 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 2B-4: Total (DOM LSE) Customer Count

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2015	2,252,438	239,623	662	28,923	3,814	3	2,525,463
2016	2,275,551	240,804	654	29,069	3,941	3	2,550,022
2017	2,298,894	242,091	648	28,897	4,149	3	2,574,683
2018	2,323,662	243,701	644	28,716	4,398	3	2,601,124
2019	2,362,949	246,043	634	28,452	4,792	3	2,642,873
2020	2,397,544	246,865	626	29,883	4,889	3	2,679,810
2021	2,427,368	249,622	615	29,845	5,109	3	2,712,562
2022	2,451,831	251,673	610	29,709	5,196	3	2,739,022
2023	2,476,111	253,000	754	31,665	5,185	3	2,766,718
2024	2,492,204	253,128	875	31,732	5,318	3	2,783,259
2025	2,518,624	253,247	895	31,880	5,323	3	2,809,972
2026	2,546,424	252,793	795	32,071	5,462	3	2,837,547
2027	2,573,704	252,243	789	32,214	5,606	3	2,864,560
2028	2,600,461	251,653	783	32,316	5,750	3	2,890,966
2029	2,626,654	251,018	777	32,363	5,894	3	2,916,709
2030	2,652,565	250,360	771	32,386	6,038	3	2,942,122
2031	2,678,431	249,698	765	32,469	6,182	3	2,967,548
2032	2,704,309	249,037	759	32,574	6,326	3	2,993,008
2033	2,730,313	248,386	753	32,677	6,470	3	3,018,602
2034	2,756,584	247,756	747	32,773	6,614	3	3,044,477
2035	2,783,138	247,148	741	32,857	6,758	3	3,070,645
2036	2,809,970	246,562	735	32,926	6,902	3	3,097,098
2037	2,837,093	246,000	729	32,987	7,046	3	3,123,858
2038	2,864,450	245,456	723	33,044	7,190	3	3,150,865
2039	2,891,930	244,921	717	33,099	7,334	3	3,178,004
2040	2,919,464	244,392	711	33,155	7,478	3	3,205,203
2041	2,947,068	243,867	705	33,212	7,622	3	3,232,478
2042	2,974,770	243,351	699	33,267	7,766	3	3,259,856
2043	3,002,561	242,841	693	33,319	7,910	3	3,287,326
2044	3,030,403	242,336	687	33,367	8,054	3	3,314,850
2045	3,058,256	241,831	681	33,411	8,198	3	3,342,380

Note: Historic (2015 - 2024); Projected (2025 - 2045, Jan - Jun actuals used for 2025)
Appendix 2B-4 has been provided with the 2025 Company Load Forecast instead of the 2025 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 2B-5: Virginia Customer Count

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2015	2,150,818	223,946	611	27,070	3,430	2	2,405,877
2016	2,173,472	225,029	603	27,223	3,560	2	2,429,889
2017	2,196,466	226,270	596	27,041	3,768	2	2,454,143
2018	2,220,797	227,757	594	26,872	4,017	2	2,480,039
2019	2,259,491	229,988	584	26,614	4,417	2	2,521,096
2020	2,292,457	230,782	576	27,901	4,516	2	2,556,234
2021	2,321,357	233,334	567	27,836	4,741	2	2,587,837
2022	2,344,903	235,269	563	27,704	4,824	2	2,613,265
2023	2,367,849	236,712	700	29,074	4,806	2	2,639,143
2024	2,383,548	236,891	816	29,103	4,770	2	2,655,130
2025	2,409,252	237,000	825	29,239	4,802	2	2,681,120
2026	2,435,943	236,529	724	29,398	4,923	2	2,707,518
2027	2,462,224	235,996	718	29,505	5,028	2	2,733,473
2028	2,488,000	235,423	712	29,582	5,132	2	2,758,852
2029	2,513,233	234,807	706	29,617	5,237	2	2,783,603
2030	2,538,194	234,169	700	29,634	5,341	2	2,808,041
2031	2,563,113	233,527	694	29,697	5,446	2	2,832,479
2032	2,588,042	232,886	688	29,776	5,551	2	2,856,945
2033	2,613,094	232,255	682	29,853	5,655	2	2,881,541
2034	2,638,402	231,644	676	29,925	5,760	2	2,906,408
2035	2,663,983	231,054	670	29,988	5,864	2	2,931,561
2036	2,689,831	230,486	664	30,040	5,969	2	2,956,992
2037	2,715,961	229,940	658	30,086	6,073	2	2,982,720
2038	2,742,315	229,412	652	30,128	6,178	2	3,008,687
2039	2,768,788	228,894	646	30,170	6,282	2	3,034,782
2040	2,795,313	228,381	640	30,212	6,387	2	3,060,934
2041	2,821,906	227,872	634	30,254	6,491	2	3,087,159
2042	2,848,593	227,371	628	30,295	6,596	2	3,113,485
2043	2,875,364	226,877	622	30,335	6,701	2	3,139,900
2044	2,902,187	226,386	616	30,371	6,805	2	3,166,367
2045	2,929,019	225,897	610	30,404	6,910	2	3,192,841

Note: Historic (2015 - 2024); Projected (2025 - 2045, Jan - Jun actuals used for 2025)
Appendix 2B-5 has been provided with the 2025 Company Load Forecast instead of the 2025 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 2B-6: North Carolina Customer Count

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2015	101,620	15,677	52	1,853	384	1	119,586
2016	102,079	15,775	51	1,846	381	1	120,133
2017	102,429	15,821	52	1,857	381	1	120,541
2018	102,865	15,944	50	1,844	381	1	121,085
2019	103,458	16,055	50	1,838	375	1	121,777
2020	105,087	16,083	50	1,982	373	1	123,576
2021	106,011	16,288	48	2,009	368	1	124,725
2022	106,928	16,404	47	2,005	372	1	125,757
2023	108,262	16,288	54	2,591	379	1	127,575
2024	108,656	16,236	59	2,629	548	1	128,129
2025	109,373	16,247	70	2,641	521	1	128,852
2026	110,481	16,264	71	2,673	539	1	130,028
2027	111,481	16,247	71	2,709	578	1	131,087
2028	112,461	16,230	71	2,734	618	1	132,114
2029	113,421	16,211	71	2,746	657	1	133,106
2030	114,370	16,191	71	2,752	697	1	134,081
2031	115,318	16,171	71	2,772	736	1	135,069
2032	116,267	16,151	71	2,799	775	1	136,063
2033	117,219	16,131	71	2,824	815	1	137,062
2034	118,182	16,112	71	2,848	854	1	138,069
2035	119,155	16,094	71	2,869	894	1	139,084
2036	120,139	16,076	71	2,886	933	1	140,107
2037	121,132	16,059	71	2,902	973	1	141,138
2038	122,135	16,043	71	2,916	1,012	1	142,178
2039	123,142	16,027	71	2,930	1,052	1	143,222
2040	124,151	16,011	71	2,944	1,091	1	144,269
2041	125,163	15,995	71	2,958	1,131	1	145,318
2042	126,178	15,980	71	2,971	1,170	1	146,371
2043	127,196	15,964	71	2,984	1,209	1	147,426
2044	128,216	15,949	71	2,996	1,249	1	148,483
2045	129,237	15,934	71	3,007	1,288	1	149,539

Note: Historic (2015 - 2024); Projected (2025 - 2045, Jan - Jun actuals used for 2025)
Appendix 2B-6 has been provided with the 2025 Company Load Forecast instead of the 2025 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 2B-7: DOM LSE Summer and Winter Peak Demand (MW)

Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)
2015	16,502	18,434
2016	16,914	16,173
2017	16,350	16,618
2018	16,528	17,792
2019	16,599	16,842
2020	16,356	14,661
2021	16,462	14,469
2022	17,131	17,813
2023	17,775	15,643
2024	18,023	17,740
2025	18,303	17,688
2026	18,470	17,644
2027	18,707	17,780
2028	19,232	18,142
2029	19,370	18,927
2030	19,898	19,357
2031	20,471	19,728
2032	21,133	20,134
2033	21,710	20,848
2034	22,467	21,451
2035	22,930	22,224
2036	23,643	22,694
2037	24,370	23,034
2038	24,910	23,888
2039	25,421	24,371
2040	25,953	24,773
2041	26,570	25,203
2042	27,152	25,620
2043	27,823	26,037
2044	28,237	27,003
2045	28,963	27,470

Note: Historic (2015 - 2024); Projected (2025 - 2045, Jan - Jun actuals used for 2025)
Appendix 2B-7 has been provided with the 2025 Company Load Forecast instead of the 2025 PJM Load Forecast because PJ
because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 2B-8 - Projected Summer & Winter Peak Load & Energy Forecast

Company Name: Virginia Electric and Power Company **Schedule 1**

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)[1]			(PROJECTED)														
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
1. Utility Peak Load (MW)																		
A. Summer																		
1. Base Forecast (LSE Equivalent)	17,299	17,983	18,680	18,996	19,404	19,936	20,727	20,952	21,549	22,147	22,810	23,400	24,136	24,614	25,331	26,078	26,646	27,218
2. Energy Efficiency & Demand Response(2)(3)(6)	(168)	(208)	(271)	(153)	(394)	(689)	(956)	(1,042)	(1,111)	(1,136)	(1,137)	(1,149)	(1,129)	(1,144)	(1,148)	(1,167)	(1,196)	(1,257)
3. Customer Choice (non data center)(5)	-	-	-	(540)	(540)	(540)	(540)	(540)	(540)	(540)	(540)	(540)	(540)	(540)	(540)	(540)	(540)	(540)
4. Summer Adjusted Load	17,131	17,775	18,409	18,303	18,470	18,707	19,231	19,370	19,898	20,471	21,133	21,711	22,467	22,930	23,643	24,371	24,910	25,421
5. % Increase in Adjusted Load (from previous year)		4%	4%	-1%	1%	1%	3%	1%	3%	3%	3%	3%	3%	2%	3%	3%	2%	2%
B. Winter																		
1. Base Forecast (LSE Equivalent)	17,989	15,848	17,728	18,155	18,285	18,650	19,226	20,062	20,530	20,944	21,363	22,095	22,718	23,512	24,008	24,387	25,258	25,785
2. Energy Efficiency & Demand Response(2)(3)(6)	(176)	(204)	(249)	(16)	(185)	(414)	(627)	(679)	(716)	(760)	(773)	(791)	(811)	(831)	(857)	(897)	(914)	(958)
3. Customer Choice (non data center)(5)	-	-	-	(451)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)	(456)
4. Winter Adjusted Load	17,813	15,643	17,479	17,688	17,644	17,780	18,143	18,927	19,358	19,728	20,134	20,848	21,451	22,225	22,695	23,034	23,888	24,371
5. % Increase in Adjusted Load (from previous year)		-12%	12%	1%	0%	1%	2%	4%	2%	2%	2%	4%	3%	4%	2%	1%	4%	2%
2. Energy (GWh)																		
A. Base Forecast (LSE Equivalent)	92,034	92,652	96,889	106,049	107,238	110,920	115,223	119,430	124,155	129,106	134,424	139,633	145,077	150,757	156,918	162,555	168,077	172,406
B. Winter Additional Forecast Future BTM(4)	-	-	-	(1,517)	(1,525)	(1,539)	(1,619)	(1,677)	(1,807)	(1,948)	(2,097)	(2,247)	(2,482)	(2,719)	(2,956)	(3,189)	(3,236)	(3,220)
C. Energy Efficiency & Demand Response(2)(3)(6)	(854)	(997)	(1,154)	(302)	(1,102)	(1,936)	(2,769)	(2,868)	(2,931)	(2,990)	(3,037)	(3,079)	(3,149)	(3,193)	(3,238)	(3,311)	(3,394)	(3,512)
D. Customer Choice (non data center)(5)	-	-	-	(3,109)	(3,119)	(3,119)	(3,128)	(3,119)	(3,119)	(3,119)	(3,128)	(3,119)	(3,119)	(3,119)	(3,128)	(3,119)	(3,119)	(3,119)
E. Adjusted Energy	91,180	91,655	95,735	101,121	101,492	104,326	107,707	111,766	116,298	121,049	126,162	131,188	136,327	141,726	147,596	152,936	158,328	162,555
F. % Increase in Adjusted Energy		1%	4%	6%	0%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%

(1) Actual metered data

(2) Demand response programs are not classified as capacity resources and are included in adjusted load.

(3) 2023-2024 actual historical data based upon measured and verified EM&V results

(4) Future behind-the-meter, which is not included in the base forecast.

Appendix 2B-9 - Required Reserve Margin

Company Name: Virginia Electric and Power Company

Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)														
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
I. Reserve Margin																		
1. Summer Reserve Margin																		
a. MW(1)	2,006	1,518	(815)	693	-	-	-	-	-	-	-	-	-	-	-	-	-	-
b. Percent of Load	11.6%	8.4%	-4.4%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
c. Actual Reserve Margin(2)	N/A	N/A	N/A	-5.8%	-9.2%	-10.4%	-10.0%	-8.7%	-9.3%	-12.7%	-12.1%	-7.9%	-2.6%	-2.6%	-2.2%	0.0%	2.4%	3.0%
2. Winter Reserve Margin																		
a. MW(1)	N/A	N/A	N/A	1,308	(103)	(9)	134	228	266	424	323	287	298	329	329	359	375	378
b. Percent of Load	N/A	N/A	N/A	7.4%	-0.6%	-0.1%	0.7%	1.2%	1.4%	2.2%	1.6%	1.4%	1.4%	1.5%	1.5%	1.6%	1.6%	1.6%
c. Actual Reserve Margin(2)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
II. Annual Loss-of-Load Hours(3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) Beginning in 2026 reserve margin MWs are imbeded in the PJM FPR adjusted annual capacity target.

(2) Does not include spot purchases of capacity or energy efficiency programs.

(3) The Company follows PJM reserve requirements which are based on loss of load expectation.

Appendix 2B-10 – Summer and Winter Peak

Company Name: Virginia Electric and Power Company

Schedule 5

POWER SUPPLY DATA

	(ACTUAL)			(PROJECTED)															
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak(1)	17,131	17,775	18,409	18,303	18,470	18,707	19,231	19,370	19,898	20,471	21,133	21,711	22,467	22,930	23,643	24,371	24,910	25,421	25,952
b. Other Commitments(2)	168	208	271	693	934	1,229	1,496	1,582	1,651	1,676	1,677	1,689	1,669	1,684	1,688	1,707	1,736	1,797	1,824
c. Total System Summer Peak	17,299	17,983	18,680	18,996	19,404	19,936	20,727	20,952	21,549	22,147	22,810	23,400	24,136	24,614	25,331	26,078	26,646	27,218	27,776
d. Percent Increase in Total Summer Peak	0.6%	4.0%	3.9%	1.7%	2.1%	2.7%	4.0%	1.1%	2.8%	2.8%	3.0%	2.6%	3.1%	2.0%	2.9%	2.9%	2.2%	2.1%	2.1%
2. Winter																			
a. Adjusted Winter Peak(1)	17,813	15,643	17,479	17,688	17,644	17,780	18,143	18,927	19,358	19,728	20,134	20,848	21,451	22,225	22,695	23,034	23,888	24,371	24,773
b. Other Commitments(2)	176	204	249	467	641	870	1,083	1,135	1,172	1,216	1,229	1,247	1,267	1,287	1,313	1,353	1,370	1,414	1,407
c. Total System Winter Peak	17,989	15,848	17,728	18,155	18,285	18,650	19,226	20,062	20,530	20,944	21,363	22,095	22,718	23,512	24,008	24,387	25,258	25,785	26,180
d. Percent Increase in Total Winter Peak	-1.3%	-11.9%	11.9%	2.4%	0.7%	2.0%	3.1%	4.3%	2.3%	2.0%	2.0%	3.4%	2.8%	3.5%	2.1%	1.6%	3.6%	2.1%	1.5%

(1) Adjusted load from Appendix 2B-8.

(2) Includes energy efficiency, demand side management, and customer choice from Appendix 2B-8.

Appendix 2B-11 – Wholesale Power Sales Contracts

Company Name: Virginia Electric and Power Company **Schedule 20**

WHOLESALE POWER SALES CONTRACTS

			(Actual MWs)[2]			
Entity	**Contract Length**	**Contract Type**	**2021**	**2022**	**2023**	**2024**
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements[1]	10	13	9	17
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements[1]	10	11	10	10
Virginia Municipal Electric Association	5/31/2031 with potential for renewal	Full Requirements[1]	291	286	284	297

(1) Full requirements contracts do not have a specific contracted capacity amount. MWs are included in the Company's load forecast.

(2) Actual customer peak load measures are included.

Appendix 2C-1 – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Line #2242 Uprate - Dulles to Lincoln Park	230	Aug-25	VA	11.8
Line #2188 Uprate-Shellhorn to Greenway to Lockridge	230	Aug-25	VA	4.5
Line #293 (Staunton to Valley) & Partial Line #83 EOL	230	Aug-25	VA	44.8
Line #2021 Shawboro to Elizabeth City EOL Rebuild	230	Aug-25	NC	33.5
Metcalf - Upgrade TX #1 - DEV	115	Sep-25	VA	1.8
Roundtable 230kV Delivery - Add 3rd and 4th TX	230	Sep-25	VA	1.0
Interconnection 230kV Delivery - DEV	230	Sep-25	VA	32.0
Pearsons 230kV Switch Replacements EOL	230	Oct-25	VA	0.5
New Post 230 kV Delivery - REC	230	Oct-25	VA	18.8
EPG - Add 2nd and 3rd TX - DEV	230	Nov-25	VA	1.5
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild	115	Nov-25	NC	27.1
Install 2nd 115kV 33.67MVar Cap bank at Harrisonburg	115	Dec-25	VA	1.0
Trident sub 230kV Delivery - NOVEC	230	Dec-25	VA	27.8
Allen Creek Sub - Timber-2 DP - 230kV Delivery - MEC	230	Dec-25	VA	30.0
230kV Line Extension to Relieve Cloverhill Loop (Winters Branch - Wakeman)	230	Dec-25	VA	3.9
Buttermilk 230kV Delivery - Add 3rd and 4th TX	230	Dec-25	VA	1.0
Brickyard 230kV Delivery - DEV	230	Dec-25	VA	6.6
Lee's Hill 230 kV Delivery - ODEC	230	Dec-25	VA	15.5
Line #183 (Bristers to Ox) Rebuild EOL	115	Dec-25	VA	30.0
500kV / 230kV Line Extension - Southern (Wishing Star to Mars)	230/500	Dec-25	VA	842.3
Line #172 & # 197 Conversion - Liberty to Cannon Branch	230	Dec-25	VA	28.0
Foster Drive 230 kV Delivery - CoM (BCG & AWS)	230	Dec-25	VA	15.3
Line #77 (Carolina-Roanoke Rapids Hydro) EOL Rebuild	115	Dec-25	NC	7.4
230kV Line Extension to Relieve Waxpool Loop (Nimbus to Farmwell)	230	Dec-25	VA	5.7
Line #2011 Uprate - Cannon Branch to Clifton (Rebuild)	230	Dec-25	VA	31.7
Line #224 (Lanexa -Northern Neck) EOL Rebuild and 2nd Circuit	230	Dec-25	VA	151.0
Princess Anne Sub - Upgrade TX#1 - DEV	115	Dec-25	VA	0.5

Appendix 2C-1 – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Verona Substation - Replace TX#2 - DEV	115	Dec-25	VA	0.5
Landstown TX#1 EOL Replacement	115/230	Dec-25	VA	6.5
Line #53 (Chesterfield - Kevlar) Install Reymet Tap	115	Jan-26	VA	3.0
Harrisonburg TX#6 EOL	69/230	Jan-26	VA	6.8
Line #2209 Uprate Evergreen Mills to Yardley	230	Jan-26	VA	5.0
Line #53 and Line #72 (Chesterfield to Brown Boveri Tap) EOL Partial Rebuild	115	Jan-26	VA	9.8
Decoy Airfield Sub - New 230kV Delivery - DEV	230	Feb-26	VA	12.0
Southall 230kV Delivery - REC	230	Feb-26	VA	28.0
Navy N - New 50 MVAR Capbank (DNH)	230	Mar-26	VA	3.0
Ruther Glen Sub New 230kV Delivery - REC	230	Mar-26	VA	45.0
Pleasant View 230kV Delivery - Add 4th TX - DEV	230	Mar-26	VA	1.0
Line #2031 Uprate-Enterprise to Greenway to Roundtable	230	Mar-26	VA	5.9
Line #2223 Uprate-Roundtable to Lockridge	230	Mar-26	VA	2.6
Line #2214 Uprate - Buttermilk to Roundtable	230	Mar-26	VA	4.8
Butler Farm Sub - 230kV Delivery-DEV- Bailey DP - New Finneywood 500/230kV Sub a new 230kV Line (Butler Farm - Finneywood) and a new 230kV Line (Butler Farm - Clover)	230/500	Mar-26	VA	220.0
Prentice Drive 230kV Delivery - DEV	230	Mar-26	VA	20.0
Northwoods 230kV Delivery - NOVEC	230	Apr-26	VA	20.0
Evans Creek Sub – Roanoke DP - 230kV Delivery-DEV_New 230kV Line from Tunstall to Evans Creek and Evans Creek to Raines	230	Apr-26	VA	30.0
Tunstall Sub – Hillcrest DP - 230kV Delivery-DEV-New Unity 500/230kV Sub - Two New 230kV Lines from Unity to Tunstall	230/500	Apr-26	VA	140.0
Raines Sub - Interstate DP - 230kV Delivery-DEV-New 230kV Line from Tunstall to Raines	230	Apr-26	VA	20.0
PRETLOW - New 115kV Delivery - C. of Franklin	115	Apr-26	VA	2.5
Walnut Creek 115kV switching station	115	May-26	VA	23.7

Appendix 2C-1 – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Line #574 - Ladysmith to Elmont Rebuild - EOL	500	May-26	VA	91.3
Partial Line #26 (Buena Vista to Balcony Falls) Rebuild	115	Jun-26	VA	22.2
Relieve Line 219-2066 Load Drop - Loop Trabue 230kV to Midlothian	230	Jun-26	VA	8.5
Ladysmith CT - Replace Overdutied 230kV Breakers	230	Jun-26	VA	1.6
Lost City Sub - Add TX#5 - DEV	230	Jun-26	VA	0.6
Lines #211 and #228 (Chesterfield to Hopewell) partial rebuild	230	Jun-26	VA	12.3
Line #1024 (Chestnut - S Justice Branch) EOL Rebuild	115	Jun-26	NC	5.1
Cloud 115kV Cap Bank	115	Jun-26	VA	1.5
Line #2151 Uprate - Railroad DP to Gainesville	230	Jun-26	VA	6.1
Line #2226 (Clover to Easters) Partial Rebuild (DNH)	230	Jun-26	VA	34.0
Nimbus 230kV Delivery - DEV	230	Jun-26	VA	12.0
Line #550 (Mount Storm to Valley) Rebuild	500	Jun-26	VA	256.0
Line #2172 Uprate - Brambleton to Evergreen	230	Jul-26	VA	2.3
Line #2210 Uprate - Brambleton to Evergreen Mills	230	Jul-26	VA	2.3
Line #2213 Uprate - Yardley to Cabin Run	230	Jul-26	VA	1.8
Stratus 230kV Delivery - DEV	230	Jul-26	VA	24.0
Daves Store 230 kV Line Extension (New) (Cut and Extend Line #2161 Gainesville - Wheeler)	230	Aug-26	VA	45.9
Park Center 230kV Delivery - DEV	230	Aug-26	VA	10.0
Daves Store 230kV Delivery - DEV	230	Aug-26	VA	36.5
Trabue Sub - Upgrade TX#1 - DEV	230	Aug-26	VA	11.0
Spartan - 230 kV Delivery - DEV	230	Sep-26	VA	15.4
Line #2104 (Cranes Corner to Stafford) partial uprate	230	Sep-26	VA	28.9
Ocean Court 230kV Delivery - DEV	230	Oct-26	VA	12.7
Install Cap Bank at Lexington substation	500	Nov-26	VA	5.9
Line #260 (Harrisonburg to Grottoes) EOL Rebuild	230	Nov-26	VA	28.0
Bring 2-230 kV Sources into White Oak SUB and Resolve 300 MW Load Loss Violation	230	Nov-26	VA	42.2

Appendix 2C-1 – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Davis Drive - 230kV Ring Bus Expansion - Line Extension W&OD Trail to Sub	230	Nov-26	VA	15.0
Possum Point 2nd 500-230kV TX (Ox Overloads) (PP 500kV - PP230kV)	230/500	Nov-26	VA	23.1
Sycolin Creek Substation - DEV	230	Nov-26	VA	20.0
Reed Farm (South Fork) 230kV Delivery - NOVEC	230	Nov-26	VA	17.1
Wishing Star DP -NOVEC	230	Dec-26	VA	1.5
Line #205 (Locks to Tyler) Partial Rebuild	230	Dec-26	VA	19.0
Line #2080 Uprate - Liberty to Railroad DP	230	Dec-26	VA	1.5
Line #2163 Uprate - Vint Hill to Liberty	230	Dec-26	VA	13.0
Line #2187 and #2228 Uprate - Pioneer DP to Liberty	230	Dec-26	VA	5.7
Clifton - Replace Overdutied L282 Breaker	230	Dec-26	VA	0.5
Idylwood - Convert Straight Bus to Breaker and a Half	230	Dec-26	VA	159.4
Alexanders Corner Tx 1 Replace Ground Switch with Circuit Switcher	115	Dec-26	VA	0.3
Brown Boveri Tx 1 Replace Ground Switch with Circuit Switcher	115	Dec-26	VA	0.3
Deep Creek Tx 1 Replace Ground Switch with Circuit Switcher	115	Dec-26	VA	0.3
Deep Creek Tx 2 Replace Ground Switch with Circuit Switcher	115	Dec-26	VA	0.3
Line #108 (Boykins-Tunis) EOL Rebuild	115	Dec-26	NC	72.7
Line #126 (Earleys to Kelford) Partial Rebuild	115	Dec-26	NC	18.8
Line #2056 (Hornertown-Hathaway) EOL Rebuild	230	Dec-26	NC	49.1
Line #29 Fredericksburg to Aquia Harbor rebuild	230	Dec-26	VA	59.5
Line #502 Terminal Upgrade-Loudoun to Mosby	500	Dec-26	VA	6.3
Line #584 Terminal Upgrade-Loudoun to Mosby	500	Dec-26	VA	6.4
Quantico Tx 1 Replace Ground Switch with Circuit Switcher	115	Dec-26	VA	0.3
Quantico Tx 2 Replace Ground Switch with Circuit Switcher	115	Dec-26	VA	0.3
Tunis Tx 1 Replace Ground Switch with Circuit Switcher	115	Dec-26	VA	0.3
Bermuda Hundred Sub - New 230kV Delivery - DEV	230	Dec-26	VA	15.0
Gainesville 230 kV Terminal Upgrades (Line #2222)	230	Dec-26	VA	10.0

Appendix 2C-1 – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Landstown TX#2 EOL Replacement	115/230	Dec-26	VA	4.5
Line #588 Yadkin-Fentress EOL Rebuild	500	Dec-26	VA	91.4
Remington CT 230 kV Terminal Upgrades (Line #2114)	230	Dec-26	VA	2.7
Line # 2090 (Ladysmith CT to Summit) Rebuild	230	Jan-27	VA	32.0
Line #1001 (Battleboro to Chestnut) EOL Rebuild	115	Jan-27	NC	14.0
Jeffress Substation 230 kV Delivery (MEC)	230	Jan-27	VA	142.8
Germanna 230kV Delivery - DEV	230	Jan-27	VA	24.8
Line #23 Bell Ave to Suffolk Partial Reconductor	115	Feb-27	VA	39.5
Line #2010 Underground Relocation	230	Mar-27	VA	40.0
Brambleton Overdutied Breaker Replacement (SC102,H302, H402, 218302)	230	Mar-27	VA	5.6
Broderick Drive 230kV Delivery - DEV	230	Mar-27	VA	32.0
Gemini 230 kV Delivery - DEV	230	Mar-27	VA	15.3
Bear Run Expansion (Cub Run) Substation	230	Mar-27	VA	34.5
Tributary 230 kV Delivery - REC (FMR LC Riedhill River View)	230	Apr-27	VA	33.2
Carmel Church Sub - New 230 kV Delivery - REC	230	Apr-27	VA	36.5
Meadowville Sub - New 230kV Delivery - DEV	230	Apr-27	VA	17.2
Mars 2nd 500 -230 kV TX	230/500	May-27	VA	42.2
Bristers - 500-230 kV TX Expansion	230/500	May-27	VA	65.0
Evergreen Mills 230kV Delivery Part B	230	Jun-27	VA	7.7
Line #2207 Uprate- Paragon Park to Beco	230	Jun-27	VA	5.3
Lines #2150 & #2081 Uprates-Golden to Paragon Park	230	Jun-27	VA	6.3
Lines #2150 & #2081 Uprates-Golden to Sterling Park	230	Jun-27	VA	8.0
New Nextera 500 kV Line from Woodside to Goose Creek Sub (DOM Scope)	500	Jun-27	VA	15.6
Terminate New Nextera 500kV Line from Woodside into Goose Creek Sub DOM	500	Jun-27	VA	30.5
Youngs Branch - Add 3rd, 4th, 5th TX - DEV (Position #1,3,5)	230	Jun-27	VA	3.0

Appendix 2C-1 – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Pluto 230 kV Delivery - DEV	230	Jun-27	VA	64.5
Line #256 (Ladysmith - St John) Partial Rebuild	230	Jun-27	VA	31.7
Loudoun Capacitor Banks	230/500	Jun-27	VA	109.0
Line #14 (Fudge Hollow to the demarcation point of AEP) EOL	115	Jun-27	VA	30.0
Line #9290 (Ox to Braddock) and Partial Line#2097 Uprate	230	Jun-27	VA	43.5
Line #265 Uprate - Sully to Takeoff	230	Aug-27	VA	4.6
Takeoff Substation 230kV Interconnection for Poland Loop	230	Aug-27	VA	45.9
Takeoff 230kV Delivery - DEV Transformers	230	Aug-27	VA	4.2
Line #272 (Dooms to Grottoes) EOL Rebuild	230	Aug-27	VA	34.0
Foxbrook Lane 230kV Delivery - REC (AWS Central Louisa - 1st DP)	230	Sep-27	VA	29.2
Centreport New 230kV Switching Station - DEV	230	Sep-27	VA	42.3
Edsall 230kV Delivery - DEV	230	Oct-27	VA	23.0
Devlin sub 230kV Delivery - NOVEC	230	Oct-27	VA	74.0
Bunker Sub - New 230kV Delivery - DEV	230	Oct-27	VA	9.5
Pegasus Sub 230kV Delivery - NOVEC	230	Nov-27	VA	28.5
Cirrus New 230kV DP - REC and Partial conversion of lines #2 and #70 to 230kV	230	Nov-27	VA	77.3
Avanti sub 230kV Delivery - NOVEC	230	Nov-27	VA	45.0
Ironbridge Sub - Upgrade TX#2 - DEV	230	Nov-27	VA	10.3
Towerview 230kV Delivery - DEV	230	Nov-27	VA	50.0
5-2 North Line Extension - Aspen to Golden	230/500	Dec-27	VA	623.0
Locks Substation 230/115 kV Transformer Upgrade	115/230	Dec-27	VA	7.1
Line #2101 Uprate - Bristers to Vint Hill	230	Dec-27	VA	23.0
Line #58 (Skiffes to Yorktown) EOL Partial Rebuild	115	Dec-27	VA	19.5
Sloan Drive Sub - New 230kV Delivery - DEV	230	Dec-27	VA	30.0
Saltwood Sub - New 230kV Delivery - DEV	230	Feb-28	VA	15.8
Partial Line #83 (Craigsville-Staunton) EOL Rebuild	115	Mar-28	VA	23.0
Enon Substation - Add New TX #3	230	Mar-28	VA	24.0

Appendix 2C-1 – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Atlas 230 kV Delivery - DEV	230	Apr-28	VA	15.4
White Mountain Sub - New 230kV Delivery DEV	230	Apr-28	VA	19.2
Convert Line #2 (Remington and Oak Green)to 230kV (DNH)	115/230	May-28	VA	50.0
Palomino 230kV Delivery - DEV	230	May-28	VA	50.0
Mt. Pony 230kV Delivery – DEV	230	May-28	VA	75.0
Chandler 230kV Delivery – DEV	230	May-28	VA	75.0
McDevitt 230kV Delivery - DEV	230	May-28	VA	75.0
Old Limb 230kV Delivery - DEV	230	May-28	VA	40.7
Varina Substation - Add 2nd TX - DEV	230	May-28	VA	1.0
Twin Creeks Sub 230kV Delivery - DEV	230	May-28	VA	56.0
5-2 Connecter - Mars to Golden	230/500	Jun-28	VA	342.9
Line #557 (Chickahominy to Elmont) EOL Rebuild	500	Jun-28	VA	58.2
Lines #2194 & #9231 Uprates-Davis Drive to Sterling Park	230	Jun-28	VA	5.5
Morrisville to Anderson Branch 230 kV Line	230	Jun-28	VA	7.2
Otterdale Sub - New 230kV Delivery - DEV	230	Jun-28	VA	139.0
Barrister Sub 230kV Delivery - DEV	230	Jun-28	VA	24.0
Line # 2135 (HollyMeade to Gordonsville) Rebuild	230	Jun-28	VA	36.0
Cloverhill 230 kV Delivery - Add 4th and 5th TX - DEV	230	Jul-28	VA	1.3
230kV Line Extension to Relieve Poland Loop (Aviator to Takeoff)	230	Aug-28	VA	28.0
Nimbus 230kV Delivery - Add 3rd and 4th TX	230	Oct-28	VA	1.4
Nebula to Raines - New 230kV Line	230	Nov-28	VA	93.7
Nebula New 230kV Switching Station - Visor DP - MEC	230	Nov-28	VA	35.8
Line #204 and #220 Partial Rebuild EOL	230	Nov-28	VA	6.1
Line #202 - Clark to Idylwood Uprate	230	Dec-28	VA	8.0
Line #579 Septa-Yadkin EOL Rebuild and Line #2110 Partial Rebuild	500	Dec-28	VA	257.0
Line # 2054 (Charlottesville to Hollymead) Rebuild	230	Dec-28	VA	70.5
Line #246 Earleys to Suffolk EOL Rebuild	230	Dec-28	VA-NC	150.0
Weyers Cave - Add 2nd TX - DEV	230	Dec-28	VA	0.9

Appendix 2C-1 – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Line #136 (Tunis to Earleys) EOL Rebuild	115	Dec-28	NC	55.2
Line #209 and #58 (Skiffes to Yorktown) EOL Partial Rebuild	230	Dec-28	VA	13.5
Line #92 (Chesterfield to Lanexa) /#287 (Chesterfield to Chickahominy) /#2129 (Chickahominy to Lanexa) EOL Rebuild	115/230	Dec-28	VA	161.5
Third 230kV Source to Project Peanut	230	Dec-28	VA	25.9
Line #10 (Goshen to Craigsville) EOL Partial Rebuild	115	Mar-29	VA	29.6
Fentress Substation - Add New TX #2	230	May-29	VA	0.4
Devlin to Pegasus 230 kV Line Extension	230	Jun-29	VA	42.4
Joshua Falls - Yeat New 765kV Line and Yeat 765/500/230kV Substation	230/500/765	Jun-29	VA	1,015.7
Line 119 (Merck to Port Republic) Uprate	115	Jun-29	VA	42.3
Line #2003 (Poe to Tyler) Uprate	230	Jun-29	VA	32.3
Line #2161 Uprate - Gainesville to Wheeler	230	Jun-29	VA	33.0
Line #299 Rebuild - Remington CT to Marsh Run	230	Jun-29	VA	14.3
Loudoun 500 kV Terminal Upgrades (Line 535 and 569)	500	Jun-29	VA	6.4
Ladysmith Substation Expansion	230/500	Jun-29	VA	19.0
New 230kV Line Elmont - Ladysmith (Line #574 underbuild)	230	Jun-29	VA	28.3
New 230kV Line - Nokesville to Hornbaker 2nd Circuit	230	Jun-29	VA	18.0
New 230 kV Source into Cloverhill (Nokesville)	230	Jun-29	VA	296.2
Replace Overdutied Breakers - 2024 Reliability Open Window #1	230/500	Jun-29	VA	89.3
Uprate Goose Creek 500-230kV TX	230/500	Jun-29	VA	34.0
Vint Hill to Devlin 2nd 230 kV Line	230	Jun-29	VA	24.0
Vint Hill 500-230 kV Expansion	230/500	Jun-29	VA	307.0
Line 1031 (Terra to Pantego) Line Rebuild	115	Jun-29	NC	29.4
Line #121 (Poe to Prince George) Conversion	115/230	Jun-29	VA	79.5
Line 2002 (Carson to Poe) Uprate	230	Jun-29	VA	32.3
Line #213 and #225 Rebuild - Thelma to Lakeview	230	Jun-29	NC	48.7
Nokesville to Hornbaker 230 kV Line	230	Jul-29	VA	139.0

Appendix 2C-1 – List of Transmission Projects Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Lunar 230kV Delivery - DEV	230	Jul-29	VA	51.6
Spring Hill 230kV Delivery - DEV	230	Oct-29	VA	35.0
Apollo 230kV Delivery - DEV	230	Oct-29	VA	54.6
Elmont Substation 500kV Terminal Upgrades	500	Nov-29	VA	8.9
Lines #233 and 291 (Dooms to Charlottesville) Rebuild	230	Dec-29	VA	112.0
Bristow Sub 230kV Delivery - NOVEC	230	Dec-29	VA	17.0
Convert Line #29 Fredericksburg to Possum Point to 230 kV	230	Dec-29	VA	91.0
Add 3rd and 4th 230kV Lines from Aquia Harbour to Possum Point	230	Dec-29	VA	93.9
Line #29 and #252 (Possum Point to Aquia Harbor) Rebuild	115/230	Dec-29	VA	117.3
500/230kV Morrisville-Wishing Star New 500kV Line	230/500	Jun-30	VA	863.2
500 kV line extension - Aspen to Doubs	230/500	Sep-30	VA	74.1
Terminate Line 583 Doubs - Bismark into Woodside 500kV DOM	500	Sep-30	VA	5.1
Kraken New 500-230 Switching Station	230/500	Sep-30	VA	91.7
New 500kV Line - North Anna - Kraken - Yeat	500	Sep-30	VA	590.5
Starlight Substation - DEV	230	Oct-30	VA	28.0
Occoquan 500-230kV TX (OX violation); Line 2013 Upgrade and Cut in of Line #571 and #237	230/500	Dec-30	VA	76.5
Replace Overdutied Breakers _ 2022 Reliability Open Window #3	230/500	Dec-31	VA	66.8
Gray Bark Sub - New 230kV Delivery - DEV	230	Dec-33	VA	40.0
Thicket Sub - New 230kV Delivery - DEV	230	Dec-33	VA	25.0

Appendix 2C-2 - List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Line #2242 Uprate - Dulles to Lincoln Park	230	Aug-25	VA	11.8
Line #2188 Uprate-Shellhorn to Greenway to Lockridge	230	Aug-25	VA	4.5
Line #293 (Staunton to Valley) & Partial Line #83 EOL	230	Aug-25	VA	44.8
Line #2021 Shawboro to Elizabeth City EOL Rebuild	230	Aug-25	NC	33.5
Metcalf - Upgrade TX #1 - DEV	115	Sep-25	VA	1.8
Roundtable 230kV Delivery - Add 3rd and 4th TX	230	Sep-25	VA	1.0
Interconnection 230kV Delivery - DEV	230	Sep-25	VA	32.0
Pearsons 230kV Switch Replacements EOL	230	Oct-25	VA	0.5
New Post 230 kV Delivery - REC	230	Oct-25	VA	18.8
EPG - Add 2nd and 3rd TX - DEV	230	Nov-25	VA	1.5
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild	115	Nov-25	NC	27.1
Install 2nd 115kV 33.67MVar Cap bank at Harrisonburg	115	Dec-25	VA	1.0
Trident sub 230kV Delivery - NOVEC	230	Dec-25	VA	27.8
Allen Creek Sub - Timber-2 DP - 230kV Delivery - MEC	230	Dec-25	VA	30.0
230kV Line Extension to Relieve Cloverhill Loop (Winters Branch - Wakeman)	230	Dec-25	VA	3.9
Buttermilk 230kV Delivery - Add 3rd and 4th TX	230	Dec-25	VA	1.0
Brickyard 230kV Delivery - DEV	230	Dec-25	VA	6.6
Lee's Hill 230 kV Delivery - ODEC	230	Dec-25	VA	15.5
Line #183 (Bristers to Ox) Rebuild EOL	115	Dec-25	VA	30.0
500kV / 230kV Line Extension - Southern (Wishing Star to Mars)	230/500	Dec-25	VA	842.3
Line #172 & # 197 Conversion - Liberty to Cannon Branch	230	Dec-25	VA	28.0
Foster Drive 230 kV Delivery - CoM (BCG & AWS)	230	Dec-25	VA	15.3
Line #77 (Carolina-Roanoke Rapids Hydro) EOL Rebuild	115	Dec-25	NC	7.4
230kV Line Extension to Relieve Waxpool Loop (Nimbus to Farmwell)	230	Dec-25	VA	5.7
Line #2011 Uprate - Cannon Branch to Clifton (Rebuild)	230	Dec-25	VA	31.7
Line #224 (Lanexa -Northern Neck) EOL Rebuild and 2nd Circuit	230	Dec-25	VA	151.0
Princess Anne Sub - Upgrade TX#1 - DEV	115	Dec-25	VA	0.5

Appendix 2C-2 - List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Verona Substation - Replace TX#2 - DEV	115	Dec-25	VA	0.5
Line #53 (Chesterfield - Kevlar) Install Reymet Tap	115	Jan-26	VA	3.0
Line #53 and Line #72 (Chesterfield to Brown Boveri Tap) EOL Partial Rebuild	115	Jan-26	VA	9.8
Decoy Airfield Sub - New 230kV Delivery - DEV	230	Feb-26	VA	12.0
Southall 230kV Delivery - REC	230	Feb-26	VA	28.0
Pleasant View 230kV Delivery - Add 4th TX - DEV	230	Mar-26	VA	1.0
Line #2031 Uprate-Enterprise to Greenway to Roundtable	230	Mar-26	VA	5.9
Line #2223 Uprate-Roundtable to Lockridge	230	Mar-26	VA	2.6
Line #2214 Uprate - Buttermilk to Roundtable	230	Mar-26	VA	4.8
Prentice Drive 230kV Delivery - DEV	230	Mar-26	VA	20.0
Evans Creek Sub – Roanoke DP - 230kV Delivery-DEV_New 230kV Line from Tunstall to Evans Creek and Evans Creek to Raines	230	Apr-26	VA	30.0
Tunstall Sub – Hillcrest DP - 230kV Delivery-DEV-New Unity 500/230kV Sub - Two New 230kV Lines from Unity to Tunstall	230/500	Apr-26	VA	140.0
Raines Sub - Interstate DP - 230kV Delivery-DEV-New 230kV Line from Tunstall to Raines	230	Apr-26	VA	20.0
Line #574 - Ladysmith to Elmont Rebuild - EOL	500	May-26	VA	91.3
Partial Line #26 (Buena Vista to Balcony Falls) Rebuild	115	Jun-26	VA	22.2
Lines #211 and #228 (Chesterfield to Hopewell) partial rebuild	230	Jun-26	VA	12.3
Line #2226 (Clover to Easters) Partial Rebuild (DNH)	230	Jun-26	VA	34.0
Nimbus 230kV Delivery - DEV	230	Jun-26	VA	12.0
Line #550 (Mount Storm to Valley) Rebuild	500	Jun-26	VA	256.0
Line #2172 Uprate - Brambleton to Evergreen	230	Jul-26	VA	2.3
Line #2210 Uprate - Brambleton to Evergreen Mills	230	Jul-26	VA	2.3
Line #2213 Uprate - Yardley to Cabin Run	230	Jul-26	VA	1.8
Stratus 230kV Delivery - DEV	230	Jul-26	VA	24.0
Park Center 230kV Delivery - DEV	230	Aug-26	VA	10.0

Appendix 2C-2 - List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Trabue Sub - Upgrade TX#1 - DEV	230	Aug-26	VA	11.0
Spartan - 230 kV Delivery - DEV	230	Sep-26	VA	15.4
Ocean Court 230kV Delivery - DEV	230	Oct-26	VA	12.7
Bring 2-230 kV Sources into White Oak SUB and Resolve 300 MW Load Loss Violation	230	Nov-26	VA	42.2
Possum Point 2nd 500-230kV TX (Ox Overloads) (PP 500kV - PP230kV)	230/500	Nov-26	VA	23.1
Idylwood - Convert Straight Bus to Breaker and a Half	230	Dec-26	VA	159.4
Line #108 (Boykins-Tunis) EOL Rebuild	115	Dec-26	NC	72.7
Line #126 (Earleys to Kelford) Partial Rebuild	115	Dec-26	NC	18.8
Line #2056 (Hornertown-Hathaway) EOL Rebuild	230	Dec-26	NC	49.1
Line #588 Yadkin-Fentress EOL Rebuild	500	Dec-26	VA	91.4
Jeffress Substation 230 kV Delivery (MEC)	230	Jan-27	VA	142.8
Brambleton Overdutied Breaker Replacement (SC102,H302, H402, 218302)	230	Mar-27	VA	5.6
Mars 2nd 500 -230 kV TX	230/500	May-27	VA	42.2
Bristers - 500-230 kV TX Expansion	230/500	May-27	VA	65.0
Line #265 Uprate - Sully to Takeoff	230	Aug-27	VA	4.6
Pegasus Sub 230kV Delivery - NOVEC	230	Nov-27	VA	28.5
Partial Line #83 (Craigsville-Staunton) EOL Rebuild	115	Mar-28	VA	23.0
Varina Substation - Add 2nd TX - DEV	230	May-28	VA	1.0
Cloverhill 230 kV Delivery - Add 4th and 5th TX - DEV	230	Jul-28	VA	1.3

Appendix 2D: Transmission Planning and System Reliability Analyses

I. Transmission System Planning & Operation Regulatory Background

The Company's transmission system is planned and operated to ensure adequate and reliable service to customers while meeting all regulatory requirements and standards. The Federal Energy Regulatory Commission ("FERC") provides oversight of the North American Electricity Reliability Corporation ("NERC"), which is the regulatory authority responsible for ensuring the reliability of the bulk power system across its six regions. The SERC Reliability Corp. ("SERC") is delegated responsibility for the southeastern and central regions of the United States, including the Company's transmission system. As a transmission owner ("TO"), the Company must comply with federally mandated NERC Reliability Standards, which constitute the minimum criteria with which all public utilities must comply.

The Company participates in numerous regional, inter-regional, and sub-regional studies to assess the reliability and adequacy of the interconnected transmission system. PJM is registered with NERC as the Company's Planning Coordinator, Transmission Planner ("TP"), and Transmission Operator ("TOP") and as a result, the Company must comply with PJM-specific reliability standards in addition to the NERC requirements. PJM holds two different types of Open Windows to address both reliability and market efficiency needs of the network: (1) the PJM Reliability Open Window, which supports the Regional Transmission Expansion Plan process ("RTEP") and addresses system reliability needs; and (2) the PJM Market Efficiency Open Window ("ME Open Window"), which aims to reduce market congestion and enhance grid efficiency.

The Company also utilizes an internal transmission planning process to evaluate its ability to support expected customer growth and determine if any transmission improvements are needed. If improvements are needed, the Company includes them in the PJM RTEP process as appropriate and seeks approval from the appropriate regulatory body.[1] Additionally, the Company performs seasonal operating studies, to identify facilities in its transmission system that could be critical during the upcoming season, and coordinates with neighboring utilities to maintain adequate levels of transfer capability to facilitate economic and emergency power flows.

Power system reliability is determined by both the transmission network and generation mix. Replacing traditional dispatchable, synchronous generation with renewable inverter-based resources ("IBR") introduces complexities regarding inertial and frequency response, short circuit response, and black-start capability—all components of power system reliability. The Company continues to work with PJM, the Commission, local officials, and other stakeholders on prioritizing projects critical to the reliability of the transmission system.

II. Reliability Study Background

In the context of the IRP, which only studies the DOM LSE for resource adequacy, it is important to understand that PJM's RTEP processes evaluate the entire PJM footprint and the Company's

[1] See Appendix 2C for a list of the Company's transmission projects selected by PJM.

transmission reliability at the DOM Zone level. This means that the transmission reliability analysis required to ensure NERC compliance assesses both the DOM LSE load and generation as well as all cooperatives and non-utility owned generation in the Company's service territory. Furthermore, although studies considering transmission network are a component of the IRP, it is important to reiterate that transmission planning and operations practices are dictated by the policies of FERC and NERC.

To allow the time necessary to complete a comprehensive transmission reliability analysis, work on the analysis was started in January 2025, using the 2024 PJM load forecast and the latest power flow cases from PJM's RTEP that utilized updated load, generation, and topology information. For the 2025 IRP Update, the Company updated the same four analyses described in Appendix 2D of the 2024 IRP. See Appendix 2D of the 2024 IRP for details on the methodologies used for these analyses.

- *An Import Limit Study for the DOM Zone*: The study is based on transmission system constraints and estimates how much power can flow through the transmission system. Importantly, it does not evaluate whether this power would be available for import. This analysis was completed first, beginning in April 2025, to understand the amount of power the transmission system can import.

- *An Inertial and Frequency Response Study*: The inertial and primary frequency response study evaluates how the integration of more IBRs will affect the system frequency. The study used the resource mix determined from the 2025 IRP Update modeling process for the Primary Portfolios and was completed in September 2025.

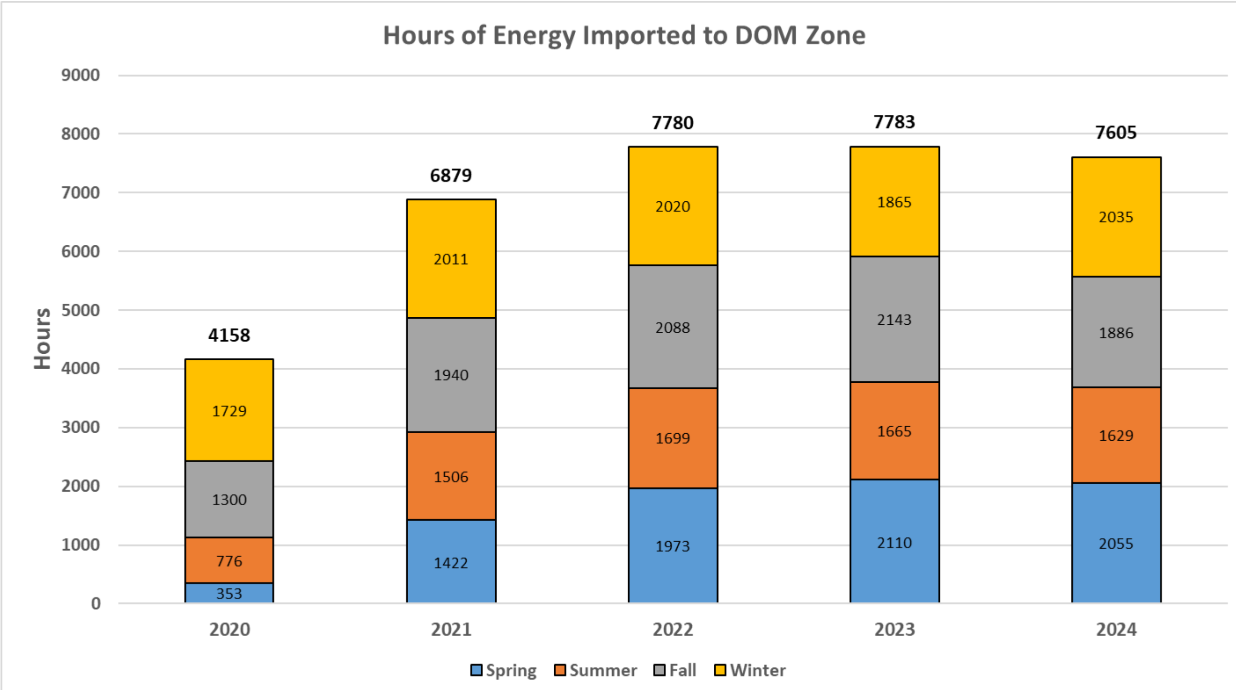
- *A Short Circuit System Strength Analysis*: Evaluates the system's capability to quickly recover after faults caused by physical damage to transmission lines or equipment (*e.g.*, due to storms), and assesses whether the internal controls of IBRs will still work in weak areas of the system. This study used the resource mix determined from the 2025 IRP Update modeling process for the Primary Portfolios and was completed in September 2025.
- *Review of System Restoration and Black Start Capabilities*

For additional explanation of some of the terms and concepts discussed below, see Section VII of Appendix 2D of the 2024 IRP.

III. Import Limit Study for the DOM Zone

The Company has historically and increasingly relied on imports from the PJM system to serve the needs of the DOM Zone load. See Figure 1 for hours of energy imported from 2020 through 2024. For example, in 2024, the Company imported power 86.82% of the time. This does not represent the amount of import the Company required but rather shows how the most economic dispatch could be achieved while not causing any thermal or voltage violations in the system.

Figure 1: Historical DOM Zone Energy Imports



The Transmission Network Import Analysis Studies examined seasonal import capability into DOM Zone in the future. The study performed considered the entire DOM Zone; however, the load growth associated with cooperative or non-LSE customers has a significant impact on the overall import capability to meet LSE customer load. The study results are outlined below.

The analysis utilized the 2024 PJM cases released for 2029, which included new projects selected and assumed to be in-service in 2029 to solve reliability violations. The PJM RTEP cases only include generators that have a signed Interconnection Service Agreement, but the Company included the Coastal Virginia Offshore Wind project, which will be completed before 2028, in the transmission import analysis for better accuracy. See Appendix 2D of the 2024 IRP for the methodology of how this analysis was performed.

This analysis found that the DOM Zone's import capability, based on the PJM 2024 RTEP for 2029, ranges between 16,631 MW in winter peak, 15,832 MW in summer peak, and 13,489 MW in shoulder months. These import capability limits are significantly higher than the DOM Zone's historical import levels which reached 7,500 MW, due to additional transmission infrastructure under construction and under development. Specifically, the significant increase in transmission import capability can be attributed to a 500 kV loop to be permitted and built in northern Virginia and an additional line to interconnect Dominion Energy with First Energy. The additional import capability shown in the 2025 analysis is due to the two additional 765 kV lines, which were approved by PJM as part of the Company's joint venture with AEP and First Energy. These new transmission lines were not built with the objective of increasing the import capability into the DOM Zone. They were built in response to reliability violations identified by PJM when developing the RTEP case to utilize for the Reliability Open Window for 2024. The fact that they do increase the import is a biproduct of the reliability needs.

Notably, the import analysis assessed the *capability* of the system to import power and does not assess the *availability* of energy to import to the DOM Zone. Federal and state policies incentivizing or mandating retirements of traditional dispatchable generation, increasing penetration of intermittent energy resources, and load growth may result in less energy available to import to the DOM Zone when needed, especially during extreme weather events.

The Company's PLEXOS modeling uses lower capacity and energy import limits than those found in the transmission import studies to help ensure energy independence and self-sufficiency for the Company's customers. Analysis demonstrates that during emergency periods, nearby neighbors will now need to import power to serve their internal load. This further confirms that the Company should be proactive in ensuring its own energy security through the buildout of internal generation. The increased capability of the transmission system provides value because it allows for economical dispatch of generation outside of the DOM Zone, but within the PJM footprint, during normal operations.

IV. Inertial and Frequency Response Study

The power system requires that there is an equal amount of energy generation (supply) and load (energy consumption or demand) across all instants in time, otherwise the frequency will deviate from the designed 60 Hertz ("Hz"). The resistance to change in frequency is characterized by the system's inertia, which allows the electric grid to control the regular frequency deviations caused by events such as load changes, transmission and distribution outages, generation shedding, and system instability. Synchronously rotating machines, such as traditional fossil-fueled, nuclear, or hydro plants, provide inertia, because they store kinetic energy in the turbine-generator rotors. If there is a sudden loss of generation, the power system draws on the stored kinetic energy to slow down the Rate of Change of Frequency ("RoCoF"), allowing the power system to maintain balance until reserve generators are brought online or until load is shed to achieve a longer-term balance. See Appendix 2D of the 2024 IRP for additional explanation of inertia, the important role it plays in maintaining system reliability, and the impact of traditional synchronously rotating generation and IBRs.

To examine synchronous inertial and frequency response, the Company evaluated the expected generation technology mix shown in each of the Primary Portfolios in terms of installed capacity together with the installed reserves. The inertial and frequency response transmission reliability analyses were performed using 2024 Summer Series model for 2029 developed by the Multiregional Modeling Working Group within the Eastern Interconnection Reliability Group. See Appendix 2D of the 2024 IRP for details on the methodology used for this analysis. As in 2024, the main contingency event studied across the three Primary Portfolios for each year between 2029 and 2045 was the trip and lockout of all units at the Greensville Power Plant. The Company also continued to analyze two scenarios: (1) the Company connected to the Eastern Interconnection ("EI"), allowing it to import power; and (2) the Company islanded with zero import capability. For these studies, because the DOM Zone is considered, all other synchronous generation, regardless of fuel type, is included in the analysis as there are no currently announced retirements from fossil units owned by different companies within the state.

The analysis continues to demonstrate that traditional synchronous generation resources provide inertia and help maintain system reliability. Inverter-based resources, however, cannot currently supply the inertia to maintain a balanced grid. As a result, the 2025 IRP Update's analysis demonstrates that the Forced Retirements by 2045 Portfolio has a less robust frequency response (RoCoF of 0.069 Hz/s) compared to the Company Preferred Plan and the Least Cost VCEA Compliant without EPA Portfolio (RoCoF of 0.06 Hz/s) when the Company is connected to the Eastern Interconnection ("EI").

When the Company is islanded, the RoCoF decreases from 0.36 Hz/s in 2029 to 0.27 Hz/s and 0.28 Hz/s for the Company Preferred Plan and Least Cost VCEA Compliant without EPA Portfolio, respectively, in 2045 due to the synchronous generation added to these portfolios and lack of retirements. For the Forced Retirement by 2045 Portfolio, because the Company retires synchronous generators with higher levels of inertia, the RoCoF increases from 0.36 Hz/s in 2029 to 0.41 Hz/s in 2045. This increase is offset due to the amount of nuclear added in the Forced Retirement by 2045 Portfolio.

It is worth noting that, although nuclear facilities do decrease the RoCoF by arresting changes in frequency immediately after a large load or generation disturbance, they support secondary frequency control, which is necessary for the power system to return to a stable equilibrium following a generation loss, differently than other synchronous generators. Due to their operational design, nuclear facilities cannot be used for meeting minimum operating reserve requirements.

The integration of Small Modular Reactors ("SMRs") planned in multiple portfolios will help support system frequency and inertia because they are synchronously rotating machines. Future technological advances may enable the inertia to be provided as "virtual inertia" by grid-forming inverters. Most of today's solar, wind, and storage inverters, however, are of a grid-following type that cannot supply virtual inertia. The control technology in grid following inverters does not allow them to set the voltage and frequency independent of synchronously rotating machines—thus they cannot support system frequency response actively.

V. Short-Circuit System Strength Analysis

A short circuit, or fault, is a system disturbance caused by an event such as a tree branch falling across electrical lines, a lightning strike, a balloon connecting between lines on a transmission tower, or a hurricane knocking down a transmission tower. When these short-circuit events occur, quickly removing the faulted energized equipment from service is critical for (i) ensuring personnel and public safety; (ii) preventing or reducing equipment failure; and (iii) maintaining the electric grid's stability. See Appendix 2D of the 2024 IRP for details on current short-circuit performance, the impacts of high penetrations of IBRs,[2] and the methodology used to conduct this analysis.

[2] FERC Order 901 has resulted in new NERC standards focused on IBR-specific protection standards including disturbance monitoring (PRC-028), ride-through performance (PRC-029), (ride-through performance), and post-event validation (PRC-030). Broader changes are still in progress and will take effect through 2030.

The results of the study are as follows for 2045 with variations in the amount of synchronous condensers to increase the pass rate:

- For the Company Preferred Plan:
  - 20,006 MW of solar and wind IBRs are added. If no synchronous condensers are added, 59% of the generation has a SCRIF over 3.5.
  - When 2,850 MVA of synchronous condensers are added, 73% of IBRs will have a SCRIF over 3.5.
  - When 4,275 MVA of synchronous condensers are added, 78% of IBRs will have a SCRIF over 3.5.
- For the Least Cost VCEA Compliant without EPA Portfolio:
  - 20,006 MW of solar and wind IBRs are added. If no synchronous condensers are added, 58% of the generation has a SCRIF over 3.5.
  - When 2,850 MVA of synchronous condensers are added, 72% of IBRs will have a SCRIF over 3.5.
  - When 4,275 MVA of synchronous condensers are added, 77% of IBRs will have a SCRIF over 3.5.
- For the Forced Retirements by 2045 Portfolio:
  - 26,486 MW of solar and wind IBRs are added. If no synchronous condensers are added, 58% of the generation has a SCRIF over 3.5.
  - When 2,850 MVA of synchronous condensers are added, 69% of IBRs will have a SCRIF over 3.5.
  - When 4,275 MVA of synchronous condensers are added, 72% of IBRs will have a SCRIF over 3.5.

VI. System Restoration and Black Start Capabilities

Large-scale blackouts can harm the public, the economy, and the power system. Thus, the ability to restore power to the system without external support (*i.e.*, black start) is crucial for ensuring system reliability. Most generators on the Company's system are not capable of black start, as it requires special equipment on-site. Black start units must be synchronous and dispatchable with constant and predictable output when operational. IBRs as they currently exist cannot meet the necessary standards. Theoretically, grid-forming technology can act as a black start resource for small areas, but it is not mature enough to rely on for ensuring offsite power to the Company's nuclear facilities. The Company continues, however, to investigate new technologies that may assist with ensuring a reliable and resilient system. NERC Reliability Standards and PJM Manuals set forth criteria for black start capacity.

For the Forced Retirements by 2045 Portfolio, where all carbon-emitting synchronous generation will be retired, with the technology currently available, it would not be possible to re-energize the system from a black start condition or meet the NERC standards surrounding system restoration.

Although the Company Preferred Plan and the Least Cost VCEA Compliant without EPA Portfolio evaluated included a significant amount of new intermittent renewable generation, they also maintain the majority of the Company's existing fleet of synchronous, dispatchable generation facilities, construct additional combined-cycle units and quick-start combustion turbines, and include the addition of SMRs. The combination of traditional generation resources with increasing penetration of renewable energy resources supports the reliability of the transmission system. Current black start restoration procedures start from the transmission system and quick-start dispatchable (synchronous) generation stations and then work toward restoring the distribution grid.

VII. Future Technology Considerations

As the grid continues to evolve and develop with an increasing penetration of renewable energy resources, so must the technology used to monitor, control, and transport energy. The Company will be evaluating how to effectively utilize technologies, including power quality compensation, reactive resources and voltage control, grid monitoring and control capabilities, energy storage requirements, and high-voltage direct current transmission. As newer technologies are developed, the Company will investigate their potential applicability. See Appendix 2D of the 2024 IRP for discussion of future technologies the Company continues to study.

Additionally, Dominion Energy is leading targeted initiatives in Grid-Forming ("GFM") technology to strengthen system stability, improve black start readiness, and enable higher levels of renewable integration. These efforts include the installation of a microgrid at the Locks Campus to evaluate the performance of GFM technology and conduct field demonstrations that validate control and protection strategies under real-world operating conditions. Another key initiative is a research collaboration with the Center for Power Electronics Systems at Virginia Tech focused on enabling black start capability for photovoltaic systems using advanced GFM inverter controls. Through simulation studies this project demonstrates the ability of GFM inverters to regulate frequency, maintain voltage stability, and synchronize with conventional generators during system restoration. Additionally, through the Department of Energy-funded Analytics and Control for Driving Capital Efficiency project, Dominion Energy is piloting a unique GFM inverter on an active renewable interconnection to expand grid management capabilities, enhance inverter-based resource control, and develop protocols for rural microgrid enablement and GFM widespread adoption. These demonstrations will be critical to understanding the black start capabilities of IBR generators in the future.

The Company continues to investigate Grid Enhancing Technologies ("GETs") to support the existing transmission network. GETs are a group of technologies that offer a variety of benefits and provide operational flexibility and potentially improve grid performance, which can come in the form of both software or hardware solutions.

The Company has evaluated, used, and continues to evaluate the use GETs technologies as they relate to the transmission system as follows:

- **Advanced Conductors:** In 2019, the Company standardized its use of a high-temperature conductor, like aluminum conductor steel supported, on all 230 kV reconductor and new-build projects. This resulted in a 50% increase in capacity over the Company's legacy lines.

- **Dynamic Line Ratings ("DLRs"):** In 2024, the Company was a recipient of the Grid Resilience and Innovations Partnership grant through the Infrastructure Investment and Jobs Act for the Company's Analytics and Control for Driving Capital projects. In part, the grant funds will be used to install, calibrate, and operationalize the advanced line rating systems of approximately 20 lines, primarily within the Northern Virginia region of the Dominion Energy Virginia transmission network. It will be among the first and largest deployments of DLR in the United States, with installation beginning in 2025 and anticipated new ratings will be incorporated into the Energy Management System by the end of 2026. The Company will coordinate with PJM to implement the ratings for these lines in summer 2026.
- **Flexible AC Transmission Systems ("FACTs"):** FACTs devices strengthen and support the transmission grid by providing variable voltage support of the transmission network. The Company was an early adopter of the FACTs devices and has several types of FACTS devices connected to the transmission system, including eight stationery and three mobile Static Synchronous Compensators ("STATCOMs") and three Static VAR Compensators ("SVCs"). PJM approved the addition of five stationery STATCOMs and three mobile STATCOMs, which will be installed in the next several years. While FACTs are helpful, they use inverter technology, which limits the amount of current it can supply to a fault. The Company is exploring the use of FACTs devices combined with grid-forming capabilities to further enhance their usefulness.
- **Fixed Series Capacitor Banks ("FSCs"):** FSCs reduce line losses and enhance electrical angular coordination to prevent generator instability during faults. The Company deployed two FSCs to ensure stable operation of the world's second largest pump storage facility, Bath County, at maximum output.
- **Advanced Power Flow Controllers ("APFCs"):** In 2021, to alleviate overloads on a 230 kV line, the Company identified that installing a 2.2-ohm series reactor on the line would reduce the overload in the near-term. The series reactor was placed in service in 2023. The Company plans to continue to evaluate APFCs as possible solutions during PJM Reliability Open Windows.
- **Storage as a transmission asset ("SATA"):** As part of the 2025 PJM Market Efficiency Open Window, the Company proposed a 50 MW battery to alleviate congestion PJM identified. The proposals are currently in review and will be awarded by December 2025. PJM is currently reviewing how to integrate SATA into the transmission planning and market constructs, and the Company will continue to monitor PJM's review efforts to ensure that its future proposals could be viable.
- **Topology Optimization:** The Company works with PJM in real-time operations to optimize topology to support system reliability. The current use of topology optimization is based on manually identified locations that have been determined and evaluated, but programmatic topology optimization is being evaluated. PJM suggests avoiding topology optimization as a unique solution to an identified planning problem, which is consistent with FERC's requirements in Order 1920.

Notably, all the projects described above are planned through the PJM RTEP Process described in Section I and further investment in these technologies will also be evaluated through the RTEP process. While GETs are and will continue to be a supporting technology, long-term investments in generation and transmission are still needed to ensure that the DOM Zone and DOM LSE can meet energy needs in the future.

Appendix 2E: Renewable Energy Interconnection and Integration Costs

I. Background on Renewable Energy Interconnection and Integration Costs

The integration of intermittent renewable energy generation into the electric grid involves multiple considerations. The generator must first be physically interconnected to the electric grid, either at the transmission or distribution level. The developer of a generating facility typically pays the costs to physically interconnect the resource, including any upgrades required near the point of interconnection to ensure grid stability. As increasing volumes of renewable energy generation are interconnected to the grid, additional system-level upgrades must be made by the Company to integrate new resources and address grid stability and reliability issues caused by the intermittent nature of these resources. All of these costs are incorporated in the NPV for "Total System Costs," as shown in Table 5.1.1.2 in the 2025 IRP Update.

In addition to interconnections costs, the 2025 IRP Update includes three categories of system upgrades costs:

(1) **Transmission Integration Costs:** These costs represent physical enhancements to the transmission system needed to resolve low voltage and thermal conditions caused by integrating significant volumes of solar generation.

(2) **Generation Re-dispatch Costs:** This category represents costs resulting from real -time variability of load and generator availability compared to day-ahead forecasted load and generator availability.

(3) **Regulating Reserves Costs:** This category represents ancillary payments the Company must make to resources to ensure that the system can balance intra-day or intra-hour differences in load and generation.

The sections below explain the analyses performed for each of these three categories. While the Company has refined its methods to estimate the renewable energy integration costs compared to prior IRPs, more analysis is required to fully assess the necessary grid modifications and associated costs of integrating increasing amounts of solar generation.

II. Transmission Integration Costs

The transmission integration costs were assessed by performing a steady state power flow and contingency analysis when a total of 10 GW and 20 GW of solar generation is present on the transmission grid. The analysis was performed based on real projects proposed and currently in PJM Interconnection LLC's ("PJM") generation interconnection queue to best reflect the interconnection locations, sizes, and behaviors of the solar developers. The actual proposed projects in the PJM Queue at the time of this analysis are 40,629 MW. Because of the large number of projects, the Company has sufficient data without extrapolating for unknown projects. The resulting power flow violations results were then used to calculate the cost per kilowatt ("kW") of enhancements to the Company's transmission system.

In previous years, the Company studied up to 30,000 MWs of solar power integration by scaling generation at known locations for solar projects. However, because the VCEA and RPS requirements do not require that the Company build to that projection, it was determined that a more useful calculation for this analysis would be at 10,000 MWs and 20,000 MWs.

All Portfolios include the addition of significantly more solar generation. Figure 1 shows the integration costs assumed for Company-build solar as additional solar generation is added to the system. For Company-build solar up to 5,000 MWs the Company utilized a transmission interconnect cost of 250 per kw. This value is based on historical interconnection costs for projects between 3 and 75MWs.

Figure 1 – Total Solar Integration Costs

Solar MW	Total Cost
Up to 5,000	$250 per kw
5,000 - 10,000	$127.96 per kW
10,000- 20,000	$108.57 per kW

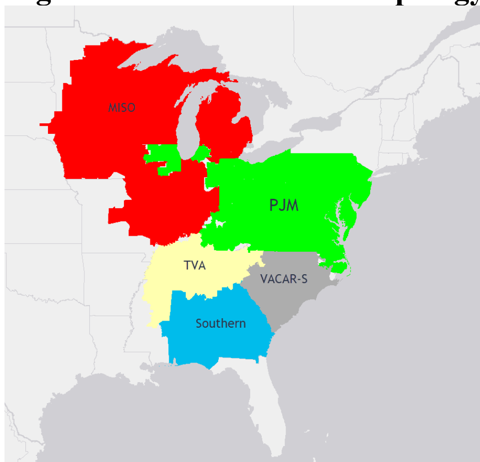
III. Generation Re-dispatch Costs

Re-dispatch generation costs are defined as additional costs that are incurred due to the unpredictability of events that occur during a typical day. Historically, these types of events were driven by load variations due to actual weather that differs from the forecast. Most power system operators assess the generation needs for a future period based on load forecasts and commit a series of generators to be available during a given period. These committed generators are expected to operate in an hour-to-hour sequence that minimizes total cost. Once within that period, actual load may vary, and the committed generators may operate in a less than optimal hour-to-hour sequence. The resulting additional costs due to real-time variability are known as re-dispatch costs.

Increasing amounts of intermittent generation increase the uncertainty about re-dispatch costs. The Company performed a simulation analysis to determine the cost impact on generation operations at varying levels of solar, onshore wind, and offshore wind penetration. To study the effects of these intermittent resources, the Company studied historic wind speed and solar irradiance data from the National Renewable Energy Laboratory ("NREL").

For this analysis, the Company utilized the Aurora planning model with a regional simulation topology consisting of PJM, VACAR South, Southern Company, Tennessee Valley Authority, and large sections of Midwest ISO (see Figure 2 below). The results from the Aurora model captured not only the DOM Zone hourly prices interactively, but also the potential system cost impacts from intermittent resources outside the Company's service territory.

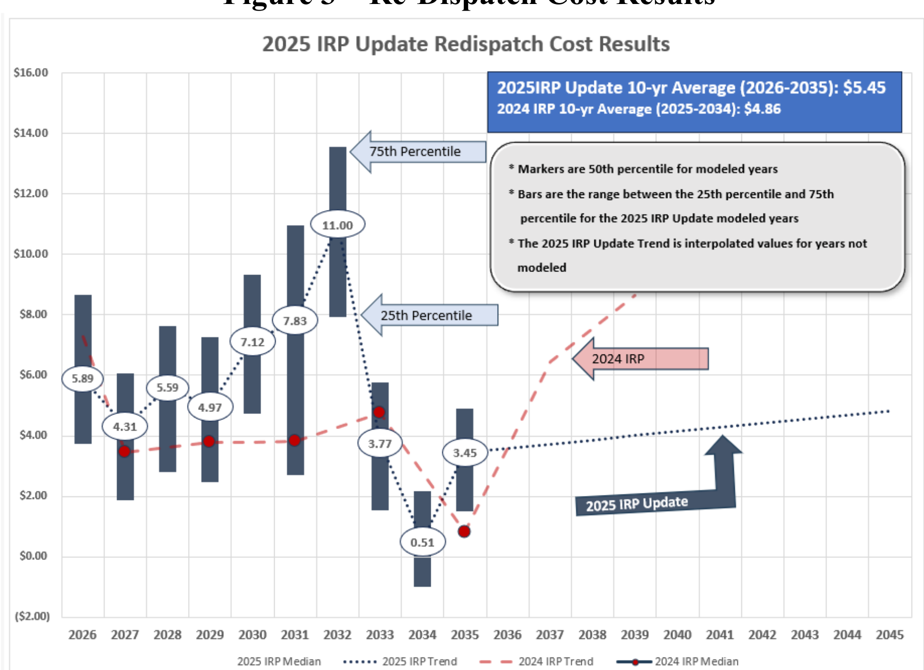
Figure 2 – Aurora Model Topology



For each simulation year, the Company performed a base case Aurora simulation by using the base hourly renewable generation profiles to establish the base case commitment decisions. Using these commitment decisions, the Company performed an additional 200 simulations applying different hourly renewable profiles from the NREL historical weather patterns studies to re-optimize the system cost.

The total system cost for each simulation was compared to the base case system cost of the same year. This difference depends on the differences in fuel cost, variable operations and maintenance ("O&M") cost, emission cost, and purchase and sale costs. The re-dispatch cost is the delta of the system cost divided by the Company's expected total renewable generation. The re-dispatch cost results are outlined in Figure 3.

Figure 3 – Re-Dispatch Cost Results



IV. Regulating Reserve Costs

Regulating reserves are the additional reserves needed to balance the uncertainty of forecast errors in net load that occur during a typical day. These reserves exclude contingency reserves, which are needed to meet the loss of a major power system generation or transmission system asset. Within the PJM market, these regulating reserves are an ancillary service, the cost of which is charged to customers. Revenues collected for this ancillary service are paid to resources available to supply or reduce energy to correct forecast errors. Unlike contingency reserves, regulating reserves are needed to either increase or decrease generation in any given operational hour. Regulating reserves provide the capability to re-dispatch quickly. Re-dispatch costs are those associated with the actual dispatch of the regulating resources.

Historically, the level of regulating reserves was primarily driven by the uncertainty associated with load during any given operating day. The intermittent nature of solar and wind generation adds to this uncertainty, necessitating an increase in the levels of regulating to compensate for this added uncertainty.

A variety of resources can be used to address system uncertainty: energy storage, unscheduled CT capacity, unscheduled duct burner capacity (on scheduled combined-cycle units), intraday purchases and sales, and interruptible load.

In order to assess the regulating reserves required by increasing volumes of solar generation, the Company utilized the Electric Power Research Institute Dynamic Assessment and Determination of Operating Reserves tool. This tool calculates operating reserves based on correlations to other variables (e.g., forecasted generation, time of day) and can be used to evaluate solar, wind, and load variations separately and in combination. The reserves volume required is then reduced by the expected geographic diversity of the resources and technological diversity of these resources (wind vs. solar).

The next step was to determine a market price for these reserves. This was based on a historical analysis of PJM day-ahead secondary reserves and is capped by the cost of new entry of a new combustion turbine resource. The results of the Company Preferred Plan show that the hourly cost of regulating reserves gradually increases from $1.17/MWh in 2026 to over $19.00/MWh in 2045 timeframe. This occurs because the demand for regulating reserves in PJM is projected to outpace the supply. The forecasts of resource additions are based on ICF projections in states other than Virginia. Virginia resource additions are based on the projections in this 2025 IRP Update for the Company. For Appalachian Power Company and other sellers of electric power in Virginia, the projections assume solar and wind resource additions according to the RPS requirements for Appalachian Power Company. From the Company's perspective, regulating reserve costs will be incurred when the regulating costs to serve the Company's load exceed the revenue received from PJM for the Company units that supply this ancillary service.

2025 IRP Update Dominion Energy Virginia
Net Regulating Reserves:

Year	Company Preferred Plan	Least Cost VCEA Compliant without EPA	Forced Retirements by 2045
2026	$0	$0	$0
2027	$0	$0	$0
2028	$0	$0	$0
2029	$0	$0	$0
2030	$0	$0	$0
2031	$0	$0	$0
2032	$0	$0	$0
2033	$0	$0	$0
2034	$0	$0	$0
2035	$0	$0	$0
2036	$0	$0	$0
2037	$0	$0	$0
2038	$0	$0	$0
2039	$0	$0	$0
2040	$0	$0	$0
2041	$0	$0	$0
2042	$9	$9	$0
2043	$54	$54	$0
2044	$102	$102	$0
2045	$150	$150	$0

Appendix 3A(i-iii) - Capacity Information Directed by the SCC

	2025 PJM Load Forecast			
	Coincident Peak (CP)		Non-Coincident Peak (NCP)	
Year	DOM Zone Summer Forecast	LSE Equivalent	DOM Zone Summer Forecast	LSE Equivalent
2025	22,667	17,296	23,351	17,872
2026	24,193	17,589	24,868	18,157
2027	26,019	17,814	26,732	18,413
2028	28,257	18,103	29,002	18,729
2029	30,488	18,579	31,237	19,209
2030	32,666	19,091	33,431	19,734
2031	35,152	19,676	35,916	20,318
2032	37,315	20,314	38,073	20,951
2033	39,116	20,970	39,883	21,615
2034	40,692	21,642	41,452	22,281
2035	42,105	22,360	42,846	22,983
2036	43,369	23,084	44,117	23,713
2037	44,499	23,794	45,243	24,419
2038	45,496	24,425	46,269	25,075
2039	46,354	24,927	47,135	25,584
2040	47,191	25,484	47,956	26,127
2041	47,963	26,048	48,733	26,696
2042	48,682	26,640	49,436	27,274
2043	49,395	27,236	50,160	27,880
2044	50,096	27,831	50,879	28,490
2045	50,842	28,451	51,604	29,092

Appendix 3A(iv-v): Capacity Information Directed by the SCC

IRP Unit Name	Nameplate
Altavista	71.1
Bath County 1	477.0
Bath County 2	477.0
Bath County 3	477.0
Bath County 4	477.0
Bath County 5	477.0
Bath County 6	477.0
Bear Garden	559.0
Bookers Mill Solar	127.0
Brunswick	1472.2
Camelia Solar	20.0
Cavalier PPA	155.0
Chesapeake CT 1, 4, 6	51.1
Chesapeake PPA	118.0
Chesterfield 7	219.4
Chesterfield 8	227.2
Clover 1	424.0
Clover 2	424.0
Colonial Trail West	142.4
CVOW (Demonstration)	12.0
Darbytown 1	92.1
Darbytown 2	92.1
Darbytown 3	92.1
Darbytown 4	92.1
Dry Bridge Storage	20.0
Elizabeth River 1	129.6
Elizabeth River 2	129.6
Elizabeth River 3	129.6
Fountain Creek Solar	80.0
Gaston Hydro	177.6
Gordonsville 1	150.2
Gordonsville 2	150.2
Grassfield Solar	20.0
Gravel Neck 1-2	24.0
Gravel Neck 3	91.9
Gravel Neck 4	91.9
Gravel Neck 5	91.9
Gravel Neck 6	91.9
Greensville	1773.3
Hopewell	71.1

Appendix 3A(iv-v): Capacity Information Directed by the SCC

IRP Unit Name	Nameplate
Ladysmith 1	178.5
Ladysmith 2	178.5
Ladysmith 3	178.5
Ladysmith 4	178.5
Ladysmith 5	178.5
Lowmoor CT 1-4	65.0
Mount Storm 1	570.2
Mount Storm 2	570.2
Mount Storm 3	522.0
Mount Storm CT	18.5
Norge Solar	20.0
North Anna 1	979.7
North Anna 2	979.7
North Anna Hydro	10.0
Northern Neck CT 1-4	65.7
Otter Creek Solar	60.0
Piney Creek Base Solar	80.0
Pleasant Hill PPA	20.0
Possum Point 6	613.0
Possum Point CT 1-6	93.4
Quillwort Solar	18.0
Remington 1	178.5
Remington 2	170.0
Remington 3	178.5
Remington 4	178.5
Rivanna PPA	12.5
Roanoke Rapids Hydro	95.0
Rosemary	180.0
Sadler Solar	100.0
Scott Solar	17.0
Sebera Solar	18.0
Solidago Solar	20.0
Southampton	71.1
Spring Grove	97.9
Stratford PPA	15.0
Surry 1	847.5
Surry 2	847.5
Sycamore Solar	42.0
Virginia City Hybrid Energy Center	668.0
Warren	1472.2

Appendix 3A(iv-v): Capacity Information Directed by the SCC

IRP Unit Name	Nameplate
Water Strider PPA	80.0
Watlington PPA	20.0
Westmoreland PPA	20.0
Whitehouse Solar	20.2
Winterberry Solar	20.0
Woodland Solar	19.1
Wythe 2 PPA	75.0

Appendix 3B-1 – Existing Generation Units in Service

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name[(1)]	Location	Unit Class	Primary Fuel Type	C.O.D.[(2)]	MW Summer
Altavista	VA	Baseload	Biomass	1992	51
Hopewell	VA	Baseload	Biomass	1989	51
Southampton	VA	Baseload	Biomass	1992	51
Clover 1	VA	Intermediate	Coal	1995	220
Clover 2	VA	Intermediate	Coal	1996	219
Mount Storm 1	WV	Baseload	Coal	1965	542
Mount Storm 2	WV	Baseload	Coal	1966	552
Mount Storm 3	WV	Baseload	Coal	1973	520
Virginia City Hybrid Energy Center	VA	Baseload/Intermediate	Coal	2012	610
Gaston Hydro	NC	Intermittent	Hydro	1963	220
North Anna Hydro	VA	Intermittent	Hydro	1987	1
Roanoke Rapids Hydro	NC	Intermittent	Hydro	1955	95
Chesapeake CT 1, 4, 6	VA	Peak	Light Oil	1967	39
Gravel Neck 1-2	VA	Peak	Light Oil	1970	28
Lowmoor CT 1-4	VA	Peak	Light Oil	1971	48
Mount Storm CT	WV	Peak	Light Oil	1967	11
Northern Neck CT 1-4	VA	Peak	Light Oil	1971	47
Possum Point CT 1-6	VA	Peak	Light Oil	1968	72
Rosemary	NC	Peak	Light Oil	1990	143
Bear Garden	VA	Baseload/Intermediate	Natural Gas	2011	622
Brunswick	VA	Baseload/Intermediate	Natural Gas	2016	1,409
Chesterfield 7	VA	Intermediate	Natural Gas	1990	191
Chesterfield 8	VA	Intermediate	Natural Gas	1992	195
Gordonsville 1	VA	Intermediate	Natural Gas	1994	109
Gordonsville 2	VA	Intermediate	Natural Gas	1994	109
Greensville	VA	Baseload/Intermediate	Natural Gas	2018	1,588
Possum Point 6	VA	Baseload/Intermediate	Natural Gas	2003	571
Warren	VA	Baseload/Intermediate	Natural Gas	2014	1,381
Darbytown 1	VA	Peak	Natural Gas	1990	85
Darbytown 2	VA	Peak	Natural Gas	1990	85
Darbytown 3	VA	Peak	Natural Gas	1990	85
Darbytown 4	VA	Peak	Natural Gas	1990	85
Elizabeth River 1	VA	Peak	Natural Gas	1992	109
Elizabeth River 2	VA	Peak	Natural Gas	1992	107
Elizabeth River 3	VA	Peak	Natural Gas	1992	109
Gravel Neck 3	VA	Peak	Natural Gas	1989	85
Gravel Neck 4	VA	Peak	Natural Gas	1989	85
Gravel Neck 5	VA	Peak	Natural Gas	1989	85
Gravel Neck 6	VA	Peak	Natural Gas	1989	85

Appendix 3B-1 – Existing Generation Units in Service

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name[1]	Location	Unit Class	Primary Fuel Type	C.O.D.[2]	MW Summer
Ladysmith 1	VA	Peak	Natural Gas	2001	155
Ladysmith 2	VA	Peak	Natural Gas	2001	154
Ladysmith 3	VA	Peak	Natural Gas	2008	160
Ladysmith 4	VA	Peak	Natural Gas	2008	160
Ladysmith 5	VA	Peak	Natural Gas	2009	161
Remington 1	VA	Peak	Natural Gas	2000	150
Remington 2	VA	Peak	Natural Gas	2000	151
Remington 3	VA	Peak	Natural Gas	2000	162
Remington 4	VA	Peak	Natural Gas	2000	152
North Anna 1	VA	Baseload	Nuclear	1978	838
North Anna 2	VA	Baseload	Nuclear	1980	835
Surry 1	VA	Baseload	Nuclear	1972	838
Surry 2	VA	Baseload	Nuclear	1973	838
Chesapeake PPA	VA	Intermittent	Solar	2024	20
Pleasant Hill PPA	VA	Intermittent	Solar	2023	3
Rivanna PPA	VA	Intermittent	Solar	2024	2
Watlington PPA	VA	Intermittent	Solar	2023	3
Wythe 2 PPA	VA	Intermittent	Solar	2024	11
Stratford PPA	VA	Intermittent	Solar	2023	2
Water Strider PPA	VA	Intermittent	Solar	2021	11
Westmoreland PPA	VA	Intermittent	Solar	2021	3
Grassfield Solar	VA	Intermittent	Solar	2022	3
Norge Solar	VA	Intermittent	Solar	2023	3
Sycamore Solar	VA	Intermittent	Solar	2023	5
Black Bear Distributed	VA	Intermittent	Solar	2023	0
Springfield Distributed	VA	Intermittent	Solar	2024	0
Camellia Solar	VA	Intermittent	Solar	2024	2
Fountain Creek Solar	VA	Intermittent	Solar	2024	14
Otter Creek Solar	VA	Intermittent	Solar	2024	9
Piney Creek Base Solar	VA	Intermittent	Solar	2023	11
Quillwort Solar	VA	Intermittent	Solar	2024	3
Sebera Solar	VA	Intermittent	Solar	2024	3
Solidago Solar	VA	Intermittent	Solar	2023	3
Winterberry Solar	VA	Intermittent	Solar	2023	3
CVOW (Demonstration)	VA	Intermittent	Wind	2021	7
Scott Solar	VA	Intermittent	Solar	2016	3
Whitehouse Solar	VA	Intermittent	Solar	2016	3
Woodland Solar	VA	Intermittent	Solar	2016	3
Colonial Trail West	VA	Intermittent	Solar	2019	20

Appendix 3B-1 – Existing Generation Units in Service

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name[1]	Location	Unit Class	Primary Fuel Type	C.O.D.[2]	MW Summer
Spring Grove	VA	Intermittent	Solar	2020	14
Sadler Solar	VA	Intermittent	Solar	2021	14
Bath County 1	VA	Intermediate	Pumped Storage	1985	302
Bath County 2	VA	Intermediate	Pumped Storage	1985	302
Bath County 3	VA	Intermediate	Pumped Storage	1985	302
Bath County 4	VA	Intermediate	Pumped Storage	1985	302
Bath County 5	VA	Intermediate	Pumped Storage	1985	302
Bath County 6	VA	Intermediate	Pumped Storage	1985	302
Dry Bridge Storage	VA	Peak	Grid	2023	9
Cavalier PPA	VA	Intermittent	Solar	2024	22
Bookers Mill Solar	VA	Intermittent	Solar	2025	19

Subtotal - Base	5,115
Subtotal - Baseload/Intermediate	6,181
Subtotal - Intermediate	2,851
Subtotal - Peak	2,804
Subtotal - Intermittent	532
Total	17,483

Note: Summer MW's for solar generation (renewables) represents firm capacity.

(1) Exisiting generators as of 2025

(2) Commercial operation date

Appendix 3B-2 - Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Purchase Power Agreement (PPA) Units[(1)]					
Aditya Solar	VA	Solar	11,000	8/21/2023	8/20/1936
Alexandria/Arlington - Covanta	VA	MSW	28,500	1/29/1988	12/31/2036
Alpha Value Solar	NC	Solar	20,000	7/9/2020	9/9/2033
Aulander Hwy 42 Solar	NC	Solar	5,000	12/30/2016	12/29/2031
Banister Hydro	VA	Hydro	1,800	9/28/1988	Auto renew
Barnhill Road Solar	NC	Solar	3,000	11/30/2016	11/29/2031
Battleboro Farm Solar	NC	Solar	5,000	2/17/2016	2/16/2031
Battleboro Solar	NC	Solar	5,000	10/7/2016	10/6/2031
Bethel Price Solar	NC	Solar	5,000	12/9/2014	12/8/2029
Bethel Solar	NC	Solar	4,000	3/3/2016	3/2/2031
Bradley PVI- FAE IX	NC	Solar	5,000	2/4/2016	2/3/2031
Brasfield Dam	VA	Hydro	2,800	10/12/1993	Auto renew
Buckingham II Solar	VA	Solar	20,000	7/28/2021	7/27/2034
Burnshire Hydroeltric	VA	Hydro	100	7/11/2016	Auto renew
Camden Dam Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Carl Friedrich Gauss Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Cavalier Solar	VA	Solar	155,000	6/5/2024	6/4/2044
Chesapeake Solar (Shillaugh)	RUS	Solar	118,000	12/20/2023	12/19/2043
Chowan Jehu Road Solar	NC	Solar	5,000	2/9/2018	2/8/2033
Citizens Hertford	NC	Solar	16,200	6/6/2019	6/5/2029
Columbia Mills	VA	Hydro	343	2/7/1985	Auto renew
Conetoe Solar	NC	Solar	5,000	2/5/2016	2/4/2031
Cork Oak Solar	NC	Solar	20,000	12/29/2017	12/28/2027
Cottonwood Solar	NC	Solar	5,000	1/25/2018	1/24/2033
Creswell Aligood Solar	NC	Solar	14,000	5/13/2015	5/12/2030
Cushaw Hydro	VA	Hydro	7,000	11/21/2018	11/20/2033
Davis Lane Solar	NC	Solar	5,000	12/31/2017	12/30/2032
Dogwood Solar	NC	Solar	20,000	12/9/2014	12/8/2029
Downs Farm Solar	NC	Solar	5,000	12/1/2015	11/30/2030
Essex Solar Center	VA	Solar	20,000	12/14/2017	12/13/2037
Everetts Wildcat Solar	NC	Solar	5,000	3/11/2015	3/10/2030
Endless Caverns	VA	Solar	31,400	12/14/2017	12/13/2037
FAE X - Shawboro	NC	Solar	20,000	1/26/2016	1/25/2031
FAE XIX- American Legion PVI	NC	Solar	20,000	1/2/2018	1/1/2033
FAE XVII - Watson Seed	NC	Solar	20,000	1/28/2016	1/27/2031
FAE XVIII - Meadows	NC	Solar	20,000	6/9/2016	6/8/2031
FAE XXI -Benthall Bridge PVI	NC	Solar	5,000	1/30/2017	1/29/2032
FAE XXII - Baker PVI	NC	Solar	5,000	1/30/2017	1/29/2032
FAE XXV-Vaughn's Creek	NC	Solar	20,000	1/2/2018	1/1/2033
FAE XXXIII - Grandy	NC	Solar	20,000	3/13/2020	3/12/2030
FAE XXXIV - Underwood	NC	Solar	16,000	10/23/2020	10/22/2030
FAE XXXV - Turkey Creek	NC	Solar	13,500	1/31/2017	1/30/2027
Five Forks Solar	NC	Solar	20,000	12/23/2019	12/22/2029
Flat Meeks- FAE II	NC	Solar	5,000	10/27/2017	10/26/2032
Floyd Road Solar	NC	Solar	5,000	6/19/2017	6/18/2032
Garysburg Solar	NC	Solar	5,000	3/18/2016	3/17/2031
Gaston Solar	NC	Solar	5,000	4/18/2016	4/17/2031

Appendix 3B-2 - Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Gates Solar	NC	Solar	5,000	2/8/2016	2/7/2031
GKS Solar- SolNC2	NC	Solar	5,000	12/16/2015	12/15/2030
Gliden Solar	NC	Solar	5,000	12/30/2020	12/29/2035
Green Farm Solar	NC	Solar	5,000	1/6/2016	1/5/2031
Hardison Farm Solar	NC	Solar	5,000	9/9/2016	9/8/2031
Hemlock Solar	NC	Solar	20	12/5/2016	12/4/2031
Hertford Solar	NC	Solar	10,000	8/3/2022	8/2/2027
Hickory Solar	VA	Solar	15,700	9/8/2020	9/7/2033
Highway -158 PVI	NC	Solar	9,000	11/10/2020	11/9/2030
Hollyfield II Solar	VA	Solar	13,000	7/22/2021	7/21/2034
HXNAir Solar One	NC	Solar	5,000	12/21/2017	12/20/2032
HXOap Solar	NC	Solar	20,000	12/16/2014	12/15/2029
Jakana Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Jamesville Road	NC	Solar	5,000	9/10/2019	9/9/2033
Lakeview Hydro	VA	Hydro	400	12/22/1988	Auto renew
Leggett Solar	NC	Solar	5,000	12/14/2016	12/13/2031
Lewiston Solar	NC	Solar	5,000	12/18/2014	12/17/2029
Long Farm 46 Solar	NC	Solar	5,000	2/12/2016	2/11/2031
MC1 Solar	NC	Solar	5,000	8/19/2016	8/18/2031
Westvaco	VA	Coal/Biomass	154,000	6/18/1981	8/25/2088
Mill Pond Solar	NC	Solar	5,000	8/7/2019	8/6/2034
Modlin Farm Solar	NC	Solar	5,000	9/14/2016	9/13/2031
Mt Jackson I Solar	VA	Solar	15,650	6/14/2021	6/13/2034
Nokesville Solar	VA	Solar	20,000	11/22/2022	11/21/2035
North 301	NC	Solar	20,000	12/18/2019	12/17/2029
Northern Cardinal Solar	NC	Solar	2,000	6/29/2018	6/28/2033
Pamplin Solar	VA	Solar	19,700	7/13/2020	7/12/2033
Phelps 158 Solar Farm	NC	Solar	5,000	2/26/2018	2/25/2033
Pleasant Hill Solar	RUS	Solar	20,000	6/15/2023	6/14/2043
Plymouth Solar	NC	Solar	5,000	10/4/2012	10/3/2027
Rappahhannock Solar	VA	Solar	1,500	11/24/2021	11/23/2036
Rivanna	VA	Solar	12,500	11/15/2024	11/14/2044
River Road Solar	NC	Solar	5,000	8/23/2016	8/22/2031
Rives Road Solar	VA	Solar	5,000	5/15/2020	5/14/2033
Ryland Road Solar	NC	Solar	5,000	8/17/2021	9/9/2033
Sandy Solar	NC	Solar	5,000	5/30/2018	5/29/2033
Schell Solar Farm	NC	Solar	5,000	12/22/2016	12/21/2031
Seaboard Solar	NC	Solar	5,000	6/29/2016	6/28/2031
Shiloh Hwy 1108 Solar	NC	Solar	5,000	2/9/2018	2/8/2033
Simons Farm Solar	NC	Solar	5,000	7/13/2016	7/12/2031
Stone Container	VA	Coal/biomass	48,400[3]	3/21/1981	Auto renew
SolNC10 Solar	NC	Solar	5,000	1/13/2016	1/12/2031
SolNC3 Solar-Sugar Run Solar	NC	Solar	5,000	2/5/2016	2/4/2031
SolNC5 Solar	NC	Solar	5,000	5/12/2015	5/11/2030
SolNCPower6 Solar	NC	Solar	5,000	11/1/2015	10/31/2030
Stratford Solar	RUS	Solar	15,000	1/4/2023	1/3/2043
Sun Farm V Solar	NC	Solar	5,000	11/30/2018	9/9/2033
Sun Farm VI Solar	NC	Solar	5,000	11/28/2018	9/9/2033

Appendix 3B-2 - Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Sun Farm VIII	NC	Solar	3,975	12/17/2020	9/9/2033
Sunflower Solar	NC	Solar	16,000	12/29/2017	12/28/2027
Tarboro Solar	NC	Solar	5,000	12/31/2015	12/30/2030
Tredegar Solar	VA	Solar	480	11/18/2022	11/17/2032
TWE Ahoskie Solar Project	NC	Solar	5,000	1/12/2018	1/11/2033
TWE Kelford Solar	NC	Solar	4,700	6/6/2016	6/5/2031
Two Mile Desert Road - SolNC1	NC	Solar	5,000	8/10/2015	8/9/2030
W. E. Partners 1	NC	Biomass	100	4/26/2013	Auto renew
W. E. Partners II	NC	Biomass	300	3/15/2012	Auto renew
Water Strider Solar	VA	Solar	80,000	5/15/2021	5/14/2041
Watlington Solar	RUS	Solar	20,000	3/29/2023	3/28/2043
Westmoreland County Solar	VA	Solar	20,000	10/22/2021	10/21/2041
Weyerhaeuser/Domtar	NC	Coal/biomass	28,400(2)	7/27/1991	Auto renew
Whitakers Farm Solar	NC	Solar	3,400	7/20/2016	7/19/2031
White Farm Solar	NC	Solar	5,000	8/26/2016	8/25/2031
Whitehurst PVI Solar	NC	Solar	10,000	3/13/2020	3/12/2035
Williamston Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Williamston Speight Solar	NC	Solar	15,000	11/23/2016	11/22/2031
Williamston West Farm Solar	NC	Solar	5,000	8/23/2016	8/22/2031
Windsor Cooper Hill Solar	NC	Solar	5,000	12/18/2015	12/17/2030
Windsor Hwy 17 Solar	NC	Solar	5,000	8/28/2021	9/9/2033
Windsor Solar	NC	Solar	5,000	12/17/2014	12/16/2029
Winton Solar	NC	Solar	5,000	2/8/2016	2/7/2031
Woodland Solar	NC	Solar	5,000	4/7/2016	4/6/2031
Wythe Solar	VA	Solar	75,000	3/4/2025	3/3/2045

(1) In operation as of December 31, 2022; generating facilities that have contracted directly with the Company

(2) PPA is for excess energy only typically 4,000-14,000 kW.

(3) PPA is for excess energy only typically 3,500 kW.

Appendix 3B-10 - Potential Unit Retirements

Company Name: Virginia Electric and Power Company **Schedule 19**

UNIT PERFORMANCE DATA

Planned Unit Retirements(1)

Unit Name	Location	Unit Type	Primary Fuel Type	Projected Retirement Year	MW Summer	MW Winter
Chesapeake CT 1	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2027**	**39**	**53**
Chesapeake GT1					15	
Chesapeake GT4					12	
Chesapeake GT6					12	
Gravel Neck 1	**Surry, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2027**	**28**	**43**
Gravel Neck CT1					14	
Gravel Neck CT2					14	
Lowmoor CT	**Covington, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2027**	**48**	**65**
Lowmoor GT1					12	
Lowmoor GT2					12	
Lowmoor GT3					12	
Lowmoor GT4					12	
Mount Storm CT	**Mt. Storm, WV**	**CombustionTurbine**	**Light Fuel Oil**	**2027**	**11**	**16**
Mt. Storm GT1					11	
Northern Neck CT	**Warsaw, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2027**	**47**	**66**
Northern Neck GT1					12	
Northern Neck GT2					11	
Northern Neck GT3					12	
Northern Neck GT4					12	
Possum Point CT	**Dumfries, VA**	**Steam-Cycle**	**Light Fuel Oil**	**2027**	**72**	**93**
Possum Point CT1					12	
Possum Point CT2					12	
Possum Point CT3					12	
Possum Point CT4					12	
Possum Point CT5					12	
Possum Point CT6					12	

(1) Reflects retirement assumptions used for planning purposes, not firm Company commitments.

Appendix 3B-11 – Planned Changes to Existing Generation Units

Company Name: ______________ **Schedule 13**

UNIT PERFORMANCE DATA[(1)(2)]

Unit Size (MW) Uprate and Derate

Unit Name	2022 (ACTUAL)	2023	2024	2025	2026	2027	2028	2029	2030 (PROJECTED)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Altavista Biomass 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell Biomass 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton Biomass 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	(1.10)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia City	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gaston Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Rapids Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden CC	-	-	-	-	-	-	54.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick County CC	-	-	23.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 8 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 2 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Greensville CC	-	-	-	64.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6 CC	-	-	-	-	-	-	-	88.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warren County CC	7.0		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	-	-	-	-	-	-	-	15.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	-	-	-	-	-	-	14.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3	-	-	-	-	-	-	16.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	-	-	-	-	-	-	13.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	10.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	-	-	-	-	-	-	-	8.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	-	-	-	-	-	-	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	-	-	-	-	-	-	13.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	-	-	-	-	-	-	-	10.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-).
(2) No Solar or Battery units have expected changes during the planning period.

Appendix 3C-1 – Generation Under Construction

Company Name: Virginia Electric and Power Company **Schedule 15a**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Annual Firm[2]	MW Nameplate
CVOW - Phase 1 (2587MW)	VA	Intermittent	Wind	2026	915	2,587
Dulles Tied Solar	VA	Intermittent	Solar	2026	6	100
Sweet Sue Solar	VA	Intermittent	Solar	2028	4	75
Walnut Solar	VA	Intermittent	Solar	2027	8	150
Winterpock Solar	VA	Intermittent	Solar	2026	1	20
Bridleton Solar	VA	Intermittent	Solar	2027	1	20
Cerulean Solar	VA	Intermittent	Solar	2026	3	62
Courthouse Solar	VA	Intermittent	Solar	2031	9	167
Ivy Landfill Distributed	VA	Intermittent	Solar	2026	0.2	3
Racefield Distributed	VA	Intermittent	Solar	2026	0.2	3
Kings Creek Solar	VA	Intermittent	Solar	2027	1	20
Southern VA Solar	VA	Intermittent	Solar	2027	7	125
Moon Corner Solar	VA	Intermittent	Solar	2026	3	60
North Ridge Solar	VA	Intermittent	Solar	2026	1	20
Beldale Solar	VA	Intermittent	Solar	2027	3	57
Blue Ridge Solar	VA	Intermittent	Solar	2027	5	95
Bookers Mill Solar	VA	Intermittent	Solar	2025	7	127
Michaux Solar	VA	Intermittent	Solar	2028	3	50
Clover Creek Solar	VA	Intermittent	Solar	2027	5	90
Hopewell Solar	VA	Intermittent	Solar	2029	7	130
Shands Storage	VA	Peak	Grid	2030	5	16

(1) Commercial Operation Date

(2) Solar firm based on average ELCC value

Appendix 3C-2 – Planned Generation Under Development

Company Name: Virginia Electric and Power Company **Schedule 15c**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Nameplate
CE-6 Solar	VA	Intermittent	Solar	2030	22.3	402
CE-6 Solar	VA	Intermittent	Solar	2031	14.2	313
CE-6 Distributed Solar	VA	Intermittent	Solar	2028	2.4	6.8
Storage	VA	Peak	Grid	2029	47.12	155
Combustion Turbines	VA	Peak	Gas	2030	756	960

(1) Estimated commercial operation date.

Appendix 3D: Demand-Side Management

Dominion Energy offers energy conservation programs designed to assist our Virginia and North Carolina electric customers with saving energy and money. We advocate for cost-effective energy efficiency innovation in residences and businesses and develop demand-side management programs to support state and national policies focused on energy conservation and the goals around energy savings. The Company seeks to empower customers by providing them with the necessary information and solutions to manage their own energy use. Over the past 16 years, Dominion Energy's programs have produced significant environmental benefits while providing customers with substantial energy savings that help lower monthly energy expenses.

This appendix provides a description of the DSM planning process, and an overview of active and rejected DSM programs.

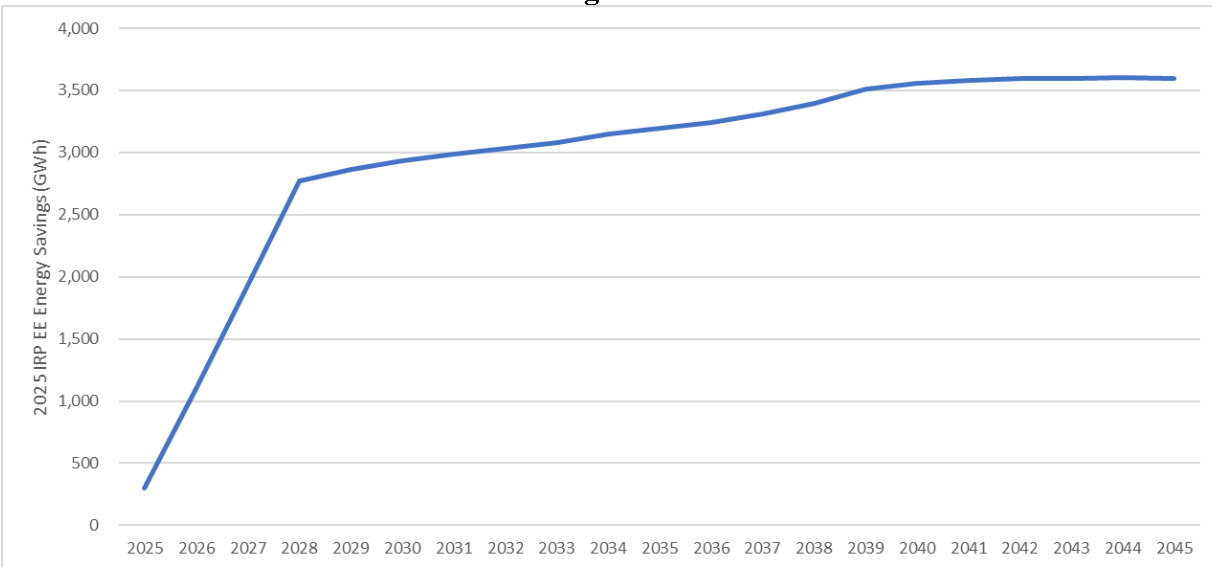
As noted in Appendix 2A in the 2024 IRP, from a modeling perspective the Company accounted for savings from its active DSM programs along with forecasted growth to those programs as a downward adjustment to the load forecast. There are several drivers that affect the Company's ability to achieve energy and demand savings from DSM, including the cost-effectiveness of programs and measures and customers' willingness to participate in active DSM programs.

To develop the energy and capacity reductions used in the primary Portfolios, the Company used the energy efficiency savings targets established in Case No. PUR-2023-00227 for 2026-2028 and continued these targets throughout the remaining 20-year planning horizon.

For 2025, the Company used the savings it expects to achieve from its active DSM programs without any adjustment. This is because all programs capable of delivering savings in 2025 must have already been approved by the VSCC in order to operate during that year. The VSCC's most recent approval, issued on August 13, 2025, of DSM Programs was in Case No. PUR-2024-00222. All new programs and measures approved therein will be available to customers at the beginning of 2026 and have been included in the forecasted savings in this 2025 IRP Update. Any future DSM programs or measures capable of delivering incremental savings would not be available until 2027 at the earliest, pending regulatory approval.

The Company's 2025 IRP Update DSM adjustment is ambitious, with forecasted incremental energy savings growing from 302 GWh in 2025 to 2,931 GWh by 2030, and over 3,500 GWh by 2045.

Figure 1

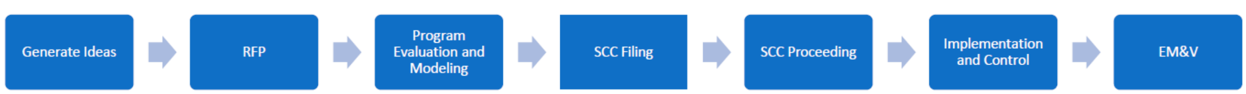


All savings are calculated on a net basis, meaning savings from "free riders"—customers that participate and receive an incentive through a utility-sponsored DSM program but who would have taken the action to achieve savings even absent the incentive—are removed from the calculation. Said another way, only savings from customers actually incented by the DSM program to make an efficient change are counted.

Achieving the forecasted level of energy savings will require diligence and cooperation among the Company and the many stakeholders who participate in the on-going DSM specific stakeholder process established by the Grid Transformation and Security Act of 2018 ("GTSA"). The remainder of this appendix will discuss the DSM planning process and stakeholder group, the DSM long-term plan, and additional specific analysis required by the GTSA.

I. DSM Planning Process

The Company has historically used the following process related to its DSM programs:



The GTSA established an independent moderator-led DSM stakeholder group, which helps to generate new program ideas. That stakeholder group meets a minimum of four times a year as a large group, with additional more frequent meetings by subgroups dedicated to specific topics of interest such as low-income specific programming or EM&V.

The Company takes stakeholder generated ideas and develops them into more concrete program parameters, which are then compiled into an RFP of candidate program designs and implementation services, which is sent annually to qualified vendors. The Company develops assumptions for new DSM programs by engaging vendors through a competitive RFP process to submit proposals for candidate program design and implementation services. As part of the bid process, basic program design parameters and descriptions of candidate programs are requested. To the extent practical, the Company prefers that the program design vendor is the same vendor that implements the final implementation. The Company believes this enables as much continuity as possible from design to implementation.

Once proposals through an RFP process are received, the Company's energy conservation group works with the Company's supply chain group to systematically review the proposals. Program designs are reviewed for responsiveness to the RFP, practicality of the design, technology requirements, staffing plan, marketing plan, reasonableness of the measures proposed, overlap with existing measures, cost reasonableness, previous experience, work history with the Company, expected ability to deliver the services proposed, and ability of the proposing firm to comply with the Company's terms and conditions, data protection requirements, and financial requirements. Proposals must contain detailed information regarding measure load profiles and market penetration projections in a specific format which allows modeling of the program as a demand-side resource when compared against other resources, including supply-side resources.

Candidate designs that are judged to be reasonable, based on preliminary review, are evaluated for cost-effectiveness from a multi-perspective approach using four of the standard tests from the California Standard Practice Manual: (i) the Participant Test, (ii) Utility Cost Test, (iii) Total Resource Cost Test, and (iv) Ratepayer Impact Measure Test. Each test uses the NPV of costs and benefits. Tests are conducted at a program and portfolio level.

The Company has developed the Load Management Tool (LMT) to perform the cost/benefits test leveraging avoided cost benefits obtained from the Company's most recent IRP. The Company reviews the results of all four of the NPV cost/benefit test scores to evaluate whether to file for regulatory approval of a particular potential program, extension, or modification.

If the programs are cost-effective based on the modeling results, or otherwise legislatively stated to be in the public interest, the programs are filed with the VSCC for approval. The VSCC approval process lasts approximately eight months. For the programs that are active, the Company works with the RFP suppliers to finalize a contract for full implementation of the program. Once all details are finalized, a new DSM program can be launched for participation by eligible customers. Programs that meet the statutory criteria in Virginia are then, when feasible on a smaller scale, brought forth in the following year to the NCUC for consideration.

Finally, the Company conducts evaluation, measurement and verification ("EM&V") of all active DSM programs and files the annual EM&V report with the VSCC and NCUC in June of each year. Results are shown for the prior calendar year on specific metrics, including program participation, spending, energy, and demand savings. Based on stakeholder feedback, these EM&V filings also include a "dashboard" of metrics most of interest to stakeholders. Some highlights from 2024 include:

Figure 2[1]

II. Active DSM Programs and Incremental Savings

Appendix 3E provides program descriptions for the currently active DSM programs. Included in the descriptions are the branded names used for customer communications and marketing plans that the Company is employing and its plans to achieve each program's penetration goals.

In addition to the active DSM programs, on December 13, 2024, the Company filed for SCC approval in Case No. PUR-2024-00222 for Phase XIII DSM programs, which includes energy efficiency (EE) and demand response (DR) Programs:

- Residential Smart Thermostat (DR)
- Non-residential Small Business Improvement (EE)
- Non-residential Data Center (EE)
- Non-residential Enhanced Prescriptive (EE)
- Non-residental Curtailment (DR)
- Non-residential Distributed Generation (DR)
- Residential Battery Storage Pilot (DR)

The SCC issued its Final Order in Case No. PUR-2024-00222 on August 13, 2025, approving all programs with the exception for the Residential Battery Storage Pilot (DR).

Appendix 3F provides program descriptions for these recently approved DSM programs.

[1] 2024 Evaluation, Measurement and Verification Report as filed in *Application of Virginia Electric and Power Company for approval of its 2023 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUR-2023-00217 (June 16, 2025).

III. Rejected DSM Programs

A list of the rejected DSM programs from prior integrated resource planning cycles is shown in Appendix 3H of the 2024 IRP. These are DSM programs that were not found to be cost-effective when modeled during a particular planning cycle. Rejected programs may be re-evaluated and included in future DSM portfolios.

IV. GTSA Energy Efficiency Analysis

Enactment Clause 18 of the GTSA required, "That as part of its integrated resource plans filed between 2019 and 2028, any Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, shall incorporate into its long-term plan for energy efficiency measures policy goals of reduction in customer bills, particularly for low-income, elderly, veterans, and disabled customers; reduction in emissions; and reduction in the utility's carbon intensity."

In its 2021 DSM filing, Case No. PUR-2021-00247, the Company filed a long-term plan for the Company's DSM initiatives with the goal of setting forth an achievable strategy for meeting the VCEA energy efficiency targets, as well as the state energy and policy goals noted above. The long-term plan provides a vision and pathways for making every practicable effort to achieve the legislative goals over short-, medium-, and long-term time frames. The long-erm plan addresses: (i) strategic vision; (ii) achievability of GTSA and VCEA energy efficiency goals; (iii) risks, challenges, and opportunities stemming from legislative and regulatory changes; (iv) sector profiles, program design recommendations, and implementation pathways aligned with goals and high-level timelines; (v) approaches for adapting to an evolving customer market and advancements in technology; and (vi) high level forecast of energy and demand impacts, program costs, and cost-effectiveness.

The Company immediately began addressing the recommendations contained within the long-term plan and has made proposals to the SCC consistent with the recommendations therein as part of its filings for DSM in 2021-2023. The Company has made considerable progress since the implementation of a portfolio marketing strategy aimed at increasing overall awareness of its DSM programs and benefits of adopting energy conservation technologies and behaviors.

In particular, the Company notes that as part of its long-term plan for energy efficiency measures, the Company has projected spending at least 15% of all DSM-related spending on programs targeted towards low-income, elderly, and veteran populations. The Company's current DSM portfolio inclusive of the recently approved DSM programs includes 13.7% of all DSM program costs designed to benefit vulnerable customers.

The continued implementation of the active DSM programs will further carbon intensity reduction goals, reduce the number of RECs required for RPS compliance, and benefit participating customers through lower energy usage and resulting bills. The Company will continue to actively participate in the stakeholder forum, which provides transparency and inclusivity in the DSM planning process as part of its efforts to achieve the DSM policy goals set by the Commonwealth.

Enactment Clause 18 of the GTSA also directed that utility considerations of energy efficiency within its long-term plan shall include analysis of the following:

- Energy efficiency programs for low-income customers in alignment with billing and credit practices;
- Energy efficiency programs that reflect policies and regulations related to customers with serious medical conditions;
- Programs specifically focused on low-income customers, occupants of multifamily housing, veterans, elderly, and disabled customers;
- Options for combining distributed generation, energy storage, and energy efficiency for residential and small business customers;
- The extent that electricity rates account for the amount of customer electricity bills in the Commonwealth and how such extent in the Commonwealth compares with such extent in other states, including a comparison of the average retail electricity price per kWh by rate class among all 50 states;
- An analysis of each state's primary fuel sources for electricity generation, accounting for energy efficiency, heating source, cooling load, housing size, and other relevant factors; and
- Other issues as seem appropriate.

These items are addressed in the subsequent sections.

Considerations for Certain Customers Groups and Options for Combining Distributed Generation, Energy Storage, and Energy Efficiency

The Company's Residential Income and Age Qualifying Home Improvement Bundle Program provides in-home energy assessments and installation of select energy-saving products at no cost to eligible participants. Additionally, the Company offers certain EnergyStar measures such as EnergyStar appliances, EnergyStar ceiling fans, and EnergyStar windows to low-income customers.

The bundled version of its income and age qualifying programs was designed to ensure differing program offerings did not expire and to promote greater operational efficiencies with the Weatherization Service Provider ("WSP") network in the field, which consists of non-profit providers performing the program field work and installing select energy-saving program measures. The Program is available to qualified customers in the Company's Virginia service territory who earn 60% state median or area median income, whichever is higher. It is also available to customers who are 60 years or older with a household income of 120% of the state or area median income. The Program is available to qualified individuals living in single-family homes, multifamily homes, and mobile homes.

The House Bill 2789 solar component available to eligible customers through December 31, 2024, offers incentives to participants of the first component for the installation of photovoltaic solar panels at their residence upon completion of HVAC energy efficiency house improvements. As with the Company's other low-income programs, the Company partners with WSPs to perform community outreach and install program measures to eligible customers.

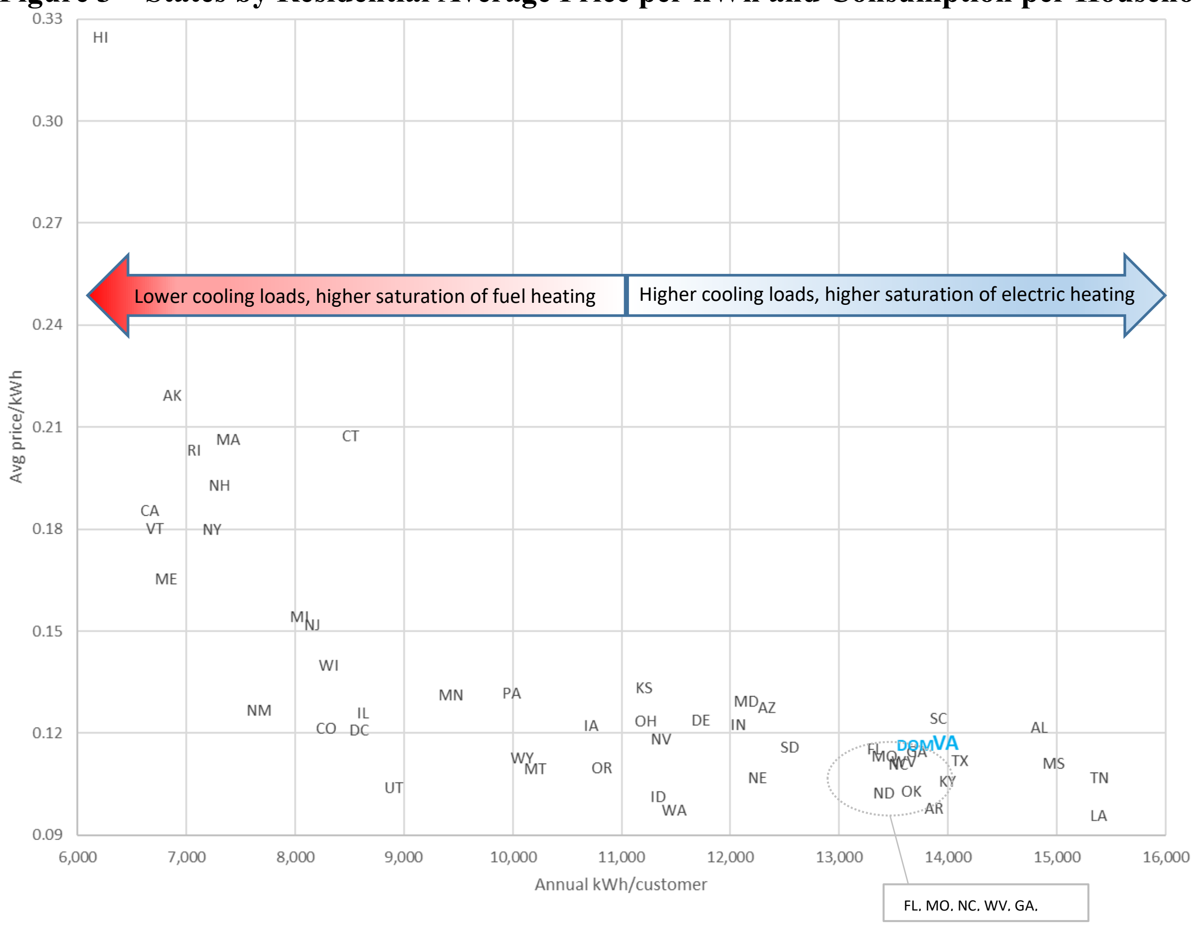
Separate from program proposals, a special subgroup focused on low-income DSM program improvements meets as part of the stakeholder process and making valued suggestions for future program improvements that will result in better alignment with the state's federally funded program. The Company has and will continue to work with the Department of Housing and Community Development to establish alignment with programs where helpful and beneficial.

<u>Electricity Rate and Consumption Comparison</u>

Electricity bills are driven by a combination of electricity rates and electricity consumption. The following charts show where each state and the Company falls by electricity rate and consumption.

In the residential sector, the Company and Virginia as a whole fall within a cluster of mostly southern states with below-average rates and relatively high consumption. The consumption level reflects a high saturation of electric heating equipment compared to other parts of the U.S., paired with high cooling loads.

Figure 3 – States by Residential Average Price per kWh and Consumption per Household



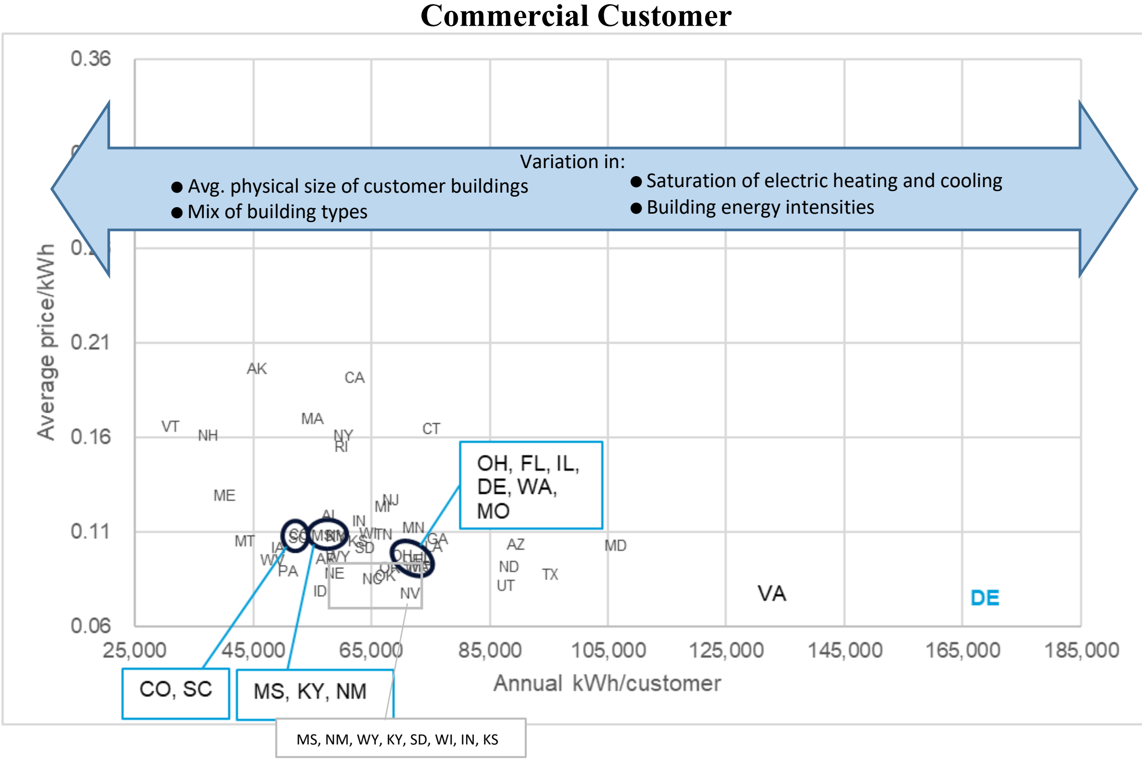
Notes: U.S. Energy Information Administration. Table 5A, Residential Average Monthly Bill by Census Division, and State (Annualized), https://www.eia.gov/electricity/sales_revenue_price/.

U.S Energy Information Administration, Annual Electric Power Industry Report, Form EIA-861 detailed data files, Year: 2021, https://www.eia.gov/electricity/data/eia861/.

In the commercial sector, Virginia is an extreme outlier in consumption per customer, averaging more than 130,000 kWh per year. The Company is one of three utilities in Virginia with average commercial consumption over 100,000 kWh per year; the others are the City of Harrisonburg, Appalachian Power Co., and Virginia Tech Electrical Services. In contrast, the utility with the lowest average commercial consumption is Northern Neck Elec Coop, Inc with less than 16,000 kWh per commercial customer.

The primary drivers of commercial consumption are the size of the customer (*i.e.*, building square feet, number of employees) and the type of building activity. Denser urban areas tend to have larger commercial buildings and therefore higher average commercial consumption, and the Company's service territory captures many of Virginia's densest urban areas. The Company also has a high concentration of data centers among its commercial customers. Data centers are extremely energy intensive, as the densely packed computing equipment they contain produces waste heat that drives high space cooling loads. Because of the extreme differences among commercial customers, building efficiencies are typically compared based on energy intensity (*i.e.*, energy use per square foot) and only among similar building types (*i.e.*, offices with offices and restaurants with restaurants). Unfortunately, data was not available to calculate energy intensity for each state, or to make more granular comparisons.

Figure 4 – States by Average Commercial Price per kWh and Average Consumption per Commercial Customer



Note: U.S. Energy Information Administration. Table 5B. Commercial Average Monthly Bill by Census Division, and State (Annualized). https://www.eia.gov/electricity/sales_revenue_price/.

National Comparison of Primary Fuel Sources for Generation

The Company engaged DNV to analyze fuel source for generation, as well as the additional metrics referred to in the legislation. This analysis is provided in Appendix 3J in the 2024 IRP.

Other Relevant Issues for Energy Efficiency Analysis

The Company's Proposed Energy Efficiency Savings Targets Report, filed with the VSCC in Case No. PUR-2023-00227, provides a robust discussion of other relevant issues for energy efficiency analysis, including the principles of feasibility and achievability, legislative and regulatory requirements in the Commonwealth of Virginia, experience from historical programs, the availability and achievability of programmatic energy efficiency savings in the market; and the Company's actual experience administering DSM programs. Appended thereto is the most recent Energy Efficiency Potential Study, conducted by DNV, which assessed the potential for electric energy (kWh) and demand (kW) savings from company-sponsored demand side management (DSM) programs over 10 years starting in 2024 for Dominion Energy's Virginia service territory. The findings from this study heavily influenced the Company's DSM adjustment as used in this 2024 IRP.

Appendix 3E: Description of Active DSM Programs

Non-Residential Distributed Generation Program

Branded Name: Distributed Generation
State: Virginia
Target Class: Non-Residential
VA Program Type: Demand-Side Management
VA Duration: 2012 – 2045

Program Description:
As part of this Program, a third-party contractor will dispatch, monitor, maintain and operate customer-owned generation when called upon by the Company at anytime for up to a total of 120 hours per year. The Company will supervise and implement the Non-Residential Distributed Generation Program through the third-party implementation contractor. Participating customers will receive an incentive in exchange for their agreement to reduce electrical load on the Company's system when called upon to do so by the Company. The incentive is based upon the amount of load curtailment delivered during control events. When not being dispatched by the Company, the generators may be used at the participants' discretion or to supply power during an outage, consistent with applicable environmental restrictions.

Program Marketing:
Marketing is handled by the Company's implementation vendor.

Residential Smart Thermostat Program (DR)

Target Class: Residential
VA Program Type: Demand Response
NC Program Type: Demand Response
VA Duration: Re-Proposed
NC Duration: Future

Program Description:

All residential customers who are not already participating in the Company's DSM Phase I Smart Cooling Rewards Program and who have a qualifying smart thermostat would be offered the opportunity to enroll in the peak demand response portion of the Program. Demand Response will be called by the Company during times of peak system demand throughout the year and thermostats of participating customers would be gradually adjusted to achieve a specified amount of load reduction while maintaining reasonable customer comfort and allowing customers to opt-out of specific events if they choose to do so.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Smart Thermostat Program (EE)

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Re-Proposed
NC Duration:	Future

Program Description:

This Program provides an incentive to customers to either purchase a qualifying smart thermostat and/or enroll in an energy efficiency program, which helps customers manage their daily heating and cooling energy usage by allowing remote optimization of their thermostat operation, and provides specific recommendations by e-mail or letter that customers can act on to realize additional energy savings. The Program is open to several thermostat manufacturers, makes, and models that meet or exceed the Energy Star requirements and have communicating technology. Rebates for the purchase of a smart thermostat are provided on a one-time basis; incentives for participation in remote thermostat management are provided on an annual basis. For those customers who are enrolled in thermostat management, additional energy-saving suggestions based on operational data specific to the customer's heating and cooling system are provided to the customer at least quarterly.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Electric Vehicle (EE/DR) Program

Target Class:	Residential
VA Program Type:	Energy Efficiency/ Demand Response
NC Program Type:	Energy Efficiency/Demand Response
VA Duration:	2021 – 2045
NC Duration:	Future

Program Description:
This Program provides qualifying residential customers with an incentive to to purchase a Level 2 charger for their electric vehicle and who agree to enroll in the demand response ("DR") component of the proposed program. Demand response would be called by the Company during times of peak system demand throughout the year to reduce the electric vehicle charging load while encouraging customers

to charge their vehicles during off-peak hours. Customers can opt-out of specific events if they choose to do so.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Electric Vehicle Peak Shaving Program

Target Class:	Residential
VA Program Type:	Peak-shaving
NC Program Type:	Peak-shaving
VA Duration:	2021 – 2045
NC Duration:	Future

Program Description:
This Program provides an incentive for residential customers who already have a qualifying Level 2 charger and wish to participate in the demand response component only (no purchase incentive).

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Electric Vehicle (EE/DR) Program

Target Class:	Residential
VA Program Type:	Energy Efficiency/ Demand Response
NC Program Type:	Energy Efficiency/Demand Response
VA Duration:	2021 – 2045
NC Duration:	Future

Program Description:
This Program provides qualifying residential customers with an incentive to purchase a Level 2 charger for their electric vehicle and who agree to enroll in the demand response ("DR") component of the proposed program. Demand response would be called by the Company during times of peak system demand throughout the year to reduce the electric vehicle charging load while encouraging customers to charge their vehicles during off-peak hours. Customers can opt-out of specific events if they choose to do so.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Energy Efficiency Kits Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2021 – 2045
NC Duration:	Future

Program Description:
This Program provides qualifying residential customers with customers with new customer accounts the opportunity to receive Welcome Kits. The Welcome kit will initially include a Tier 1 advanced power strip and an educational insert informing customers about opportunities to manage their energy use and how to opt into receiving additional free measures by going online to the program website or calling the program hotline. To receive the additional measures, customers will have to confirm their address and account status and answer a few questions to confirm the measures will be of value in producing electric energy savings in the home. Additionally, customers will receive educational materials on proper use of each measure, energy use in general, and energy savings available through other Company DSM programs.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Home Retrofit Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2021 – 2045
NC Duration:	2022-2045

Program Description:
This Program targets high users of electricity with an incentive to conduct a comprehensive and deep whole house diagnostic home energy assessment.

The proposed program re-design incorporates key program measures from the Company's Phase VII Residential Home Energy Assessment Program into the Phase VIII Residential Home Retrofit Program Bundle. A-line LEDs are not included in the program redesign in response to recent EISA-driven changes to baseline efficiency. Program design introduces a handful of select new measures including the replacement of Electric Baseboard Heating with Air Source Heat Pump, High Efficiency Room AC Upgrades, and Shower Thermostats.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Manufactured Housing Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2021 – 2045
NC Duration:	Future

Program Description:
This Program provide residential customers in manufactured housing with educational assistance and an incentive to install energy efficiency measures.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential/Non-residential Multifamily Program

Target Class:	Residential /Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2021 – 2045
NC Duration:	Future

Program Description:
The Multifamily Program is designed to encourage investment in both residential and commercial service aspects of multifamily properties. The Program design is based on a whole building approach where the implementation vendor will identify as many cost-effective measure opportunities as possible in the entire building (both residential and commercial meter) and encourage property owners to address the measures as a bundle. This approach provides one-stop-shop programming for multifamily property owners with solutions to include direct install-in-unit measures and incentives for prescriptive efficiency improvements. The Program will identify, track and report residential (in-unit) and commercial (common space) savings separately according to the account type.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Non-Residential Midstream EE Products Program

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2021 – 2045
NC Duration: Future

Program Description:
This Program consists of enrolling equipment distributors into the Program through an agreement to provide point-of-sales data in an agreed upon format each month. These monthly data sets will contain, at minimum, the data necessary to validate and quantify the eligible equipment that has been delivered for sale in the Company's service territory. In exchange for the data sets, the distributor will discount the rebate-eligible items sold to end customers. This Program aims to increase the availability and uptake of efficient equipment for the Company's non-residential customers.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Small Business Improvement Enhanced

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2021 – 2045
NC Duration: Future

Program Description:
This Program provides small businesses an energy use assessment and tune-up or re-commissioning of electric heating and cooling systems, along with financial incentives for the installation of specific energy efficiency measures. Participating small businesses would be required to meet certain size and connected load requirements.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Residential Smart Home Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2022 – 2045
NC Duration:	2023-2045

Program Description:
This Program provides the Company's residential customers a suite of smart home products that provide seamless integration in the home. The program will deliver the energy efficient measures bundled in two versions of a Smart Home Kit, so that customers can benefit from a fully integrated set of compatible smart products.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Virtual Audit Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2022 – 2045
NC Duration:	2023-2045

Program Description:
This Program offers residential customers a self-directed home energy assessment using an audit software, completed entirely by the customer, with no trade ally entering the home. Customers would be directed to a website or toll-free number where they would answer a set of questions with answers specific to the conditions and systems in their home with aids to help them answer accurately.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Water Savings (EE) Program

Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2022 – 2045
NC Duration: Future

Program Description:
Program is designed to give the Company's residential customers control over their water related energy use. The proposed Program leverages the installation of smart communicating water heating and pool pump technologies to facilitate more efficient operation while reducing overall electricity usage and peak demand response. Customers have the option to purchase a qualified program product online, in-store, equipment distributor, or through qualified local trade allies.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Water Savings (Demand Response) Program

Target Class: Residential
VA Program Type: Demand Response
NC Program Type: Demand Response
VA Duration: 2022 – 2045
NC Duration: Future

Program Description:
All residential customers who purchase and install a qualified product (EE component) will be offered the opportunity to enroll in the peak demand reduction (DR) component of the DR Program. Additionally, customers who have previously purchased a qualifying product and who have the eligible products installed, will be offered the opportunity to enroll in the DR component of the Program. Customers would be allowed to opt-out of a certain number of events.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Non-Residential Agricultural Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2022 – 2045
NC Duration:	Future

Program Description:
This Program provides qualifying non-residential customers with incentives to implement specific energy efficiency measures to help agribusinesses replace aging, inefficient equipment and systems with new, energy-efficient technologies. The Program is designed to help agricultural customers make their operations more energy-efficient by providing incentives for efficient agricultural equipment and lighting specifically used in agricultural applications.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Non-Residential Building Automation

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2022 – 2045
NC Duration:	Future

Program Description:
This Program provides qualifying non-residential customers with incentives to install new building automation systems in facilities that do not have centralized controls or have an antiquated system that requires full replacement.

Program Marketing:
Marketing is handled by the Company’s implementation vendor.

Non-Residential Building Optimization

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency

NC Program Type: Energy Efficiency
VA Duration: 2022 – 2045
NC Duration: Future

Program Description:
This Program provides qualifying non-residential customers with incentives for the installation of energy efficiency improvement, consisting of recommissioning measures. The Program seeks to capture energy savings through control system audits and tune-up measures in facilities with Building Energy Management Systems.

Program Marketing:
Marketing is handled by the Company's implementation vendor.

Non-Residential Engagement Program
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2022 – 2045
NC Duration: Future

Program Description:
The Program engages commercial buildings in energy management best practices that increase awareness of operational and behavioral energy savings opportunities. The Program would educate and train businesses' facility management staff on ways to achieve energy savings through optimization of building energy performance and integrating ongoing commissioning best practices into their operations.

Program Marketing:
Marketing is handled by the Company's implementation vendor.

Non-Residential Enhanced Prescriptive Program
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2022 – 2045
NC Duration: 2022-2045

Program Description:
This Program provides qualifying non-residential customers with an incentive for the installation of

refrigeration, commercial kitchen equipment, HVAC improvements, window film installation and maintenance and installation of other program specific, energy efficiency measures.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Residential Income and Age Qualifying Home Energy Report Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2023 – 2045
NC Duration:	Future

Program Description:
This Program would offer the opportunity for low income qualifying customers to save energy in their homes while providing incentives for verified energy savings.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Small Business Behavioral Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2023 – 2045
NC Duration:	Future

Program Description:
This Program would provide small businesses with customized business energy report (BER), either digitally or through mail, with energy saving tips, forecasting, and recommendations. The proposed program design also incorporates higher touch customer engagement, which engages small business owners in a quick online experience to learn more about their energy usage, find customized ways to save energy, provide data to the program to improve energy savings personalization for each business segment and cross-promote other DSM programs in addition to connecting the customer with the program design vendor's energy advisors.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Non-Residential Data Center and Server Room Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2023 – 2045
NC Duration:	Future

Program Description:
This Program provides qualifying non-residential customers with an incentive to install energy efficiency measures related to equipment in and operation of data centers and server rooms.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Non-Residential Lighting Systems & Controls Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2023 – 2045
NC Duration:	Future

Program Description:
This Program provides qualifying non-residential customers with an incentive to implement more efficient lighting technologies that can produce verifiable savings. The Program promotes the installation of lighting technologies including but not limited to LED based bulbs and lighting control systems.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program

by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Non-Residential Health Care Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2023 – 2045
NC Duration:	Future

Program Description:
This Program provides would target the health care customer segment and will provide those qualifying non-residential customers with incentives to install energy efficiency measures.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Non-Residential Hotel and Lodging Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2023 – 2045
NC Duration:	Future

Program Description:
This Program provides would target the target the hotel and lodging customer segment and would provide those qualifying non-residential customers with incentives to install energy efficiency measures.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Voltage Optimization

Target Class:	Non-Residential/Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2023 – 2045
NC Duration:	Future

Program Description:
Voltage optimization ("VO") will reduce energy consumption for a wide cross-section of customers. Control of the program will be implemented on Dominion Energy equipment, but 98-99% of the energy reduction occurs behind the meter at the end-use loads. Customers will see benefits in reduced bills due to reductions in both energy consumption and peak demand.

Program Marketing:
Not Applicable

Residential Peak Time Rebate Program

Target Class:	Residential
VA Program Type:	Energy Efficiency/Demand Response
NC Program Type:	Energy Efficiency/Demand Response
VA Duration:	2024-2045
NC Duration:	Future

Program Description:
This Program would enable residential customers to reduce their energy usage consumption during peak time periods as called upon by the Company. During peak time rebate event days, proposed program design will alert customers with text messaging, emails or outbound telemarketing voicemail, as well as by utilizing the Company's dominionenergy.com website with banner announcements informing participants an event is in progress

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Non-Residential Custom Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2024-2045
NC Duration:	Future

Program Description:
This Program would provide qualifying non-residential customers, with a focus on larger facilities with demand greater than 300 kW, with the technical support and incentives needed to pursue non-standard, more complex energy efficiency projects. Qualifying non-residential customers develop tailored projects that best meet their unique facility and organizational goals while achieving savings from a diverse mix of measures.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Residential Electric Vehicle (EV) Pilot Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2024-2045
NC Duration:	Future

Program Description:
The proposed program pilot would run in parallel with the current Residential Electric Vehicle Demand Response Program. Instead of communicating with the electric vehicle charger, the proposed pilot program would allow for integration with newer technology onboard vehicle telematics to capture charging data and control the charging rate during load curtailment events dispatched by the Company.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Energy Efficient Products Marketplace Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2024-2045
NC Duration:	Future

Program Description:
The Program provides eligible residential customers an incentive to purchase specific energy efficient appliances with a rebate through an online marketplace and through participating retail stores.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to direct mail, bill inserts, web content, social media, and outreach events.

Residential Customer Engagement Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2024-2045
NC Duration:	Future

Program Description:
Program provides educational insights into the customer's energy consumption via a Home Energy Report (on-line and/or paper version). The Home Energy Report is intended to provide periodic suggestions on how to save energy based upon analysis of the customer's energy usage. Customers can opt-out of participating in the Program at any time.

Program Marketing:
Not applicable.

Residential Income and Age Qualifying Home Improvement Program Bundle

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2024-2045
NC Duration:	2024-2045

Program Description:
The bundled version of the Residential Income and Age Qualifying Home Improvement Program combines the Company's existing HB 2789 HVAC Program measures in addition to the Phase IX and X low-income program measures while adding several new program measures and creating a bundled income qualifying program that would provide income and age qualifying residential customers with in-home energy assessments and installation of select energy-saving measures. Energy assessments and installations will be conducted by qualified, local weatherization service providers ("WSP") who currently offer weatherization related services through the Virginia Department of Housing and Community Development and have been approved by the Income and Age Qualifying Program to complete assessments and install the selected energy-saving products.

Program Marketing:
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

Non-residential Income and Age Qualifying Home Improvement Program Bundle

Target Class:	Non-residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2024-2045
NC Duration:	2024-2045

Program Description:
Program offers installation of select energy-saving measures to be installed in properties that house low-income and aging residents, but the electric bill is paid by the property, rather than the individual resident. This would include housing authority and master metered properties, assisted living residences, and nursing homes.

Program Marketing:
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

Residential New Construction Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:
This Program would provide incentives to home builders for the construction of new homes that are ENERGY STAR certified by directly recruiting existing networks of homebuilders and Home Energy Rating System (HERS) Raters to build and inspect ENERGY STAR Certified new homes. The re-designed Residential New Construction Program will expand its existing single path offering to encourage added builder participation through a flexible entry-level approach that appropriately incentivizes builders to invest in and promote deeper energy savings. Additionally, the DSM Phase XII proposed re-design supports builders in constructing best in class above-code homes by offering a second tier to building eligibility. These two tiers consist of ENERGY STAR Version 3.1 and ENERGY STAR NextGen Tier.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Non-Residential New Construction Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:
This Program would provide qualifying non-residential customers would provide qualifying facility owners with incentives to install energy efficient measures in their new construction project. Program engineers will determine what potential energy efficiency upgrades are of interest to the owner and feasible within their budget. These measures coupled with basic facility design data will be analyzed to determine the optimized building design. This in-depth analysis will be performed using building energy simulation models, which will allow for ‘bundles’ of measures to be tested for potential energy savings gains from interactive effects. The results will be presented to the facility owner to determine which measures(s) are to be installed. The proposed program design targets three main building-type categories –commercial buildings, industrial buildings, and data centers.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Residential Smart Thermostat Purchase Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:
This Program would provide an incentive to residential customers to purchase a qualifying smart thermostat through the Company's online marketplace platform and brick and mortar participating retailers. The Program is open to several thermostat manufacturers, makes, and models that meet or exceed the Energy Star requirements and have communicating technology. Rebates for the purchase of a smart thermostat are provided on a one-time basis.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential Smart Thermostat Demand Response Program

Target Class:	Residential
VA Program Type:	Demand Response
NC Program Type:	Demand Response
VA Duration:	Proposed
NC Duration:	Future

Program Description:
The Residential Smart Thermostat (DR) Program is a peak demand response program through which demand response is called by the Company during times of peak system demand throughout the year and thermostats of participating customers would be adjusted to achieve a specified amount of load reduction while maintaining reasonable customer comfort through a gradual increase in home temperature and allowing customers to opt-out of specific events if they choose to do so. Customers receive one-time enrollment incentive and an annual incentive for participating in the program.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Appendix 3F: Description of Recently Approved DSM Programs

Non-Residential Data Center Program (EE)

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

This Program would provide qualifying non-residential customers with incentives to install energy efficiency measures related to equipment in and operation of data centers. Program services, as well as program measure installation, for this Program will be delivered through a network of qualified contractors and/or consultants with the appropriate specialization and experience to provide relevant, up-to-date advice on the measures included in the proposed program design. The new program design builds off the momentum of the existing DSM Phase X Data Center and Server Room Program while incorporating an expanded list of energy efficiency measures and funding for small, medium-sized, and larger data center customers. The proposed program design measure list includes computer and power distribution equipment, HVAC, lighting, controls, and whole-building analysis options.

Program Marketing:

The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Non-Residential Small Business Improvement Program (EE)

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:

The proposed program design offers a comprehensive and flexible approach that includes an energy use assessment to identify and prioritize energy-saving opportunities for qualifying small business customers along with financial incentives for the installation of specific energy efficiency measures.,

Program Marketing:

The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Non-Residential Enhanced Prescriptive Program (EE)

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Proposed
NC Duration:	Future

Program Description:
The proposed program would provide qualifying non-residential customers with incentives for the installation of refrigeration, commercial kitchen equipment, HVAC improvements, window film installation and maintenance and installation of other program specific, energy efficiency measures.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because this program is implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Residential Smart Thermostat Demand Response Program (DR)

Target Class:	Residential
VA Program Type:	Demand Response
NC Program Type:	Demand Response
VA Duration:	Proposed
NC Duration:	Future

Program Description:
The Residential Smart Thermostat (DR) Program is a peak demand response program through which demand response is called by the Company during times of peak system demand throughout the year and thermostats of participating customers would be adjusted to achieve a specified amount of load reduction while maintaining reasonable customer comfort through a gradual increase in home temperature and allowing customers to opt-out of specific events if they choose to do so. Customers receive one-time enrollment incentive and an annual incentive for participating in the program.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Non-Residential Curtailment Demand Response (DR)

Target Class:	Non-Residential
VA Program Type:	Demand Response
NC Program Type:	Demand Response
VA Duration:	Proposed
NC Duration:	Future

Program Description:
The proposed program design targets medium sized and large commercial and industrial (C&I) customers to curtail their energy usage using manual load curtailment during times of peak system demand. Each participating customer (facility) will have a curtailment plan developed, also known as a load reduction plan (LRP), which is specific to the facility and guided by engineering assessments put together by the program implementation vendor in collaboration with facility staff, factoring in the opportunity cost of participation, facility equipment and operations, and staff availability.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Non-Residential Distributed Generation Program (DR)

Target Class:	Non-Residential
VA Program Type:	Demand Response
NC Program Type:	Demand Response
VA Duration:	Proposed
NC Duration:	Future

Program Description:
The Program would provide qualifying customers with an incentive to curtail load by operating backup generation upon request. The Program is implemented by a contractor who is responsible for enabling remote operation and monitoring the customer's power generators, and for dispatching load during curtailment events under the direction of the Company. The program will provide participating customers a monthly incentive to allow their on-site backup generators to be remotely activated by the program implementation vendor during load curtailment events.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Appendix 4A: Virginia Bill Analysis

The Company calculated projected bills for each customer class under each Primary Portfolio using two methodologies: (1) based on requirements set by the Virginia State Corporation Commission ("SCC") ("Directed Methodology"); and (2) using a forecasted system and class sales growth and the associated class allocation factors ("Company Methodology"). The Directed Methodology requires the Company use constant class allocation factors across time and no sales growth, either at the system or class level, in its calculations. As discussed in prior IRP proceedings, the Company believes that this methodology overstates bill projections for the residential customer class because it does not reflect anticipated growth in sales, which is not expected to be uniform between classes, and shifts cost allocation as a result.

It is not a plausible assumption that class allocation factors will remain constant or that there will be no sales growth. Changes in sales growth naturally alter the proportion of sales to each class and, thus, the costs allocated to each class. Notably, the proportion of costs allocated to the residential class is projected to decrease over time because of growth of energy sales to other customer classes. The past five years demonstrate not only that sales growth will continue but also that it will be different amongst classes.

Given these concerns with the Directed Methodology, the Company has also calculated projected bills under each primary Portfolio using forecasted system and class sales growth and the associated class allocation factors. This methodology is referred to as the Company Methodology.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - COMPANY PREFERRED PLAN,
COMPANY METHODOLOGY

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 60.93	$ 60.93	$ 60.71	$ 60.71	$ 73.57	$ 75.80	$ 77.97	$ 79.06	$ 79.57	$ 80.93	$ 81.21
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (0.47)	$ (0.43)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	$ 12.91	$ 15.58	$ 19.40	$ 21.49	$ 23.43	$ 27.67	$ 30.49	$ 33.10	$ 35.31	$ 36.77	$ 37.90
FUEL - RIDER A	$ 23.25	$ 17.36	$ 17.02	$ 20.45	$ 35.38	$ 28.59	$ 20.74	$ 29.68	$ 35.10	$ 33.03	$ 32.37	$ 33.31	$ 35.92	$ 38.17	$ 40.17
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.37	$ 2.91	$ 3.05	$ 2.97	$ 2.83	$ 2.76	$ 2.46	$ -	$ -
DSM	$ 1.13	$ 1.13	$ 1.47	$ 1.31	$ 1.60	$ 1.84	$ 1.55	$ 1.57	$ 2.04	$ 2.22	$ 2.27	$ 2.22	$ 2.17	$ 2.11	$ 2.01
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 0.03	$ 0.03	$ 0.73	$ -	$ -	$ 0.26	$ 0.26	$ 0.25	$ 0.25	$ 0.24	$ 0.24	$ 0.23
Generation Infrastructure															
GENERATION RIDERS [2]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	$ 14.51	$ 6.67	$ 6.57	$ 7.57	$ 5.10	$ 5.87	$ 5.88	$ 6.02	$ 5.89	$ 5.50	$ 5.28
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 2.07	$ 0.93	$ 1.29	$ 3.48	$ 3.82	$ 3.73	$ 4.46	$ 5.25	$ 6.15	$ 6.59	$ 6.58
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.59	$ 1.07	$ 1.46	$ 2.02	$ 2.44	$ 2.31	$ 2.17
Distribution Infrastructure [3]															
DISTRIBUTION RIDERS	$ 1.84	$ 1.40	$ 1.40	$ 2.16	$ 3.84	$ 2.53	$ 7.81	$ 6.77	$ 9.04	$ 10.00	$ 10.95	$ 11.55	$ 12.19	$ 11.28	$ 10.87
A5 Environmental															
RIDER E [4]	$ 1.99	$ 1.99	$ 1.67	$ 1.25	$ 1.95	$ 2.03	$ 1.35	$ 0.64	$ 0.57	$ 0.67	$ 1.06	$ 1.18	$ 1.48	$ 1.40	$ 1.22
RIDER CCR	$ -	$ -	$ -	$ 2.95	$ 2.96	$ 2.38	$ 1.18	$ 1.18	$ 1.82	$ 2.38	$ 2.28	$ 2.19	$ 2.08	$ 1.98	$ 1.88
RIDER RGGI	$ -	$ -	$ -	$ 2.39	$ -	$ 4.43	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources															
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.00	$ 5.00	$ 6.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.19	$ 3.47	$ 5.92	$ 8.63	$ 11.68	$ 14.90
RPS Program-Related Resources															
RIDER RPS [5]	$ -	$ -	$ -	$ 0.18	$ 1.81	$ 1.32	$ 4.69	$ 7.68	$ 5.64	$ 6.59	$ 8.02	$ 8.02	$ 8.23	$ 8.26	$ 7.80
RIDER CE [6]	$ -	$ -	$ -	$ 0.19	$ 1.67	$ 2.59	$ 4.10	$ 6.17	$ 10.61	$ 12.09	$ 14.76	$ 17.65	$ 23.25	$ 27.81	$ 30.91
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.38)	$ (1.15)	$ (1.22)	$ (1.55)	$ (2.33)	$ (3.04)	$ (3.72)	$ (3.78)	$ (5.37)	$ (7.58)	$ (9.74)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.02)	$ (0.68)	$ (1.35)	$ (2.02)	$ (2.07)	$ (2.84)	$ (3.18)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.03)	$ (0.03)	$ -	$ (0.96)	$ (0.38)	$ (0.36)	$ (0.81)	$ (1.13)	$ (1.22)	$ (1.28)	$ (1.34)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 1.26**	**$ 1.41**	**$ 2.89**	**$ 3.67**	**$ 6.87**	**$ 8.01**	**$ 8.87**	**$ 10.72**	**$ 14.59**	**$ 16.11**	**$ 16.66**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 1.45	$ 4.74	$ 8.63	$ 13.57	$ 12.40	$ 11.17	$ 10.69	$ 10.19	$ 9.21	$ 9.82	$ 10.95
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.34)	$ (5.29)	$ (5.14)	$ (4.92)	$ (4.83)	$ (5.03)	$ (5.30)	$ (5.21)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.66)	$ (2.44)	$ (2.80)	$ (2.73)	$ (2.51)	$ (2.18)	$ (1.80)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.93)	$ (1.31)	$ (1.59)	$ (1.48)	$ (1.24)	$ (1.13)	$ (1.11)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.45**	**$ 4.74**	**$ 8.63**	**$ 11.23**	**$ 5.53**	**$ 2.29**	**$ 1.38**	**$ 1.15**	**$ 0.42**	**$ 1.22**	**$ 2.82**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.30	$ 0.25	$ 0.08	$ 0.05	$ 0.05	$ -	$ -	$ 0.16
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 4.52**	**$ 7.47**	**$ 16.21**	**$ 22.87**	**$ 18.28**	**$ 16.97**	**$ 18.32**	**$ 19.94**	**$ 23.24**	**$ 25.59**	**$ 27.44**
TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.54**	**$ 122.72**	**$ 140.22**	**$ 133.66**	**$ 140.17**	**$ 158.86**	**$ 180.66**	**$ 188.83**	**$ 200.05**	**$ 206.75**	**$ 219.77**	**$ 226.55**	**$ 233.87**
CAGR (2019 BASE)															
CAGR (MAY 2020 BASE)															

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - COMPANY PREFERRED PLAN, COMPANY METHODOLOGY

RESIDENTIAL Schedule 1 (1,000 kWh)	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 80.98	$ 80.33	$ 81.41	$ 82.34	$ 82.51	$ 82.62	$ 83.50	$ 85.01	$ 86.52	$ 88.01	$ 89.31	$ 90.83	$ 92.14
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 38.89	$ 39.80	$ 40.08	$ 40.00	$ 39.95	$ 39.96	$ 39.95	$ 40.18	$ 40.25	$ 40.29	$ 40.31	$ 40.22	$ 40.13
FUEL - RIDER A	$ 41.68	$ 42.05	$ 44.57	$ 47.50	$ 49.43	$ 50.75	$ 53.23	$ 54.87	$ 57.10	$ 60.75	$ 63.15	$ 66.08	$ 70.70
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1.93	$ 1.88	$ 1.83	$ 1.76	$ 1.70	$ 1.64	$ 1.59	$ 1.54	$ 1.50	$ 1.46	$ 1.43	$ 1.39	$ 1.35
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 0.23	$ 0.22	$ 0.22	$ 0.21	$ 0.21	$ 0.21	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.18	$ 0.18
Generation Infrastructure													
GENERATION RIDERS [2]	$ 5.26	$ 4.92	$ 4.76	$ 4.58	$ 4.54	$ 4.47	$ 4.10	$ 4.12	$ 3.94	$ 3.72	$ 3.48	$ 2.98	$ 2.98
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 6.38	$ 6.10	$ 5.81	$ 5.45	$ 5.10	$ 4.71	$ 4.37	$ 4.05	$ 3.78	$ 3.53	$ 3.29	$ 3.08	$ 2.87
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 2.04	$ 1.80	$ 1.70	$ 1.61	$ 1.52	$ 1.43	$ 1.36	$ 1.28	$ 1.23	$ 1.17	$ 1.11	$ 1.06	$ 1.02
Distribution Infrastructure [3]													
DISTRIBUTION RIDERS	$ 10.49	$ 10.10	$ 9.70	$ 9.32	$ 8.95	$ 8.58	$ 8.22	$ 7.85	$ 7.38	$ 7.00	$ 6.54	$ 3.38	$ 3.13
A5 Environmental													
RIDER E [4]	$ 1.12	$ 1.04	$ 0.96	$ 0.88	$ 0.82	$ 0.75	$ 0.70	$ 0.64	$ 0.60	$ 0.55	$ 0.57	$ 0.30	$ 0.28
RIDER CCR	$ 1.80	$ 2.80	$ 1.81	$ 1.74	$ 0.23	$ 0.08	$ 0.20	$ 0.08	$ 0.01	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources													
INCREMENTAL GENERIC DSM	$ 2.00	$ 2.00	$ 2.00	$ 7.00	$ 9.00	$ 9.00	$ 4.00	$ 3.00	$ 3.00	$ 3.00	$ 2.00	$ 2.00	$ 4.00
GENERIC GAS	$ 21.40	$ 23.52	$ 24.26	$ 23.51	$ 22.61	$ 21.52	$ 20.24	$ 19.07	$ 18.12	$ 17.16	$ 16.27	$ 15.43	$ 14.60
RPS Program-Related Resources													
RIDER RPS [5]	$ 6.98	$ 5.92	$ 4.62	$ 5.70	$ 7.14	$ 8.16	$ 6.41	$ 7.69	$ 8.67	$ 9.67	$ 10.70	$ 11.89	$ 13.63
RIDER CE [6]	$ 33.96	$ 36.95	$ 39.86	$ 42.39	$ 44.67	$ 45.76	$ 46.34	$ 46.37	$ 46.16	$ 45.10	$ 44.88	$ 44.48	$ 44.26
RIDER CE - FUEL BENEFIT	$ (11.66)	$ (13.08)	$ (14.44)	$ (16.40)	$ (18.55)	$ (19.31)	$ (20.79)	$ (21.78)	$ (23.70)	$ (27.58)	$ (29.86)	$ (32.90)	$ (36.90)
RIDER CE - REC PROXY VALUE	$ (3.13)	$ (2.85)	$ (2.43)	$ (1.84)	$ (1.88)	$ (1.90)	$ (1.90)	$ (1.89)	$ (1.85)	$ (1.89)	$ (1.94)	$ (1.97)	$ (2.00)
RIDER CE - CAPACITY OFFSET	$ (1.54)	$ (1.86)	$ (2.20)	$ (2.50)	$ (2.73)	$ (2.94)	$ (3.09)	$ (3.13)	$ (3.01)	$ (2.88)	$ (2.63)	$ (2.50)	$ (2.30)
TOTAL RIDER CE	**$ 17.64**	**$ 19.16**	**$ 20.78**	**$ 21.65**	**$ 21.51**	**$ 21.62**	**$ 20.56**	**$ 19.57**	**$ 17.61**	**$ 12.74**	**$ 10.45**	**$ 7.11**	**$ 3.06**
RIDER OSW [7]	$ 13.04	$ 16.10	$ 18.38	$ 23.33	$ 25.35	$ 25.79	$ 29.54	$ 27.38	$ 25.85	$ 24.43	$ 23.17	$ 22.19	$ 21.53
RIDER OSW - FUEL BENEFIT	$ (5.34)	$ (6.69)	$ (6.70)	$ (6.63)	$ (6.60)	$ (7.23)	$ (11.57)	$ (11.69)	$ (12.14)	$ (12.61)	$ (13.15)	$ (13.72)	$ (14.20)
RIDER OSW - REC PROXY VALUE	$ (1.44)	$ (1.13)	$ (1.06)	$ (0.82)	$ (0.75)	$ (0.69)	$ (0.68)	$ (1.03)	$ (0.96)	$ (0.93)	$ (0.90)	$ (0.87)	$ (0.85)
RIDER OSW - CAPACITY OFFSET	$ (1.17)	$ (1.37)	$ (1.48)	$ (1.50)	$ (1.51)	$ (1.51)	$ (2.19)	$ (2.65)	$ (2.63)	$ (2.62)	$ (2.59)	$ (2.56)	$ (2.52)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 5.10**	**$ 6.92**	**$ 9.14**	**$ 14.39**	**$ 16.49**	**$ 16.38**	**$ 15.11**	**$ 12.02**	**$ 10.11**	**$ 8.28**	**$ 6.53**	**$ 5.04**	**$ 3.96**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 0.44	$ 1.05	$ 2.14	$ 3.69	$ 5.64	$ 7.79	$ 10.12	$ 12.99	$ 14.64	$ 15.57	$ 15.87	$ 15.69	$ 14.62
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 30.15**	**$ 33.05**	**$ 36.68**	**$ 45.43**	**$ 50.78**	**$ 53.94**	**$ 52.20**	**$ 52.28**	**$ 51.03**	**$ 46.26**	**$ 43.55**	**$ 39.73**	**$ 35.27**
TOTAL	**$ 244.34**	**$ 249.59**	**$ 255.79**	**$ 271.32**	**$ 277.33**	**$ 279.67**	**$ 273.82**	**$ 274.15**	**$ 274.64**	**$ 273.10**	**$ 271.21**	**$ 266.66**	**$ 268.65**
CAGR (2019 BASE)			4.7%				4.1%						3.1%
CAGR (MAY 2020 BASE)			5.2%				4.5%						3.3%

[1] Publicly available, annualized tariff rates consistent with the rebut
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and L
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all appr
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC
[6] Includes specific Company-owned projects and PPAs proposed in 2
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the o

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - COMPANY PREFERRED PLAN, COMPANY METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036
DISTRIBUTION & GENERATION (BASE) [1]	272.78	272.78	272.78	272.78	266.31	266.31	259.72	264.59	312.72	316.69	326.37	330.61	331.82	337.35	337.37	334.76	329.97	333.94	337.14
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	-	-	-	-	(3.27)	(3.00)	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANSMISSION - RIDER T	76.59	76.59	89.37	70.55	58.84	65.08	90.40	95.33	128.29	133.67	147.29	159.89	170.57	177.65	183.10	187.89	192.26	193.61	193.22
FUEL - RIDER A	139.52	104.14	102.13	122.69	212.27	171.52	124.41	178.08	210.61	198.20	194.21	199.84	215.52	228.99	241.03	250.06	252.28	267.40	284.99
FUEL SECURITIZATION	-	-	-	-	-	-	20.23	17.44	18.29	17.80	16.99	16.58	14.75	-	-	-	-	-	-
DSM	5.33	5.33	6.49	6.22	6.42	6.77	6.36	6.96	10.26	11.28	11.55	11.25	11.04	10.74	10.22	9.82	9.58	9.29	8.97
RIDER PIPP - UNIVERSAL SERVICE FEE	-	-	-	0.16	0.16	4.39	-	-	1.56	1.54	1.52	1.49	1.45	1.41	1.38	1.35	1.32	1.30	1.27
Generation Infrastructure																			
GENERATION RIDERS [2]	61.54	58.22	57.99	65.89	59.26	27.33	26.51	35.96	23.91	29.84	29.86	30.58	29.92	27.95	26.79	26.74	25.01	24.20	23.25
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	-	-	-	-	8.24	4.46	5.22	15.37	17.90	18.94	22.66	26.69	31.24	33.47	33.46	32.40	30.99	29.55	27.69
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	-	-	-	-	-	-	-	-	2.75	5.42	7.40	10.25	12.38	11.72	11.04	10.34	9.13	8.64	8.17
Distribution Infrastructure [3]																			
DISTRIBUTION RIDERS	8.75	5.90	5.90	9.30	15.41	10.63	26.83	26.10	34.30	38.07	41.95	44.57	47.52	44.49	43.41	42.59	41.73	40.95	40.00
A5 Environmental																			
RIDER E [4]	9.44	9.44	7.48	5.99	7.76	9.77	5.48	3.07	2.68	3.41	5.38	6.01	7.54	7.13	6.17	5.69	5.26	4.87	4.50
RIDER CCR	-	-	-	17.67	17.73	14.26	7.10	7.10	10.94	14.27	13.70	13.11	12.49	11.87	11.29	10.81	16.81	10.87	10.44
RIDER RGGI	-	-	-	14.36	-	26.55	-	-	-	-	-	-	-	-	-	-	-	-	-
Additional Resources																			
INCREMENTAL GENERIC DSM	-	-	-	-	-	-	-	-	20.00	25.00	32.00	12.00	12.00	11.00	11.00	10.00	10.00	12.00	36.00
GENERIC GAS	-	-	-	-	-	-	-	-	-	6.03	17.65	30.05	43.84	59.33	75.73	108.73	119.50	123.33	119.50
RPS Program-Related Resources																			
RIDER RPS [5]	-	-	-	1.09	10.86	7.90	28.13	46.06	33.82	39.53	48.13	48.14	49.36	49.58	46.81	41.86	35.51	27.73	34.20
RIDER CE [6]	-	-	-	0.92	7.18	14.46	17.97	27.64	54.16	62.57	77.05	91.88	121.65	145.90	162.67	179.06	195.08	210.62	224.20
RIDER CE - FUEL BENEFIT	-	-	-	-	(2.29)	(6.57)	(7.29)	(8.14)	(13.98)	(18.21)	(22.34)	(22.66)	(32.21)	(45.48)	(58.43)	(69.94)	(78.49)	(86.66)	(98.39)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(6.11)	(4.09)	(8.08)	(12.14)	(12.39)	(17.02)	(19.06)	(18.76)	(17.11)	(14.56)	(11.03)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.13)	(0.14)	-	(4.29)	(1.94)	(1.85)	(4.16)	(5.77)	(6.25)	(6.56)	(6.85)	(7.91)	(9.53)	(11.27)	(12.80)
TOTAL RIDER CE	**-**	**-**	**-**	**0.92**	**4.76**	**7.75**	**10.68**	**15.20**	**32.14**	**38.41**	**42.46**	**51.31**	**70.79**	**76.84**	**78.34**	**82.45**	**89.96**	**98.13**	**101.98**
RIDER OSW [7]	-	-	-	-	5.80	22.73	35.36	60.00	62.30	56.74	54.30	51.79	46.79	49.91	55.65	66.30	81.89	93.51	118.72
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	(12.19)	(31.41)	(30.81)	(29.53)	(28.99)	(30.20)	(31.78)	(31.25)	(32.02)	(40.11)	(40.21)	(39.79)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	(3.94)	(14.62)	(16.79)	(16.39)	(15.05)	(13.05)	(10.82)	(8.61)	(6.78)	(6.35)	(4.93)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	(4.65)	(6.64)	(8.07)	(7.50)	(6.30)	(5.72)	(5.64)	(5.93)	(6.95)	(7.55)	(7.61)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**5.80**	**22.73**	**35.36**	**47.81**	**22.30**	**4.66**	**(0.10)**	**(1.10)**	**(4.76)**	**(0.64)**	**7.94**	**19.73**	**28.04**	**39.40**	**66.40**
NUCLEAR SMALL MODULAR REACTORS [8]	-	-	-	-	-	-	-	1.40	1.16	0.41	0.23	0.23	-	-	0.79	2.24	5.36	10.87	18.75
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**2.01**	**21.42**	**38.38**	**74.18**	**110.48**	**89.42**	**83.02**	**90.72**	**98.57**	**115.39**	**125.78**	**133.87**	**146.28**	**158.87**	**176.12**	**221.33**
TOTAL	**573.95**	**532.40**	**542.13**	**587.62**	**670.55**	**642.44**	**646.43**	**760.47**	**883.61**	**903.18**	**959.26**	**991.49**	**1,057.49**	**1,088.90**	**1,125.86**	**1,177.46**	**1,202.71**	**1,236.07**	**1,316.47**
CAGR (2019 BASE)																		4.9%	
CAGR (MAY 2020 BASE)																		5.5%	

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
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SMALL GENERAL BILL PROJECTION - COMPANY PREFERRED PLAN,
COMPANY METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 336.43	$ 335.41	$ 338.21	$ 344.23	$ 350.21	$ 356.07	$ 360.91	$ 366.81	$ 371.63
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 193.00	$ 193.04	$ 193.00	$ 194.09	$ 194.42	$ 194.65	$ 194.75	$ 194.32	$ 193.88
FUEL - RIDER A	$ 296.56	$ 304.50	$ 319.39	$ 329.21	$ 342.62	$ 364.52	$ 378.92	$ 396.47	$ 424.18
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 8.66	$ 8.36	$ 8.09	$ 7.84	$ 7.66	$ 7.45	$ 7.26	$ 7.10	$ 6.91
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1.25	$ 1.23	$ 1.14	$ 1.13	$ 1.13	$ 1.12	$ 1.11	$ 1.11	$ 1.10
Generation Infrastructure									
GENERATION RIDERS [2]	$ 23.06	$ 22.76	$ 20.82	$ 20.92	$ 20.05	$ 18.93	$ 17.69	$ 15.15	$ 15.13
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 25.90	$ 23.96	$ 22.21	$ 20.60	$ 19.24	$ 17.94	$ 16.74	$ 15.64	$ 14.59
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 7.72	$ 7.28	$ 6.89	$ 6.53	$ 6.23	$ 5.93	$ 5.65	$ 5.41	$ 5.21
Distribution Infrastructure [3]									
DISTRIBUTION RIDERS	$ 39.26	$ 38.42	$ 37.67	$ 36.74	$ 35.44	$ 34.34	$ 32.88	$ 16.84	$ 16.03
A5 Environmental									
RIDER E [4]	$ 4.15	$ 3.82	$ 3.54	$ 3.26	$ 3.04	$ 2.80	$ 2.92	$ 1.55	$ 1.43
RIDER CCR	$ 1.38	$ 0.48	$ 1.17	$ 0.50	$ 0.05	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources									
INCREMENTAL GENERIC DSM	$ 45.00	$ 48.00	$ 19.00	$ 14.00	$ 13.00	$ 13.00	$ 12.00	$ 11.00	$ 18.00
GENERIC GAS	$ 114.91	$ 109.39	$ 102.88	$ 96.97	$ 92.12	$ 87.28	$ 82.75	$ 78.48	$ 74.26
RPS Program-Related Resources									
RIDER RPS [5]	$ 42.83	$ 48.94	$ 38.48	$ 46.11	$ 52.03	$ 58.01	$ 64.19	$ 71.33	$ 81.76
RIDER CE [6]	$ 236.50	$ 242.72	$ 246.38	$ 247.72	$ 247.73	$ 243.37	$ 243.29	$ 242.21	$ 241.97
RIDER CE - FUEL BENEFIT	$ (111.28)	$ (115.84)	$ (124.71)	$ (130.66)	$ (142.18)	$ (165.46)	$ (179.16)	$ (197.39)	$ (221.41)
RIDER CE - REC PROXY VALUE	$ (11.30)	$ (11.38)	$ (11.41)	$ (11.33)	$ (11.07)	$ (11.36)	$ (11.65)	$ (11.84)	$ (11.98)
RIDER CE - CAPACITY OFFSET	$ (13.97)	$ (15.04)	$ (15.83)	$ (16.02)	$ (15.41)	$ (14.75)	$ (13.46)	$ (12.77)	$ (11.75)
TOTAL RIDER CE	**$ 99.95**	**$ 100.46**	**$ 94.44**	**$ 89.71**	**$ 79.07**	**$ 51.80**	**$ 39.03**	**$ 20.21**	**$ (3.16)**
RIDER OSW [7]	$ 128.97	$ 131.27	$ 150.37	$ 139.39	$ 131.57	$ 124.35	$ 117.98	$ 112.97	$ 109.65
RIDER OSW - FUEL BENEFIT	$ (39.59)	$ (43.35)	$ (69.43)	$ (70.11)	$ (72.86)	$ (75.63)	$ (78.90)	$ (82.31)	$ (85.19)
RIDER OSW - REC PROXY VALUE	$ (4.51)	$ (4.12)	$ (4.07)	$ (6.16)	$ (5.74)	$ (5.56)	$ (5.39)	$ (5.24)	$ (5.08)
RIDER OSW - CAPACITY OFFSET	$ (7.67)	$ (7.67)	$ (11.13)	$ (13.47)	$ (13.42)	$ (13.31)	$ (13.20)	$ (13.01)	$ (12.85)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 77.20**	**$ 76.13**	**$ 65.74**	**$ 49.65**	**$ 39.55**	**$ 29.85**	**$ 20.50**	**$ 12.41**	**$ 6.53**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 28.68	$ 39.58	$ 51.47	$ 66.08	$ 74.45	$ 79.16	$ 80.72	$ 79.81	$ 74.37
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 248.66**	**$ 265.12**	**$ 250.13**	**$ 251.55**	**$ 245.10**	**$ 218.82**	**$ 204.44**	**$ 183.76**	**$ 159.50**
TOTAL	**$ 1,345.95**	**$ 1,361.76**	**$ 1,324.15**	**$ 1,327.56**	**$ 1,330.31**	**$ 1,322.85**	**$ 1,318.01**	**$ 1,293.64**	**$ 1,301.85**
CAGR (2019 BASE)			4.3%						3.2%
CAGR (MAY 2020 BASE)			4.7%						3.5%

[1] Publicly available, annualized tariff rates consistent with the rebuttal p
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC prox
[6] Includes specific Company-owned projects and PPAs proposed in 2020
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the outpu

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - COMPANY PREFERRED PLAN, COMPANY METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 127,019.69	$ 127,019.69	$ 122,333.63	$ 123,780.20	$ 151,307.33	$ 143,305.96	$ 148,489.00	$ 150,045.69
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (1,597.09)	$ (1,464.00)	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 37,760.00	$ 37,760.00	$ 42,270.00	$ 45,260.00	$ 35,280.00	$ 47,770.00	$ 60,900.00	$ 65,460.00	$ 78,210.00	$ 74,570.00	$ 82,170.00	$ 89,200.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 178,080.00	$ 210,606.00	$ 198,198.00	$ 194,214.00	$ 199,836.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,226.00	$ 17,436.00	$ 18,288.00	$ 17,802.00	$ 16,992.00	$ 16,578.00
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 330.00	$ 570.00	$ 1,050.00	$ 1,530.00	$ 1,602.00	$ 1,656.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ 1,562.82	$ 1,541.03	$ 1,515.31	$ 1,485.05
Generation Infrastructure												
GENERATION RIDERS [2]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 19,100.00	$ 14,540.00	$ 19,650.00	$ 19,700.00	$ 20,180.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 8,370.00	$ 10,890.00	$ 12,480.00	$ 14,950.00	$ 17,620.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,670.00	$ 3,570.00	$ 4,880.00	$ 6,760.00
Distribution Infrastructure [3]												
DISTRIBUTION RIDERS	$ -	$ -	$ -	$ 20.00	$ 1,290.00	$ 510.00	$ 2,900.00	$ 1,260.00	$ 1,790.00	$ 1,910.00	$ 2,030.00	$ 2,090.00
A5 Environmental												
RIDER E [4]	$ 5,560.00	$ 5,560.00	$ 4,300.00	$ 3,140.00	$ 4,860.00	$ 4,440.00	$ 3,260.00	$ 1,630.00	$ 1,630.00	$ 2,250.00	$ 3,550.00	$ 3,970.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,098.00	$ 7,098.00	$ 10,938.00	$ 14,274.00	$ 13,704.00	$ 13,110.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 26,550.00	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,980.00	$ 11,640.00	$ 19,820.00
RPS Program-Related Resources												
RIDER RPS [5]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 46,056.00	$ 33,822.00	$ 39,528.00	$ 48,126.00	$ 48,138.00
RIDER CE [6]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 14,970.00	$ 23,284.00	$ 42,628.00	$ 54,048.00	$ 63,912.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (7,830.00)	$ (10,230.00)	$ (18,210.00)	$ (22,344.00)	$ (22,662.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,464.00)	$ (4,092.00)	$ (8,082.00)	$ (12,138.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (800.00)	$ (1,220.00)	$ (2,720.00)	$ (3,750.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,960.00**	**$ 7,790.00**	**$ 19,106.00**	**$ 20,902.00**	**$ 25,362.00**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 33,590.00	$ 35,100.00	$ 32,680.00	$ 31,310.00	$ 29,880.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,284.00)	$ (33,504.00)	$ (30,810.00)	$ (29,532.00)	$ (28,992.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,206.00)	$ (14,622.00)	$ (16,794.00)	$ (16,392.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,620.00)	$ (3,830.00)	$ (4,650.00)	$ (4,330.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 20,306.00**	**$ (5,230.00)**	**$ (16,582.00)**	**$ (19,666.00)**	**$ (19,834.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 750.00	$ 710.00	$ 270.00	$ 160.00	$ 150.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 72,072.00**	**$ 37,092.00**	**$ 42,322.00**	**$ 49,522.00**	**$ 53,816.00**
TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 432,893.69**	**$ 412,671.63**	**$ 494,856.20**	**$ 539,574.15**	**$ 537,382.99**	**$ 564,958.31**	**$ 596,166.74**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

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LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041
DISTRIBUTION & GENERATION (BASE) [1]	$ 149,586.32	$ 151,951.16	$ 150,650.50	$ 147,574.63	$ 143,043.84	$ 144,268.43	$ 144,958.72	$ 143,025.01	$ 140,857.63	$ 141,196.89	$ 143,623.15	$ 145,996.73
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 95,160.00	$ 99,110.00	$ 102,140.00	$ 104,820.00	$ 107,260.00	$ 108,010.00	$ 107,790.00	$ 107,670.00	$ 107,690.00	$ 107,670.00	$ 108,280.00	$ 108,460.00
FUEL - RIDER A	$ 215,520.00	$ 228,990.00	$ 241,032.00	$ 250,062.00	$ 252,276.00	$ 267,402.00	$ 284,994.00	$ 296,562.00	$ 304,500.00	$ 319,392.00	$ 329,208.00	$ 342,624.00
FUEL SECURITIZATION	$ 14,754.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,602.00	$ 1,548.00	$ 1,416.00	$ 1,368.00	$ 1,356.00	$ 1,326.00	$ 1,284.00	$ 1,242.00	$ 1,194.00	$ 1,158.00	$ 1,122.00	$ 1,098.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1,448.96	$ 1,414.60	$ 1,379.13	$ 1,350.56	$ 1,322.84	$ 1,296.03	$ 1,268.22	$ 1,247.84	$ 1,230.34	$ 1,142.70	$ 1,133.41	$ 1,126.37
Generation Infrastructure												
GENERATION RIDERS [2]	$ 19,750.00	$ 18,470.00	$ 17,710.00	$ 17,660.00	$ 16,540.00	$ 16,000.00	$ 15,380.00	$ 15,230.00	$ 15,050.00	$ 13,800.00	$ 13,850.00	$ 13,290.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 20,620.00	$ 22,110.00	$ 22,100.00	$ 21,410.00	$ 20,480.00	$ 19,540.00	$ 18,310.00	$ 17,140.00	$ 15,850.00	$ 14,700.00	$ 13,630.00	$ 12,740.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 8,170.00	$ 7,740.00	$ 7,290.00	$ 6,830.00	$ 6,040.00	$ 5,710.00	$ 5,400.00	$ 5,110.00	$ 4,820.00	$ 4,560.00	$ 4,320.00	$ 4,120.00
Distribution Infrastructure [3]												
DISTRIBUTION RIDERS	$ 2,020.00	$ 1,860.00	$ 1,680.00	$ 1,560.00	$ 1,450.00	$ 1,340.00	$ 1,240.00	$ 1,140.00	$ 1,050.00	$ 980.00	$ 910.00	$ 810.00
A5 Environmental												
RIDER E [4]	$ 4,960.00	$ 4,700.00	$ 4,090.00	$ 3,760.00	$ 3,470.00	$ 3,220.00	$ 2,970.00	$ 2,740.00	$ 2,530.00	$ 2,340.00	$ 2,170.00	$ 2,010.00
RIDER CCR	$ 12,486.00	$ 11,874.00	$ 11,292.00	$ 10,812.00	$ 16,806.00	$ 10,866.00	$ 10,440.00	$ 1,380.00	$ 480.00	$ 1,170.00	$ 498.00	$ 48.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 28,940.00	$ 39,180.00	$ 50,020.00	$ 71,840.00	$ 78,980.00	$ 81,540.00	$ 79,030.00	$ 76,020.00	$ 72,380.00	$ 68,100.00	$ 64,200.00	$ 61,000.00
RPS Program-Related Resources												
RIDER RPS [5]	$ 49,356.00	$ 49,578.00	$ 46,806.00	$ 41,856.00	$ 35,508.00	$ 27,726.00	$ 34,200.00	$ 42,828.00	$ 48,942.00	$ 38,478.00	$ 46,110.00	$ 52,032.00
RIDER CE [6]	$ 85,962.00	$ 104,036.00	$ 117,060.00	$ 129,648.00	$ 141,840.00	$ 153,654.00	$ 163,992.00	$ 173,556.00	$ 179,108.00	$ 183,138.00	$ 186,764.00	$ 189,364.00
RIDER CE - FUEL BENEFIT	$ (32,214.00)	$ (45,480.00)	$ (58,434.00)	$ (69,942.00)	$ (78,486.00)	$ (86,664.00)	$ (98,394.00)	$ (111,276.00)	$ (115,836.00)	$ (124,710.00)	$ (130,656.00)	$ (142,182.00)
RIDER CE - REC PROXY VALUE	$ (12,390.00)	$ (17,022.00)	$ (19,056.00)	$ (18,762.00)	$ (17,112.00)	$ (14,556.00)	$ (11,028.00)	$ (11,298.00)	$ (11,376.00)	$ (11,406.00)	$ (11,328.00)	$ (11,070.00)
RIDER CE - CAPACITY OFFSET	$ (4,110.00)	$ (4,290.00)	$ (4,480.00)	$ (5,180.00)	$ (6,250.00)	$ (7,380.00)	$ (8,370.00)	$ (9,170.00)	$ (9,870.00)	$ (10,380.00)	$ (10,510.00)	$ (10,110.00)
TOTAL RIDER CE	**$ 37,248.00**	**$ 37,244.00**	**$ 35,090.00**	**$ 35,764.00**	**$ 39,992.00**	**$ 45,054.00**	**$ 46,200.00**	**$ 41,812.00**	**$ 42,026.00**	**$ 36,642.00**	**$ 34,270.00**	**$ 26,002.00**
RIDER OSW [7]	$ 27,010.00	$ 28,850.00	$ 32,190.00	$ 38,360.00	$ 47,400.00	$ 54,180.00	$ 68,830.00	$ 74,830.00	$ 76,190.00	$ 87,360.00	$ 81,010.00	$ 76,500.00
RIDER OSW - FUEL BENEFIT	$ (30,198.00)	$ (31,776.00)	$ (31,254.00)	$ (32,022.00)	$ (40,110.00)	$ (40,206.00)	$ (39,786.00)	$ (39,594.00)	$ (43,350.00)	$ (69,432.00)	$ (70,110.00)	$ (72,864.00)
RIDER OSW - REC PROXY VALUE	$ (15,054.00)	$ (13,050.00)	$ (10,818.00)	$ (8,610.00)	$ (6,780.00)	$ (6,354.00)	$ (4,926.00)	$ (4,512.00)	$ (4,116.00)	$ (4,068.00)	$ (6,156.00)	$ (5,742.00)
RIDER OSW - CAPACITY OFFSET	$ (3,640.00)	$ (3,310.00)	$ (3,260.00)	$ (3,440.00)	$ (4,030.00)	$ (4,370.00)	$ (4,410.00)	$ (4,450.00)	$ (4,450.00)	$ (6,470.00)	$ (7,830.00)	$ (7,800.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (21,882.00)**	**$ (19,286.00)**	**$ (13,142.00)**	**$ (5,712.00)**	**$ (3,520.00)**	**$ 3,250.00**	**$ 19,708.00**	**$ 26,274.00**	**$ 24,274.00**	**$ 7,390.00**	**$ (3,086.00)**	**$ (9,906.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ 520.00	$ 1,480.00	$ 3,540.00	$ 7,190.00	$ 12,400.00	$ 18,970.00	$ 26,190.00	$ 34,070.00	$ 43,750.00	$ 49,300.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 64,722.00**	**$ 67,536.00**	**$ 69,274.00**	**$ 73,388.00**	**$ 75,520.00**	**$ 83,220.00**	**$ 112,508.00**	**$ 129,884.00**	**$ 141,432.00**	**$ 116,580.00**	**$ 121,044.00**	**$ 117,428.00**
TOTAL	**$ 639,739.28**	**$ 656,483.76**	**$ 680,073.63**	**$ 712,435.19**	**$ 724,544.68**	**$ 743,738.46**	**$ 785,572.94**	**$ 798,390.85**	**$ 809,063.97**	**$ 792,789.59**	**$ 803,988.56**	**$ 810,751.10**
CAGR (2019 BASE)						4.8%				4.2%		
CAGR (MAY 2020 BASE)						5.7%				4.8%		

[1] Publicly available, annualized tariff rates consistent with tl
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US
[3] Consolidated Distribution Riders GT, U, and RBB. Includes
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, a
[6] Includes specific Company-owned projects and PPAs prop
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate REC

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - COMPANY PREFERRED PLAN, COMPANY METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 148,267.98	$ 149,827.26	$ 152,054.92	$ 153,531.33
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 108,590.00	$ 108,650.00	$ 108,410.00	$ 108,160.00
FUEL - RIDER A	$ 364,518.00	$ 378,918.00	$ 396,468.00	$ 424,182.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -
DSM	$ 1,068.00	$ -	$ 1,020.00	$ 990.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1,120.49	$ 1,113.12	$ 1,107.45	$ 1,103.00
Generation Infrastructure				
GENERATION RIDERS [2]	$ 12,520.00	$ 11,700.00	$ 10,050.00	$ 10,020.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 11,880.00	$ 11,090.00	$ 10,360.00	$ 9,670.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 3,930.00	$ 3,740.00	$ 3,580.00	$ 3,450.00
Distribution Infrastructure [3]				
DISTRIBUTION RIDERS	$ 750.00	$ 660.00	$ 590.00	$ 550.00
A5 Environmental				
RIDER E [4]	$ 1,860.00	$ 1,940.00	$ 1,020.00	$ 940.00
RIDER CCR	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -
Additional Resources				
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -
GENERIC GAS	$ 57,800.00	$ 54,810.00	$ 51,990.00	$ 49,200.00
RPS Program-Related Resources				
RIDER RPS [5]	$ 58,014.00	$ 64,188.00	$ 71,328.00	$ 81,762.00
RIDER CE [6]	$ 188,986.00	$ 92,472.00	$ 192,994.00	$ 194,918.00
RIDER CE - FUEL BENEFIT	$ (165,456.00)	$ (179,160.00)	$ (197,394.00)	$ (221,406.00)
RIDER CE - REC PROXY VALUE	$ (11,358.00)	$ (11,646.00)	$ (11,844.00)	$ (11,976.00)
RIDER CE - CAPACITY OFFSET	$ (9,670.00)	$ -	$ (8,380.00)	$ (7,720.00)
TOTAL RIDER CE	**$ 2,502.00**	**$ (98,334.00)**	**$ (24,624.00)**	**$ (46,184.00)**
RIDER OSW [7]	$ 72,320.00	$ -	$ 65,760.00	$ 63,850.00
RIDER OSW - FUEL BENEFIT	$ (75,630.00)	$ (78,900.00)	$ (82,314.00)	$ (85,194.00)
RIDER OSW - REC PROXY VALUE	$ (5,556.00)	$ (5,388.00)	$ (5,238.00)	$ (5,076.00)
RIDER OSW - CAPACITY OFFSET	$ (7,740.00)	$ -	$ (7,570.00)	$ (7,480.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (16,606.00)**	**$ (84,288.00)**	**$ (29,362.00)**	**$ (33,900.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 52,420.00	$ 53,470.00	$ 52,870.00	$ 49,280.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 96,330.00**	**$ (64,964.00)**	**$ 70,212.00**	**$ 50,958.00**
TOTAL	**$ 808,634.47**	**$ 657,484.38**	**$ 806,862.37**	**$ 812,754.33**
CAGR (2019 BASE)				3.3%
CAGR (MAY 2020 BASE)				3.8%

[1] Publicly available, annualized tariff rates consistent with tl
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US
[3] Consolidated Distribution Riders GT, U, and RBB. Includes
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, a
[6] Includes specific Company-owned projects and PPAs prop
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate REC

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, COMPANY METHODOLOGY

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 60.93	$ 60.93	$ 60.71	$ 60.71	$ 73.57	$ 75.80	$ 77.97	$ 79.06	$ 79.57	$ 80.63	$ 80.99	$ 80.81	$ 79.33	$ 80.60	$ 80.77
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (0.47)	$ (0.43)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	$ 12.91	$ 15.58	$ 19.40	$ 20.86	$ 23.46	$ 27.65	$ 30.17	$ 32.32	$ 34.04	$ 35.38	$ 36.53	$ 37.46	$ 37.87	$ 37.92	$ 38.03
FUEL - RIDER A	$ 23.25	$ 17.36	$ 17.02	$ 20.45	$ 35.38	$ 28.59	$ 20.74	$ 29.68	$ 34.94	$ 32.87	$ 32.22	$ 33.10	$ 35.49	$ 37.49	$ 39.40	$ 40.63	$ 40.36	$ 43.89	$ 48.88
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.37	$ 2.91	$ 3.05	$ 2.97	$ 2.83	$ 2.76	$ 2.46	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1.13	$ 1.13	$ 1.47	$ 1.31	$ 1.60	$ 1.84	$ 1.55	$ 1.57	$ 2.04	$ 2.22	$ 2.27	$ 2.22	$ 2.17	$ 2.11	$ 2.01	$ 1.93	$ 1.88	$ 1.83	$ 1.76
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 0.03	$ 0.03	$ 0.73	$ -	$ -	$ 0.26	$ 0.26	$ 0.25	$ 0.25	$ 0.24	$ 0.24	$ 0.23	$ 0.23	$ 0.22	$ 0.22	$ 0.21
Generation Infrastructure																			
GENERATION RIDERS [2]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	$ 14.51	$ 6.67	$ 6.57	$ 7.57	$ 5.10	$ 5.87	$ 5.88	$ 6.02	$ 5.91	$ 5.51	$ 5.28	$ 5.26	$ 4.92	$ 4.76	$ 4.58
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 2.07	$ 0.93	$ 1.29	$ 3.48	$ 3.82	$ 3.73	$ 4.46	$ 5.25	$ 6.15	$ 6.59	$ 6.58	$ 6.38	$ 6.10	$ 5.81	$ 5.45
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.59	$ 1.07	$ 1.46	$ 2.02	$ 2.44	$ 2.31	$ 2.17	$ 2.04	$ 1.80	$ 1.70	$ 1.61
Distribution Infrastructure [3]																			
DISTRIBUTION RIDERS	$ 1.84	$ 1.40	$ 1.40	$ 2.16	$ 3.84	$ 2.53	$ 7.81	$ 6.77	$ 9.04	$ 10.00	$ 10.95	$ 11.55	$ 12.19	$ 11.28	$ 10.87	$ 10.49	$ 10.10	$ 9.70	$ 9.32
A5 Environmental																			
RIDER E [4]	$ 1.99	$ 1.99	$ 1.67	$ 1.25	$ 1.95	$ 2.03	$ 1.35	$ 0.64	$ 0.57	$ 0.67	$ 1.06	$ 1.18	$ 1.48	$ 1.40	$ 1.22	$ 1.12	$ 1.04	$ 0.96	$ 0.88
RIDER CCR	$ -	$ -	$ -	$ 2.95	$ 2.96	$ 2.38	$ 1.18	$ 1.18	$ 1.82	$ 2.38	$ 2.28	$ 2.19	$ 2.08	$ 1.98	$ 1.88	$ 1.80	$ 2.80	$ 1.81	$ 1.74
RIDER RGGI	$ -	$ -	$ -	$ 2.39	$ -	$ 4.43	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources																			
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.00	$ 5.00	$ 6.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 7.00
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.19	$ 3.47	$ 5.75	$ 7.80	$ 9.40	$ 10.18	$ 12.07	$ 11.69	$ 10.98	$ 10.31
BRUNSWICK - 2044 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.14	$ 0.14	$ 0.15	$ 0.16	$ 0.16	$ 0.14	$ 0.14	$ 0.13	$ 0.12	$ 0.13
GREENVILLE - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.14	$ 0.10	$ 0.44	$ 0.26	$ 0.09	$ 0.23	$ 0.19	$ 0.20	$ 0.19	$ 0.18	$ 0.16
LNG - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.11	$ 0.14	$ 0.13	$ 0.12	$ 0.11	$ 0.10	$ 0.09	$ 0.08	$ 0.07
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ -	$ -
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.01	$ 0.13	$ 0.12	$ 0.11	$ 0.10	$ 0.08	$ 0.07	$ 0.06
CERC GAS CT - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.34	$ 0.56	$ 0.51	$ 0.46	$ 0.41	$ 0.37	$ 0.33	$ 0.30
GAS CT GENERIC - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.62	$ 0.99	$ 0.89	$ 0.79	$ 0.70	$ 0.61
RPS Program-Related Resources																			
RIDER RPS [5]	$ -	$ -	$ -	$ 0.18	$ 1.81	$ 1.32	$ 4.69	$ 7.68	$ 5.64	$ 6.59	$ 8.02	$ 8.03	$ 8.24	$ 8.31	$ 8.07	$ 7.67	$ 6.53	$ 4.36	$ 4.17
RIDER CE [6]	$ -	$ -	$ -	$ 0.19	$ 1.67	$ 2.59	$ 4.10	$ 6.17	$ 10.61	$ 12.21	$ 14.92	$ 17.90	$ 23.52	$ 27.85	$ 30.80	$ 35.20	$ 41.16	$ 47.25	$ 55.10
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.38)	$ (1.15)	$ (1.22)	$ (1.55)	$ (2.33)	$ (3.03)	$ (3.71)	$ (3.75)	$ (4.85)	$ (6.56)	$ (8.10)	$ (9.52)	$ (12.29)	$ (14.79)	$ (18.20)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.02)	$ (0.68)	$ (1.35)	$ (2.02)	$ (2.05)	$ (2.56)	$ (2.74)	$ (2.60)	$ (2.32)	$ (2.28)	$ (1.91)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.03)	$ (0.03)	$ -	$ (0.96)	$ (0.38)	$ (0.36)	$ (0.81)	$ (1.13)	$ (1.23)	$ (1.29)	$ (1.35)	$ (1.59)	$ (2.09)	$ (2.69)	$ (3.51)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 1.26**	**$ 1.41**	**$ 2.89**	**$ 3.67**	**$ 6.87**	**$ 8.14**	**$ 9.04**	**$ 11.00**	**$ 15.39**	**$ 17.45**	**$ 18.61**	**$ 21.49**	**$ 24.46**	**$ 27.50**	**$ 31.48**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 1.45	$ 4.74	$ 8.63	$ 13.57	$ 12.40	$ 11.17	$ 10.69	$ 9.71	$ 8.73	$ 8.94	$ 8.68	$ 8.40	$ 8.92	$ 11.40	$ 16.10
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.34)	$ (5.28)	$ (5.11)	$ (4.90)	$ (4.82)	$ (5.02)	$ (5.30)	$ (5.23)	$ (5.18)	$ (5.09)	$ (5.27)	$ (6.58)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.66)	$ (2.44)	$ (2.80)	$ (2.73)	$ (2.51)	$ (2.18)	$ (1.81)	$ (1.44)	$ (1.09)	$ (0.77)	$ (0.64)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.93)	$ (1.31)	$ (1.59)	$ (1.48)	$ (1.23)	$ (1.08)	$ (1.07)	$ (1.14)	$ (1.18)	$ (1.18)	$ (1.41)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.45**	**$ 4.74**	**$ 8.63**	**$ 11.23**	**$ 5.53**	**$ 2.31**	**$ 1.40**	**$ 0.68**	**$ (0.03)**	**$ 0.38**	**$ 0.58**	**$ 0.64**	**$ 1.56**	**$ 4.18**	**$ 7.47**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.30	$ 0.25	$ 1.42	$ 3.23	$ 6.52	$ 11.23	$ 17.27	$ 24.04	$ 31.65	$ 41.94	$ 49.56	$ 57.29
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 4.52**	**$ 7.47**	**$ 16.21**	**$ 22.87**	**$ 18.29**	**$ 18.46**	**$ 21.70**	**$ 26.23**	**$ 34.83**	**$ 43.41**	**$ 51.30**	**$ 61.45**	**$ 74.48**	**$ 85.60**	**$ 100.40**
TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.54**	**$ 122.72**	**$ 140.22**	**$ 133.66**	**$ 140.17**	**$ 158.23** E	**$ 180.68**	**$ 190.38**	**$ 203.64**	**$ 212.80**	**$ 229.92**	**$ 241.47**	**$ 252.63**	**$ 265.51**	**$ 276.22**	**$ 289.26**	**$ 312.26**
CAGR (2019 BASE)																		5.5%	
CAGR (MAY 2020 BASE)																		6.0%	

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, COMPANY METHODOLOGY

RESIDENTIAL Schedule 1 (1,000 kWh)	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 81.43	$ 82.07	$ 82.29	$ 83.33	$ 86.88	$ 87.10	$ 89.36	$ 92.32	$ 93.41
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 37.99	$ 38.02	$ 38.05	$ 37.16	$ 36.21	$ 35.32	$ 34.48	$ 33.62	$ 32.82
FUEL - RIDER A	$ 49.40	$ 51.53	$ 51.41	$ 48.19	$ 47.18	$ 50.19	$ 51.75	$ 49.57	$ 52.40
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1.70	$ 1.64	$ 1.59	$ 1.54	$ 1.50	$ 1.46	$ 1.43	$ 1.39	$ 1.35
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 0.21	$ 0.21	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.18	$ 0.18
Generation Infrastructure									
GENERATION RIDERS [2]	$ 4.56	$ 4.50	$ 4.12	$ 4.14	$ 3.98	$ 3.75	$ 3.51	$ 3.01	$ 2.98
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 5.10	$ 4.71	$ 4.37	$ 4.05	$ 3.78	$ 3.53	$ 3.29	$ 3.08	$ 2.87
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 1.52	$ 1.43	$ 1.36	$ 1.28	$ 1.23	$ 1.17	$ 1.11	$ 1.06	$ 1.02
Distribution Infrastructure [3]									
DISTRIBUTION RIDERS	$ 8.95	$ 8.58	$ 8.22	$ 7.85	$ 7.38	$ 7.00	$ 6.54	$ 3.38	$ 3.13
A5 Environmental									
RIDER E [4]	$ 0.82	$ 0.75	$ 0.70	$ 0.64	$ 0.60	$ 0.55	$ 0.57	$ 0.30	$ 0.28
RIDER CCR	$ 0.23	$ 0.08	$ 0.20	$ 0.08	$ 0.01	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources									
INCREMENTAL GENERIC DSM	$ 9.00	$ 9.00	$ 4.00	$ 3.00	$ 3.00	$ 3.00	$ 2.00	$ 2.00	$ 4.00
GENERIC GAS	$ 9.69	$ 9.09	$ 8.56	$ 8.08	$ 7.68	$ 7.28	$ 6.90	$ 6.55	$ 6.19
BRUNSWICK - 2044 RETIREMENT	$ 0.15	$ 0.13	$ 0.13	$ 0.17	$ 0.18	$ 0.16	$ 0.24	$ (0.16)	$ (1.07)
GREENVILLE - 2045 RETIREMENT	$ 0.19	$ 0.20	$ 0.19	$ 0.22	$ 0.22	$ 0.24	$ 0.20	$ 0.36	$ 0.51
LNG - 2045 RETIREMENT	$ 0.06	$ 0.05	$ 0.04	$ 0.04	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.04
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ 0.05	$ 0.05	$ 0.04	$ 0.03	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ (0.12)
CERC GAS CT - 2045 RETIREMENT	$ 0.27	$ 0.24	$ 0.21	$ 0.20	$ 0.18	$ 0.18	$ 0.19	$ 0.24	$ (0.29)
GAS CT GENERIC - 2045 RETIREMENT	$ 0.53	$ 0.46	$ 0.39	$ 0.32	$ 0.26	$ 0.21	$ 0.15	$ 0.10	$ (0.80)
RPS Program-Related Resources									
RIDER RPS [5]	$ 4.00	$ 3.78	$ 3.52	$ 3.20	$ 3.25	$ 3.31	$ 3.36	$ 3.43	$ 2.63
RIDER CE [6]	$ 62.39	$ 66.63	$ 70.36	$ 72.49	$ 75.80	$ 78.59	$ 81.97	$ 83.47	$ 81.61
RIDER CE - FUEL BENEFIT	$ (21.81)	$ (22.02)	$ (23.01)	$ (22.69)	$ (25.24)	$ (30.59)	$ (34.38)	$ (38.01)	$ (41.11)
RIDER CE - REC PROXY VALUE	$ (2.07)	$ (2.13)	$ (2.01)	$ (1.84)	$ (1.61)	$ (1.66)	$ (1.77)	$ (1.88)	$ (1.90)
RIDER CE - CAPACITY OFFSET	$ (4.47)	$ (5.37)	$ (6.30)	$ (7.16)	$ (7.62)	$ (8.09)	$ (8.51)	$ (8.88)	$ (8.54)
TOTAL RIDER CE	**$ 34.04**	**$ 37.10**	**$ 39.04**	**$ 40.80**	**$ 41.33**	**$ 38.24**	**$ 37.31**	**$ 34.70**	**$ 30.06**
RIDER OSW [7]	$ 14.95	$ 14.42	$ 14.24	$ 14.66	$ 16.09	$ 18.37	$ 20.62	$ 21.53	$ 25.48
RIDER OSW - FUEL BENEFIT	$ (6.54)	$ (6.51)	$ (6.53)	$ (6.65)	$ (6.95)	$ (7.23)	$ (7.55)	$ (8.75)	$ (14.38)
RIDER OSW - REC PROXY VALUE	$ (0.73)	$ (0.64)	$ (0.56)	$ (0.49)	$ (0.45)	$ (0.43)	$ (0.42)	$ (0.41)	$ (0.43)
RIDER OSW - CAPACITY OFFSET	$ (1.56)	$ (1.56)	$ (1.55)	$ (1.50)	$ (1.44)	$ (1.41)	$ (1.38)	$ (1.30)	$ (1.71)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 6.12**	**$ 5.71**	**$ 5.60**	**$ 6.03**	**$ 7.25**	**$ 9.30**	**$ 11.27**	**$ 11.07**	**$ 8.97**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 65.45	$ 74.51	$ 85.51	$ 97.35	$ 106.49	$ 111.85	$ 115.92	$ 133.56	$ 135.01
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 109.62**	**$ 121.10**	**$ 133.67**	**$ 147.38**	**$ 158.32**	**$ 162.70**	**$ 167.86**	**$ 182.75**	**$ 176.67**
TOTAL	**$ 321.45**	**$ 333.83**	**$ 339.70**	**$ 347.89**	**$ 358.83**	**$ 364.06**	**$ 369.82**	**$ 379.79**	**$ 375.58**
CAGR (2019 BASE)			5.2%						4.4%
CAGR (MAY 2020 BASE)			5.6%						4.7%

[1] Publicly available, annualized tariff rates consistent with the rebu
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all appr
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC
[6] Includes specific Company-owned projects and PPAs proposed in
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the c

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, COMPANY METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 312.72	$ 316.69	$ 326.37	$ 330.61	$ 331.82	$ 335.84	$ 336.24	$ 333.89
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 92.53	$ 128.48	$ 133.57	$ 145.75	$ 156.12	$ 164.45	$ 170.93	$ 176.48	$ 180.95
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 178.08	$ 209.66	$ 197.21	$ 193.31	$ 198.60	$ 212.92	$ 224.92	$ 236.38	$ 243.80
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 17.44	$ 18.29	$ 17.80	$ 16.99	$ 16.58	$ 14.75	$ -	$ -	$ -
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 6.77	$ 6.36	$ 6.96	$ 10.26	$ 11.28	$ 11.55	$ 11.25	$ 11.04	$ 10.74	$ 10.22	$ 9.82
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ 1.56	$ 1.54	$ 1.52	$ 1.49	$ 1.45	$ 1.41	$ 1.38	$ 1.35
Generation Infrastructure																
GENERATION RIDERS [2]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 13.71	$ 17.55	$ 35.96	$ 23.91	$ 29.84	$ 29.87	$ 30.58	$ 30.01	$ 27.98	$ 26.81	$ 26.74
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 6.88	$ 4.46	$ 5.22	$ 15.37	$ 17.90	$ 18.94	$ 22.66	$ 26.69	$ 31.24	$ 33.47	$ 33.46	$ 32.40
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.75	$ 5.42	$ 7.40	$ 10.25	$ 12.38	$ 11.72	$ 11.04	$ 10.34
Distribution Infrastructure [3]																
DISTRIBUTION RIDERS	$ 8.75	$ 5.90	$ 5.90	$ 9.30	$ 15.41	$ 10.63	$ 26.83	$ 26.10	$ 34.30	$ 38.07	$ 41.95	$ 44.57	$ 47.52	$ 44.49	$ 43.41	$ 42.59
A5 Environmental																
RIDER E [4]	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.07	$ 2.68	$ 3.41	$ 5.38	$ 6.01	$ 7.54	$ 7.13	$ 6.17	$ 5.69
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.10	$ 7.10	$ 10.94	$ 14.27	$ 13.70	$ 13.11	$ 12.49	$ 11.87	$ 11.29	$ 10.81
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 26.55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources																
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.00	$ 25.00	$ 32.00	$ 12.00	$ 12.00	$ 11.00	$ 11.00	$ 10.00
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.03	$ 17.61	$ 29.20	$ 39.63	$ 47.76	$ 51.70	$ 61.34
BRUNSWICK - 2044 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.73	$ 0.68	$ 0.77	$ 0.83	$ 0.79	$ 0.72	$ 0.72
GREENVILLE - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.64	$ 0.49	$ 2.23	$ 1.32	$ 0.44	$ 1.16	$ 0.95	$ 1.04
LNG - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.55	$ 0.71	$ 0.65	$ 0.62	$ 0.58	$ 0.52
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.06	$ 0.68	$ 0.61	$ 0.55	$ 0.49
CERC GAS CT - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.72	$ 2.82	$ 2.58	$ 2.33	$ 2.10
GAS CT GENERIC - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.13	$ 5.01	$ 4.50
RPS Program-Related Resources																
RIDER RPS [5]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 46.06	$ 33.82	$ 39.53	$ 48.13	$ 48.15	$ 49.46	$ 49.83	$ 48.40	$ 46.02
RIDER CE [6]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.46	$ 17.97	$ 27.64	$ 54.16	$ 63.19	$ 77.86	$ 93.17	$ 122.24	$ 144.76	$ 160.13	$ 182.99
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.14)	$ (13.98)	$ (18.16)	$ (22.28)	$ (22.51)	$ (29.10)	$ (39.34)	$ (48.58)	$ (57.12)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.11)	$ (4.09)	$ (8.08)	$ (12.14)	$ (12.31)	$ (15.34)	$ (16.43)	$ (15.60)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (1.94)	$ (1.85)	$ (4.16)	$ (5.77)	$ (6.28)	$ (6.60)	$ (6.90)	$ (8.15)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.75**	**$ 10.68**	**$ 15.20**	**$ 32.14**	**$ 39.08**	**$ 43.33**	**$ 52.75**	**$ 74.56**	**$ 83.48**	**$ 88.22**	**$ 102.13**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 60.00	$ 62.30	$ 56.74	$ 54.30	$ 49.36	$ 44.36	$ 45.47	$ 44.12	$ 42.73
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12.19)	$ (31.39)	$ (30.68)	$ (29.39)	$ (28.93)	$ (30.13)	$ (31.82)	$ (31.36)	$ (31.09)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3.94)	$ (14.63)	$ (16.79)	$ (16.39)	$ (15.05)	$ (13.06)	$ (10.83)	$ (8.63)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4.65)	$ (6.64)	$ (8.07)	$ (7.50)	$ (6.25)	$ (5.51)	$ (5.42)	$ (5.80)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 47.81**	**$ 22.32**	**$ 4.78**	**$ 0.04**	**$ (3.46)**	**$ (7.06)**	**$ (4.91)**	**$ (3.49)**	**$ (2.79)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.40	$ 1.16	$ 7.21	$ 16.42	$ 33.10	$ 57.05	$ 87.73	$ 122.15	$ 160.84
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.38**	**$ 74.18**	**$ 110.48**	**$ 89.44**	**$ 90.61**	**$ 107.92**	**$ 130.54**	**$ 174.01**	**$ 216.13**	**$ 255.28**	**$ 306.20**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 669.19**	**$ 628.83**	**$ 637.47**	**$ 757.66**	**$ 883.52**	**$ 910.90**	**$ 977.46**	**$ 1,022.18**	**$ 1,108.68**	**$ 1,164.29**	**$ 1,221.01**	**$ 1,285.28**
CAGR (2019 BASE)																
CAGR (MAY 2020 BASE)																

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, COMPANY METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 324.86	$ 329.84	$ 329.16	$ 330.93	$ 332.59	$ 332.07	$ 335.72	$ 352.07	$ 351.41	$ 361.14	$ 374.40	$ 378.13
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 182.93	$ 183.20	$ 183.70	$ 183.55	$ 183.65	$ 183.80	$ 179.50	$ 174.92	$ 170.63	$ 166.58	$ 162.42	$ 158.56
FUEL - RIDER A	$ 242.14	$ 263.32	$ 293.27	$ 296.37	$ 309.19	$ 308.45	$ 289.12	$ 283.06	$ 301.14	$ 310.52	$ 297.41	$ 314.41
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 9.58	$ 9.29	$ 8.97	$ 8.66	$ 8.36	$ 8.09	$ 7.84	$ 7.66	$ 7.45	$ 7.26	$ 7.10	$ 6.91
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1.32	$ 1.30	$ 1.27	$ 1.25	$ 1.23	$ 1.14	$ 1.13	$ 1.13	$ 1.12	$ 1.11	$ 1.11	$ 1.10
Generation Infrastructure												
GENERATION RIDERS [2]	$ 25.01	$ 24.20	$ 23.26	$ 23.15	$ 22.87	$ 20.96	$ 21.07	$ 20.22	$ 19.09	$ 17.84	$ 15.28	$ 15.16
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 30.99	$ 29.55	$ 27.69	$ 25.90	$ 23.96	$ 22.21	$ 20.60	$ 19.24	$ 17.94	$ 16.74	$ 15.64	$ 14.59
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 9.13	$ 8.64	$ 8.17	$ 7.72	$ 7.28	$ 6.89	$ 6.53	$ 6.23	$ 5.93	$ 5.65	$ 5.41	$ 5.21
Distribution Infrastructure [3]												
DISTRIBUTION RIDERS	$ 41.73	$ 40.95	$ 40.00	$ 39.26	$ 38.42	$ 37.67	$ 36.74	$ 35.44	$ 34.34	$ 32.88	$ 16.84	$ 16.03
A5 Environmental												
RIDER E [4]	$ 5.26	$ 4.87	$ 4.50	$ 4.15	$ 3.82	$ 3.54	$ 3.26	$ 3.04	$ 2.80	$ 2.92	$ 1.55	$ 1.43
RIDER CCR	$ 16.81	$ 10.87	$ 10.44	$ 1.38	$ 0.48	$ 1.17	$ 0.50	$ 0.05	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
INCREMENTAL GENERIC DSM	$ 10.00	$ 12.00	$ 36.00	$ 45.00	$ 48.00	$ 19.00	$ 14.00	$ 13.00	$ 13.00	$ 12.00	$ 11.00	$ 18.00
GENERIC GAS	$ 59.41	$ 55.79	$ 52.42	$ 49.25	$ 46.22	$ 43.55	$ 41.08	$ 39.06	$ 37.02	$ 35.10	$ 33.29	$ 31.49
BRUNSWICK - 2044 RETIREMENT	$ 0.66	$ 0.60	$ 0.66	$ 0.77	$ 0.67	$ 0.64	$ 0.89	$ 0.92	$ 0.79	$ 1.24	$ (0.83)	$ (5.45)
GREENVILLE - 2045 RETIREMENT	$ 0.98	$ 0.92	$ 0.80	$ 0.95	$ 1.03	$ 0.95	$ 1.11	$ 1.11	$ 1.22	$ 1.03	$ 1.85	$ 2.60
LNG - 2045 RETIREMENT	$ 0.45	$ 0.40	$ 0.35	$ 0.30	$ 0.25	$ 0.22	$ 0.19	$ 0.16	$ 0.15	$ 0.14	$ 0.17	$ 0.19
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ 0.43	$ 0.38	$ 0.32	$ 0.28	$ 0.23	$ 0.19	$ 0.15	$ 0.11	$ 0.08	$ 0.05	$ 0.04	$ (0.62)
CERC GAS CT - 2045 RETIREMENT	$ 1.89	$ 1.69	$ 1.52	$ 1.36	$ 1.21	$ 1.09	$ 0.99	$ 0.93	$ 0.91	$ 0.97	$ 1.22	$ (1.48)
GAS CT GENERIC - 2045 RETIREMENT	$ 4.00	$ 3.54	$ 3.11	$ 2.70	$ 2.32	$ 1.96	$ 1.64	$ 1.34	$ 1.05	$ 0.78	$ 0.52	$ (4.04)
RPS Program-Related Resources												
RIDER RPS [5]	$ 39.18	$ 26.16	$ 25.00	$ 24.01	$ 22.67	$ 21.14	$ 19.19	$ 19.48	$ 19.86	$ 20.16	$ 20.56	$ 15.78
RIDER CE [6]	$ 215.50	$ 248.51	$ 290.45	$ 329.59	$ 351.59	$ 370.91	$ 381.89	$ 400.24	$ 416.55	$ 436.04	$ 444.75	$ 435.19
RIDER CE - FUEL BENEFIT	$ (73.76)	$ (88.72)	$ (109.19)	$ (130.87)	$ (132.14)	$ (138.06)	$ (136.12)	$ (151.42)	$ (183.55)	$ (206.27)	$ (228.05)	$ (246.67)
RIDER CE - REC PROXY VALUE	$ (13.94)	$ (13.67)	$ (11.48)	$ (12.40)	$ (12.80)	$ (12.05)	$ (11.06)	$ (9.65)	$ (9.98)	$ (10.64)	$ (11.29)	$ (11.39)
RIDER CE - CAPACITY OFFSET	$ (10.67)	$ (13.76)	$ (17.96)	$ (22.86)	$ (27.51)	$ (32.23)	$ (36.62)	$ (39.01)	$ (41.42)	$ (43.58)	$ (45.47)	$ (43.73)
TOTAL RIDER CE	**$ 117.14**	**$ 132.36**	**$ 151.82**	**$ 163.46**	**$ 179.15**	**$ 188.57**	**$ 198.08**	**$ 200.17**	**$ 181.60**	**$ 175.55**	**$ 159.94**	**$ 133.40**
RIDER OSW [7]	$ 45.38	$ 58.00	$ 81.92	$ 76.06	$ 73.37	$ 72.50	$ 74.66	$ 81.88	$ 93.51	$ 104.99	$ 109.61	$ 129.79
RIDER OSW - FUEL BENEFIT	$ (30.56)	$ (31.60)	$ (39.49)	$ (39.23)	$ (39.03)	$ (39.19)	$ (39.87)	$ (41.70)	$ (43.37)	$ (45.32)	$ (52.48)	$ (86.27)
RIDER OSW - REC PROXY VALUE	$ (6.56)	$ (4.62)	$ (3.83)	$ (4.35)	$ (3.84)	$ (3.37)	$ (2.93)	$ (2.68)	$ (2.59)	$ (2.52)	$ (2.45)	$ (2.56)
RIDER OSW - CAPACITY OFFSET	$ (5.99)	$ (6.00)	$ (7.18)	$ (7.96)	$ (7.95)	$ (7.91)	$ (7.64)	$ (7.33)	$ (7.18)	$ (7.01)	$ (6.63)	$ (8.69)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 2.26**	**$ 15.77**	**$ 31.42**	**$ 24.52**	**$ 22.55**	**$ 22.03**	**$ 24.22**	**$ 30.17**	**$ 40.36**	**$ 50.14**	**$ 48.05**	**$ 32.26**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 213.13	$ 251.93	$ 291.22	$ 332.72	$ 378.80	$ 434.80	$ 495.01	$ 541.53	$ 568.76	$ 589.54	$ 679.29	$ 686.67
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 371.71**	**$ 426.22**	**$ 499.46**	**$ 544.72**	**$ 603.17**	**$ 666.54**	**$ 736.50**	**$ 791.35**	**$ 810.59**	**$ 835.39**	**$ 907.84**	**$ 868.10**
TOTAL	**$ 1,339.28**	**$ 1,407.56**	**$ 1,525.07**	**$ 1,567.66**	**$ 1,634.95**	**$ 1,660.13**	**$ 1,698.56**	**$ 1,751.04**	**$ 1,776.64**	**$ 1,809.33**	**$ 1,852.26**	**$ 1,820.29**
CAGR (2019 BASE)		5.8%				5.5%						4.5%
CAGR (MAY 2020 BASE)		6.4%				6.0%						4.9%

[1] Publicly available, annualized tariff rates consistent with the rebutta
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and Lł
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approv
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC pı
[6] Includes specific Company-owned projects and PPAs proposed in 2C
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the ou

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, COMPANY METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029
DISTRIBUTION & GENERATION (BASE) [1]	131,196.69	131,196.69	131,196.69	131,196.69	127,019.69	127,019.69	122,333.63	123,780.20	151,307.33	143,305.96	148,489.00	150,045.69
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	-	-	-	-	(1,597.09)	(1,464.00)	-	-	-	-	-	-
TRANSMISSION - RIDER T	37,760.00	37,760.00	42,270.00	45,260.00	35,280.00	47,770.00	60,900.00	63,540.00	78,320.00	74,510.00	81,310.00	87,100.00
FUEL - RIDER A	139,524.00	104,142.00	102,126.00	122,688.00	212,274.00	171,522.00	124,410.00	178,080.00	209,664.00	197,214.00	193,308.00	198,600.00
FUEL SECURITIZATION	-	-	-	-	-	-	20,226.00	17,436.00	18,288.00	17,802.00	16,992.00	16,578.00
DSM	150.00	150.00	144.00	60.00	102.00	168.00	330.00	570.00	1,050.00	1,530.00	1,602.00	1,656.00
RIDER PIPP - UNIVERSAL SERVICE FEE	-	-	-	162.00	162.00	4,392.00	-	-	1,562.82	1,541.03	1,515.31	1,485.05
Generation Infrastructure												
GENERATION RIDERS [2]	36,670.00	34,070.00	33,750.00	34,570.00	36,660.00	4,054.82	8,682.98	19,100.00	14,540.00	19,650.00	19,710.00	20,180.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	-	-	-	-	4,000.47	2,030.00	3,110.00	8,370.00	10,890.00	12,480.00	14,950.00	17,620.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	-	-	-	-	-	-	-	-	1,670.00	3,570.00	4,880.00	6,760.00
Distribution Infrastructure [3]												
DISTRIBUTION RIDERS	-	-	-	20.00	1,290.00	510.00	2,900.00	1,260.00	1,790.00	1,910.00	2,030.00	2,090.00
A5 Environmental												
RIDER E [4]	5,560.00	5,560.00	4,300.00	3,140.00	4,860.00	4,440.00	3,260.00	1,630.00	1,630.00	2,250.00	3,550.00	3,970.00
RIDER CCR	-	-	-	17,670.00	17,730.00	14,256.00	7,098.00	7,098.00	10,938.00	14,274.00	13,704.00	13,110.00
RIDER RGGI	-	-	-	14,358.00	-	26,550.00	-	-	-	-	-	-
Additional Resources												
INCREMENTAL GENERIC DSM	-	-	-	-	-	-	-	-	-	-	-	-
GENERIC GAS	-	-	-	-	-	-	-	-	-	3,980.00	11,620.00	19,270.00
BRUNSWICK - 2044 RETIREMENT	-	-	-	-	-	-	-	-	-	480.00	450.00	510.00
GREENVILLE - 2045 RETIREMENT	-	-	-	-	-	-	-	-	390.00	320.00	1,470.00	870.00
LNG - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	360.00	470.00
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	-
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	40.00
CERC GAS CT - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	1,130.00
GAS CT GENERIC - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	-
RPS Program-Related Resources												
RIDER RPS [5]	-	-	-	1,092.00	10,860.00	7,896.00	28,134.00	46,056.00	33,822.00	39,534.00	48,126.00	48,150.00
RIDER CE [6]	-	-	-	480.00	5,002.00	7,720.00	11,120.00	14,970.00	23,284.00	43,038.00	54,578.00	64,672.00
RIDER CE - FUEL BENEFIT	-	-	-	-	(2,286.00)	(6,102.00)	(7,290.00)	(7,830.00)	(10,230.00)	(18,162.00)	(22,284.00)	(22,506.00)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(4,464.00)	(4,092.00)	(8,082.00)	(12,138.00)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(80.00)	(74.00)	-	(2,180.00)	(800.00)	(1,220.00)	(2,720.00)	(3,750.00)
TOTAL RIDER CE	**-**	**-**	**-**	**480.00**	**2,636.00**	**1,544.00**	**3,830.00**	**4,960.00**	**7,790.00**	**19,564.00**	**21,492.00**	**26,278.00**
RIDER OSW [7]	-	-	-	-	3,470.00	10,780.00	20,750.00	33,590.00	35,100.00	32,680.00	31,310.00	28,480.00
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	(13,284.00)	(33,480.00)	(30,684.00)	(29,394.00)	(28,932.00)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	(4,206.00)	(14,628.00)	(16,794.00)	(16,392.00)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	(2,620.00)	(3,830.00)	(4,650.00)	(4,330.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**3,470.00**	**10,780.00**	**20,750.00**	**20,306.00**	**(5,206.00)**	**(16,462.00)**	**(19,528.00)**	**(21,174.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	-	-	-	-	-	-	-	750.00	710.00	4,750.00	10,830.00	21,840.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**1,572.00**	**16,966.00**	**20,220.00**	**52,714.00**	**72,072.00**	**37,116.00**	**47,386.00**	**60,920.00**	**75,094.00**
TOTAL	**350,860.69**	**312,878.69**	**313,786.69**	**370,696.69**	**454,747.07**	**421,468.51**	**405,964.61**	**492,936.20**	**539,156.15**	**542,202.99**	**576,860.31**	**616,578.74**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, COMPANY METHODOLOGY

LARGE GEN

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041
DISTRIBUTION & GENERATION (BASE) [1]	$ 149,586.32	$ 150,951.16	$ 149,900.50	$ 147,004.63	$ 139,663.84	$ 141,558.43	$ 139,678.72	$ 139,385.01	$ 138,997.63	$ 137,126.89	$ 137,993.15	$ 147,226.73
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 91,740.00	$ 95,360.00	$ 98,450.00	$ 100,950.00	$ 102,050.00	$ 102,200.00	$ 102,480.00	$ 102,400.00	$ 102,450.00	$ 102,540.00	$ 100,140.00	$ 97,580.00
FUEL - RIDER A	$ 212,922.00	$ 224,916.00	$ 236,376.00	$ 243,798.00	$ 242,136.00	$ 263,322.00	$ 293,274.00	$ 296,370.00	$ 309,186.00	$ 308,454.00	$ 289,122.00	$ 283,056.00
FUEL SECURITIZATION	$ 14,754.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,602.00	$ 1,548.00	$ 1,416.00	$ 1,368.00	$ 1,356.00	$ 1,326.00	$ 1,284.00	$ 1,242.00	$ 1,194.00	$ 1,158.00	$ 1,122.00	$ 1,098.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1,448.96	$ 1,414.60	$ 1,379.13	$ 1,350.56	$ 1,322.84	$ 1,296.03	$ 1,268.22	$ 1,247.84	$ 1,230.34	$ 1,142.70	$ 1,133.41	$ 1,126.37
Generation Infrastructure												
GENERATION RIDERS [2]	$ 19,820.00	$ 18,490.00	$ 17,730.00	$ 17,660.00	$ 16,540.00	$ 16,000.00	$ 15,380.00	$ 15,280.00	$ 15,130.00	$ 13,890.00	$ 13,940.00	$ 13,370.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 20,620.00	$ 22,110.00	$ 22,100.00	$ 21,410.00	$ 20,480.00	$ 19,540.00	$ 18,310.00	$ 17,140.00	$ 15,850.00	$ 14,700.00	$ 13,630.00	$ 12,740.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 8,170.00	$ 7,740.00	$ 7,290.00	$ 6,830.00	$ 6,040.00	$ 5,710.00	$ 5,400.00	$ 5,110.00	$ 4,820.00	$ 4,560.00	$ 4,320.00	$ 4,120.00
Distribution Infrastructure [3]												
DISTRIBUTION RIDERS	$ 2,020.00	$ 1,860.00	$ 1,680.00	$ 1,560.00	$ 1,450.00	$ 1,340.00	$ 1,240.00	$ 1,140.00	$ 1,050.00	$ 980.00	$ 910.00	$ 810.00
A5 Environmental												
RIDER E [4]	$ 4,960.00	$ 4,700.00	$ 4,090.00	$ 3,760.00	$ 3,470.00	$ 3,220.00	$ 2,970.00	$ 2,740.00	$ 2,530.00	$ 2,340.00	$ 2,170.00	$ 2,010.00
RIDER CCR	$ 12,486.00	$ 11,874.00	$ 11,292.00	$ 10,812.00	$ 16,806.00	$ 10,866.00	$ 10,440.00	$ 1,380.00	$ 480.00	$ 1,170.00	$ 498.00	$ 48.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 26,160.00	$ 31,540.00	$ 34,150.00	$ 40,530.00	$ 39,260.00	$ 36,890.00	$ 34,670.00	$ 32,590.00	$ 30,580.00	$ 28,830.00	$ 27,200.00	$ 25,870.00
BRUNSWICK - 2044 RETIREMENT	$ 550.00	$ 520.00	$ 470.00	$ 470.00	$ 430.00	$ 400.00	$ 440.00	$ 510.00	$ 440.00	$ 420.00	$ 590.00	$ 610.00
GREENVILLE - 2045 RETIREMENT	$ 290.00	$ 760.00	$ 630.00	$ 690.00	$ 650.00	$ 610.00	$ 530.00	$ 630.00	$ 680.00	$ 630.00	$ 740.00	$ 740.00
LNG - 2045 RETIREMENT	$ 430.00	$ 410.00	$ 380.00	$ 340.00	$ 300.00	$ 260.00	$ 230.00	$ 200.00	$ 170.00	$ 140.00	$ 120.00	$ 110.00
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ 450.00	$ 410.00	$ 360.00	$ 320.00	$ 280.00	$ 250.00	$ 210.00	$ 180.00	$ 150.00	$ 130.00	$ 100.00	$ 80.00
CERC GAS CT - 2045 RETIREMENT	$ 1,860.00	$ 1,700.00	$ 1,540.00	$ 1,390.00	$ 1,250.00	$ 1,120.00	$ 1,000.00	$ 900.00	$ 800.00	$ 720.00	$ 660.00	$ 620.00
GAS CT GENERIC - 2045 RETIREMENT	$ -	$ 2,070.00	$ 3,310.00	$ 2,970.00	$ 2,640.00	$ 2,340.00	$ 2,050.00	$ 1,790.00	$ 1,530.00	$ 1,300.00	$ 1,080.00	$ 890.00
RPS Program-Related Resources												
RIDER RPS [5]	$ 49,458.00	$ 49,830.00	$ 48,396.00	$ 46,020.00	$ 39,180.00	$ 26,160.00	$ 25,002.00	$ 24,012.00	$ 22,674.00	$ 21,144.00	$ 19,194.00	$ 19,476.00
RIDER CE [6]	$ 84,578.00	$ 100,076.00	$ 110,842.00	$ 126,668.00	$ 152,618.00	$ 178,636.00	$ 210,270.00	$ 240,198.00	$ 255,354.00	$ 268,552.00	$ 275,866.00	$ 291,224.00
RIDER CE - FUEL BENEFIT	$ (29,100.00)	$ (39,342.00)	$ (48,582.00)	$ (57,120.00)	$ (73,758.00)	$ (88,716.00)	$ (109,188.00)	$ (130,872.00)	$ (132,138.00)	$ (138,060.00)	$ (136,122.00)	$ (151,422.00)
RIDER CE - REC PROXY VALUE	$ (12,306.00)	$ (15,336.00)	$ (16,434.00)	$ (15,600.00)	$ (13,938.00)	$ (13,674.00)	$ (11,484.00)	$ (12,402.00)	$ (12,798.00)	$ (12,048.00)	$ (11,064.00)	$ (9,648.00)
RIDER CE - CAPACITY OFFSET	$ (4,120.00)	$ (4,310.00)	$ (4,530.00)	$ (5,320.00)	$ (6,990.00)	$ (9,010.00)	$ (11,760.00)	$ (15,000.00)	$ (18,010.00)	$ (21,140.00)	$ (24,030.00)	$ (25,590.00)
TOTAL RIDER CE	**$ 39,052.00**	**$ 41,088.00**	**$ 41,296.00**	**$ 48,628.00**	**$ 57,932.00**	**$ 67,236.00**	**$ 77,838.00**	**$ 81,924.00**	**$ 92,408.00**	**$ 97,304.00**	**$ 104,650.00**	**$ 104,564.00**
RIDER OSW [7]	$ 25,610.00	$ 26,280.00	$ 25,520.00	$ 24,730.00	$ 26,270.00	$ 33,610.00	$ 47,500.00	$ 44,130.00	$ 42,590.00	$ 42,110.00	$ 43,390.00	$ 47,610.00
RIDER OSW - FUEL BENEFIT	$ (30,126.00)	$ (31,818.00)	$ (31,362.00)	$ (31,092.00)	$ (30,564.00)	$ (31,602.00)	$ (39,486.00)	$ (39,228.00)	$ (39,030.00)	$ (39,186.00)	$ (39,870.00)	$ (41,700.00)
RIDER OSW - REC PROXY VALUE	$ (15,054.00)	$ (13,056.00)	$ (10,830.00)	$ (8,628.00)	$ (6,564.00)	$ (4,620.00)	$ (3,828.00)	$ (4,350.00)	$ (3,840.00)	$ (3,372.00)	$ (2,934.00)	$ (2,682.00)
RIDER OSW - CAPACITY OFFSET	$ (3,610.00)	$ (3,180.00)	$ (3,140.00)	$ (3,350.00)	$ (3,470.00)	$ (3,480.00)	$ (4,160.00)	$ (4,620.00)	$ (4,610.00)	$ (4,590.00)	$ (4,440.00)	$ (4,260.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (23,180.00)**	**$ (21,774.00)**	**$ (19,812.00)**	**$ (18,340.00)**	**$ (14,328.00)**	**$ (6,092.00)**	**$ 26.00**	**$ (4,068.00)**	**$ (4,890.00)**	**$ (5,038.00)**	**$ (3,854.00)**	**$ (1,032.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 37,650.00	$ 57,930.00	$ 80,690.00	$ 106,280.00	$ 140,860.00	$ 166,570.00	$ 192,600.00	$ 220,120.00	$ 250,640.00	$ 287,800.00	$ 327,730.00	$ 358,590.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 102,980.00**	**$ 127,074.00**	**$ 150,570.00**	**$ 182,588.00**	**$ 223,644.00**	**$ 253,874.00**	**$ 295,466.00**	**$ 321,988.00**	**$ 360,832.00**	**$ 401,210.00**	**$ 447,720.00**	**$ 481,598.00**
TOTAL	**$ 672,849.28**	**$ 705,447.76**	**$ 743,113.63**	**$ 785,801.19**	**$ 819,768.68**	**$ 862,122.46**	**$ 926,320.94**	**$ 942,222.85**	**$ 988,099.97**	**$ 1,021,441.59**	**$ 1,043,188.56**	**$ 1,073,703.10**
CAGR (2019 BASE)						5.8%				5.5%		
CAGR (MAY 2020 BASE)						6.7%				6.2%		

[1] Publicly available, annualized tariff rates consistent with t
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US
[3] Consolidated Distribution Riders GT, U, and RBB. Includes
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, a
[6] Includes specific Company-owned projects and PPAs prop
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate REC

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

ERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, COMPANY METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 145,177.98	$ 149,977.26	$ 157,084.92	$ 157,841.33
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 95,190.00	$ 92,930.00	$ 90,610.00	$ 88,450.00
FUEL - RIDER A	$ 301,140.00	$ 310,524.00	$ 297,414.00	$ 314,406.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -
DSM	$ 1,068.00	$ -	$ 1,020.00	$ 990.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1,120.49	$ 1,113.12	$ 1,107.45	$ 1,103.00
Generation Infrastructure				
GENERATION RIDERS [2]	$ 12,620.00	$ 11,800.00	$ 10,120.00	$ 10,050.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 11,880.00	$ 11,090.00	$ 10,360.00	$ 9,670.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 3,930.00	$ 3,740.00	$ 3,580.00	$ 3,450.00
Distribution Infrastructure [3]				
DISTRIBUTION RIDERS	$ 750.00	$ 660.00	$ 590.00	$ 550.00
A5 Environmental				
RIDER E [4]	$ 1,860.00	$ 1,940.00	$ 1,020.00	$ 940.00
RIDER CCR	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -
Additional Resources				
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -
GENERIC GAS	$ 24,510.00	$ 23,250.00	$ 22,060.00	$ 20,860.00
BRUNSWICK - 2044 RETIREMENT	$ 520.00	$ 820.00	$ (550.00)	$ (3,610.00)
GREENVILLE - 2045 RETIREMENT	$ 810.00	$ 680.00	$ 1,230.00	$ 1,720.00
LNG - 2045 RETIREMENT	$ 100.00	$ 100.00	$ 110.00	$ 120.00
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ (10.00)	$ (10.00)	$ (10.00)	$ (10.00)
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ 50.00	$ 30.00	$ 20.00	$ (410.00)
CERC GAS CT - 2045 RETIREMENT	$ 600.00	$ 640.00	$ 810.00	$ (980.00)
GAS CT GENERIC - 2045 RETIREMENT	$ 700.00	$ 520.00	$ 350.00	$ (2,680.00)
RPS Program-Related Resources				
RIDER RPS [5]	$ 19,860.00	$ 20,160.00	$ 20,562.00	$ 15,780.00
RIDER CE [6]	$ 306,694.00	$ 112,128.00	$ 332,760.00	$ 326,366.00
RIDER CE - FUEL BENEFIT	$ (183,546.00)	$ (206,274.00)	$ (228,054.00)	$ (246,672.00)
RIDER CE - REC PROXY VALUE	$ (9,984.00)	$ (10,644.00)	$ (11,292.00)	$ (11,394.00)
RIDER CE - CAPACITY OFFSET	$ (27,170.00)	$ -	$ (29,820.00)	$ (28,670.00)
TOTAL RIDER CE	**$ 85,994.00**	**$ (104,790.00)**	**$ 63,594.00**	**$ 39,630.00**
RIDER OSW [7]	$ 54,380.00	$ -	$ 63,810.00	$ 75,580.00
RIDER OSW - FUEL BENEFIT	$ (43,374.00)	$ (45,318.00)	$ (52,482.00)	$ (86,274.00)
RIDER OSW - REC PROXY VALUE	$ (2,592.00)	$ (2,520.00)	$ (2,454.00)	$ (2,562.00)
RIDER OSW - CAPACITY OFFSET	$ (4,170.00)	$ -	$ (3,860.00)	$ (5,060.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 4,244.00**	**$ (47,838.00)**	**$ 5,014.00**	**$ (18,316.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 376,640.00	$ 390,490.00	$ 450,010.00	$ 454,950.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 486,738.00**	**$ 258,022.00**	**$ 539,180.00**	**$ 492,044.00**
TOTAL	**$ 1,088,754.47**	**$ 867,826.38**	**$ 1,136,106.37**	**$ 1,094,504.33**
CAGR (2019 BASE)				4.5%
CAGR (MAY 2020 BASE)				5.0%

[1] Publicly available, annualized tariff rates consistent with t
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US
[3] Consolidated Distribution Riders GT, U, and RBB. Includes
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, a
[6] Includes specific Company-owned projects and PPAs prop
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RE(

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - LEAST COST
VCEA COMPLIANT WITHOUT EPA, COMPANY

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 60.93	$ 60.93	$ 60.71	$ 60.71	$ 73.57	$ 75.80	$ 77.97	$ 79.06	$ 79.57	$ 80.93	$ 81.21	$ 80.98	$ 80.66	$ 81.75	$ 82.34
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (0.47)	$ (0.43)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	$ 12.91	$ 15.58	$ 19.40	$ 21.49	$ 23.43	$ 27.67	$ 30.49	$ 33.10	$ 35.31	$ 36.77	$ 37.90	$ 38.89	$ 39.80	$ 40.08	$ 40.00
FUEL - RIDER A	$ 23.25	$ 17.36	$ 17.02	$ 20.45	$ 35.38	$ 28.59	$ 20.74	$ 29.68	$ 34.94	$ 32.86	$ 32.16	$ 31.42	$ 32.48	$ 31.96	$ 32.21	$ 32.88	$ 32.97	$ 34.89	$ 37.04
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.37	$ 2.91	$ 3.05	$ 2.97	$ 2.83	$ 2.76	$ 2.46	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1.13	$ 1.13	$ 1.47	$ 1.31	$ 1.60	$ 1.84	$ 1.55	$ 1.57	$ 2.04	$ 2.22	$ 2.27	$ 2.22	$ 2.17	$ 2.11	$ 2.01	$ 1.93	$ 1.88	$ 1.83	$ 1.76
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 0.03	$ 0.03	$ 0.73	$ -	$ -	$ 0.26	$ 0.26	$ 0.25	$ 0.25	$ 0.24	$ 0.24	$ 0.23	$ 0.23	$ 0.22	$ 0.22	$ 0.21
Generation Infrastructure																			
GENERATION RIDERS [2]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	$ 14.51	$ 6.67	$ 6.57	$ 7.57	$ 5.10	$ 5.87	$ 5.88	$ 6.00	$ 5.86	$ 5.45	$ 5.22	$ 5.17	$ 4.81	$ 4.64	$ 4.44
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 2.07	$ 0.93	$ 1.29	$ 3.48	$ 3.82	$ 3.73	$ 4.46	$ 5.25	$ 6.15	$ 6.59	$ 6.58	$ 6.38	$ 6.10	$ 5.81	$ 5.45
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.59	$ 1.07	$ 1.46	$ 2.02	$ 2.44	$ 2.31	$ 2.17	$ 2.04	$ 1.80	$ 1.70	$ 1.61
Distribution Infrastructure [3]																			
DISTRIBUTION RIDERS	$ 1.84	$ 1.40	$ 1.40	$ 2.16	$ 3.84	$ 2.53	$ 7.81	$ 6.77	$ 9.04	$ 10.00	$ 10.95	$ 11.55	$ 12.19	$ 11.28	$ 10.87	$ 10.49	$ 10.10	$ 9.70	$ 9.32
A5 Environmental																			
RIDER E	$ 1.99	$ 1.99	$ 1.67	$ 1.25	$ 1.95	$ 2.03	$ 1.35	$ 0.64	$ 0.57	$ 0.61	$ 0.55	$ 0.65	$ 0.67	$ 0.62	$ 0.47	$ 0.42	$ 0.39	$ 0.36	$ 0.33
RIDER CCR	$ -	$ -	$ -	$ 2.95	$ 2.96	$ 2.38	$ 1.18	$ 1.18	$ 1.82	$ 2.38	$ 2.28	$ 2.19	$ 2.08	$ 1.98	$ 1.88	$ 1.80	$ 2.80	$ 1.81	$ 1.74
RIDER RGGI	$ -	$ -	$ -	$ 2.39	$ -	$ 4.43	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources																			
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.00	$ 5.00	$ 6.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 7.00
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.19	$ 3.47	$ 5.92	$ 8.63	$ 11.68	$ 14.90	$ 21.40	$ 23.52	$ 24.26	$ 23.51
RPS Program-Related Resources																			
RIDER RPS [4]	$ -	$ -	$ -	$ 0.18	$ 1.81	$ 1.32	$ 4.69	$ 7.68	$ 5.64	$ 6.59	$ 8.33	$ 8.70	$ 9.32	$ 10.13	$ 10.56	$ 10.46	$ 10.42	$ 10.78	$ 10.84
RIDER CE [5]	$ -	$ -	$ -	$ 0.19	$ 1.67	$ 2.59	$ 4.10	$ 6.17	$ 10.61	$ 12.09	$ 14.76	$ 17.65	$ 23.25	$ 27.81	$ 30.91	$ 33.96	$ 36.95	$ 39.86	$ 42.39
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.38)	$ (1.15)	$ (1.22)	$ (1.55)	$ (2.33)	$ (3.03)	$ (3.68)	$ (3.71)	$ (5.24)	$ (6.50)	$ (7.44)	$ (8.75)	$ (9.70)	$ (10.56)	$ (11.58)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.02)	$ (0.68)	$ (1.35)	$ (2.10)	$ (2.24)	$ (3.22)	$ (3.89)	$ (4.24)	$ (4.28)	$ (4.21)	$ (4.01)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.03)	$ (0.03)	$ -	$ (0.96)	$ (0.38)	$ (0.36)	$ (0.81)	$ (1.13)	$ (1.22)	$ (1.34)	$ (1.46)	$ (1.68)	$ (1.99)	$ (2.25)	$ (2.50)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 1.26**	**$ 1.41**	**$ 2.89**	**$ 3.67**	**$ 6.87**	**$ 8.02**	**$ 8.92**	**$ 10.71**	**$ 14.55**	**$ 16.76**	**$ 18.12**	**$ 19.29**	**$ 20.99**	**$ 22.84**	**$ 24.30**
RIDER OSW [6]	$ -	$ -	$ -	$ -	$ 1.45	$ 4.74	$ 8.63	$ 13.57	$ 12.40	$ 11.17	$ 10.69	$ 9.71	$ 8.73	$ 8.94	$ 9.24	$ 9.03	$ 10.24	$ 13.99	$ 20.78
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.34)	$ (5.28)	$ (5.10)	$ (4.86)	$ (4.75)	$ (4.54)	$ (4.25)	$ (4.05)	$ (3.95)	$ (3.85)	$ (3.92)	$ (4.93)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.66)	$ (2.44)	$ (2.87)	$ (2.92)	$ (2.80)	$ (2.59)	$ (2.35)	$ (2.07)	$ (1.79)	$ (1.52)	$ (1.37)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.93)	$ (1.31)	$ (1.59)	$ (1.48)	$ (1.26)	$ (1.22)	$ (1.22)	$ (1.25)	$ (1.21)	$ (1.14)	$ (1.36)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.45**	**$ 4.74**	**$ 8.63**	**$ 11.23**	**$ 5.53**	**$ 2.32**	**$ 1.36**	**$ 0.57**	**$ 0.13**	**$ 0.89**	**$ 1.62**	**$ 1.76**	**$ 3.39**	**$ 7.41**	**$ 13.12**
NUCLEAR SMALL MODULAR REACTORS [7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.30	$ 0.25	$ 0.08	$ 0.05	$ 0.05	$ -	$ -	$ -	$ -	$ 0.14	$ 0.38	$ 0.92
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 4.52**	**$ 7.47**	**$ 16.21**	**$ 22.87**	**$ 18.29**	**$ 17.02**	**$ 18.66**	**$ 20.02**	**$ 24.00**	**$ 27.78**	**$ 30.30**	**$ 31.51**	**$ 34.94**	**$ 41.42**	**$ 49.18**
TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.54**	**$ 122.72**	**$ 140.22**	**$ 133.66**	**$ 140.17**	**$ 158.86**	**$ 180.51**	**$ 188.64**	**$ 199.68**	**$ 204.41**	**$ 216.24**	**$ 221.69**	**$ 227.97**	**$ 236.11**	**$ 241.98**	**$ 250.47**	**$ 263.92**
CAGR (2019 BASE)																		4.56%	
CAGR (MAY 2020 BASE)																		5.03%	

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[5] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - LEAST COST
VCEA COMPLIANT WITHOUT EPA, COMPANY

RESIDENTIAL Schedule 1 (1,000 kWh)	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 82.51	$ 82.62	$ 84.70	$ 85.63	$ 87.79	$ 89.06	$ 90.56	$ 91.86	$ 93.35
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 39.95	$ 39.96	$ 39.95	$ 40.18	$ 40.25	$ 40.29	$ 40.31	$ 40.22	$ 40.13
FUEL - RIDER A	$ 37.95	$ 39.05	$ 41.87	$ 44.03	$ 48.62	$ 52.61	$ 56.38	$ 60.89	$ 64.77
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1.70	$ 1.64	$ 1.59	$ 1.54	$ 1.50	$ 1.46	$ 1.43	$ 1.39	$ 1.35
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 0.21	$ 0.21	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.18	$ 0.18
Generation Infrastructure									
GENERATION RIDERS [2]	$ 4.42	$ 4.38	$ 4.02	$ 4.05	$ 3.89	$ 3.67	$ 3.43	$ 2.95	$ 2.97
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 5.10	$ 4.71	$ 4.37	$ 4.05	$ 3.78	$ 3.53	$ 3.29	$ 3.08	$ 2.87
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 1.52	$ 1.43	$ 1.36	$ 1.28	$ 1.23	$ 1.17	$ 1.11	$ 1.06	$ 1.02
Distribution Infrastructure [3]									
DISTRIBUTION RIDERS	$ 8.95	$ 8.58	$ 8.22	$ 7.85	$ 7.38	$ 7.00	$ 6.54	$ 3.38	$ 3.13
A5 Environmental									
RIDER E	$ 0.30	$ 0.28	$ 0.26	$ 0.24	$ 0.22	$ 0.20	$ 0.30	$ 0.08	$ 0.08
RIDER CCR	$ 0.23	$ 0.08	$ 0.20	$ 0.08	$ 0.01	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources									
INCREMENTAL GENERIC DSM	$ 9.00	$ 9.00	$ 4.00	$ 3.00	$ 3.00	$ 3.00	$ 2.00	$ 2.00	$ 4.00
GENERIC GAS	$ 22.61	$ 21.52	$ 20.24	$ 19.07	$ 18.12	$ 17.16	$ 16.27	$ 15.43	$ 14.60
RPS Program-Related Resources									
RIDER RPS [4]	$ 11.85	$ 12.70	$ 13.23	$ 10.92	$ 12.45	$ 14.00	$ 14.62	$ 15.35	$ 16.60
RIDER CE [5]	$ 44.67	$ 45.76	$ 46.34	$ 46.37	$ 46.16	$ 45.10	$ 44.88	$ 44.48	$ 44.26
RIDER CE - FUEL BENEFIT	$ (12.87)	$ (14.42)	$ (16.14)	$ (17.32)	$ (20.34)	$ (24.09)	$ (27.22)	$ (31.66)	$ (34.44)
RIDER CE - REC PROXY VALUE	$ (3.96)	$ (3.81)	$ (3.62)	$ (3.36)	$ (3.02)	$ (2.93)	$ (2.82)	$ (2.68)	$ (2.51)
RIDER CE - CAPACITY OFFSET	$ (2.73)	$ (2.94)	$ (3.09)	$ (3.13)	$ (3.01)	$ (2.88)	$ (2.63)	$ (2.50)	$ (2.30)
TOTAL RIDER CE	**$ 25.11**	**$ 24.60**	**$ 23.49**	**$ 22.56**	**$ 19.79**	**$ 15.19**	**$ 12.21**	**$ 7.64**	**$ 5.01**
RIDER OSW [6]	$ 22.66	$ 24.61	$ 25.17	$ 28.83	$ 26.89	$ 25.34	$ 23.99	$ 22.81	$ 22.02
RIDER OSW - FUEL BENEFIT	$ (4.96)	$ (4.99)	$ (5.69)	$ (9.27)	$ (10.04)	$ (10.88)	$ (11.86)	$ (12.92)	$ (13.72)
RIDER OSW - REC PROXY VALUE	$ (1.55)	$ (1.34)	$ (1.16)	$ (1.06)	$ (1.54)	$ (1.41)	$ (1.28)	$ (1.16)	$ (1.04)
RIDER OSW - CAPACITY OFFSET	$ (1.51)	$ (1.51)	$ (1.51)	$ (2.18)	$ (2.63)	$ (2.62)	$ (2.59)	$ (2.56)	$ (2.52)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 14.65**	**$ 16.78**	**$ 16.81**	**$ 16.31**	**$ 12.67**	**$ 10.43**	**$ 8.25**	**$ 6.17**	**$ 4.74**
NUCLEAR SMALL MODULAR REACTORS [7]	$ 1.85	$ 3.11	$ 4.64	$ 6.21	$ 7.78	$ 9.64	$ 10.32	$ 10.48	$ 9.74
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 53.45**	**$ 57.19**	**$ 58.18**	**$ 56.00**	**$ 52.69**	**$ 49.27**	**$ 45.39**	**$ 39.63**	**$ 36.08**
TOTAL	**$ 267.89**	**$ 270.64**	**$ 269.13**	**$ 267.19**	**$ 268.64**	**$ 268.60**	**$ 267.21**	**$ 262.15**	**$ 264.53**
CAGR (2019 BASE)			4.01%						3.00%
CAGR (MAY 2020 BASE)			4.36%						3.26%

[1] Publicly available, annualized tariff rates consistent with the rebı
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, anc
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all app
[4] Includes the cost of REC purchases, deficiency payments, and RE(
[5] Includes specific Company-owned projects and PPAs proposed in
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - LEAST COST VCEA
COMPLIANT WITHOUT EPA, COMPANY METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032
DISTRIBUTION & GENERATION (BASE) [1]	272.78	272.78	272.78	272.78	266.31	266.31	259.72	264.59	312.72	316.69	326.37	330.61	331.82	337.35	337.37
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	-	-	-	-	(3.27)	(3.00)	-	-	-	-	-	-	-	-	-
TRANSMISSION - RIDER T	76.59	76.59	89.37	70.55	58.84	65.08	90.40	95.33	128.29	133.67	147.29	159.89	170.57	177.65	183.10
FUEL - RIDER A	139.52	104.14	102.13	122.69	212.27	171.52	124.41	178.08	209.65	197.14	192.98	188.53	194.89	191.76	193.28
FUEL SECURITIZATION	-	-	-	-	-	-	20.23	17.44	18.29	17.80	16.99	16.58	14.75	-	-
DSM	5.33	5.33	6.49	6.22	6.42	6.77	6.36	6.96	10.26	11.28	11.55	11.25	11.04	10.74	10.22
RIDER PIPP - UNIVERSAL SERVICE FEE	-	-	-	0.16	0.16	4.39	-	-	1.56	1.54	1.52	1.49	1.45	1.41	1.38
Generation Infrastructure															
GENERATION RIDERS [2]	61.54	58.22	57.99	65.89	59.26	13.71	17.55	35.96	23.91	29.84	29.87	30.49	29.75	27.70	26.50
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	-	-	-	-	6.88	4.46	5.22	15.37	17.90	18.94	22.66	26.69	31.24	33.47	33.46
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	-	-	-	-	-	-	-	-	2.75	5.42	7.40	10.25	12.38	11.72	11.04
Distribution Infrastructure [3]															
DISTRIBUTION RIDERS	8.75	5.90	5.90	9.30	15.41	10.63	26.83	26.10	34.30	38.07	41.95	44.57	47.52	44.49	43.41
A5 Environmental															
RIDER E	9.44	9.44	7.48	5.99	7.76	9.77	5.48	3.07	2.68	3.10	2.81	3.32	3.38	3.16	2.38
RIDER CCR	-	-	-	17.67	17.73	14.26	7.10	7.10	10.94	14.27	13.70	13.11	12.49	11.87	11.29
RIDER RGGI	-	-	-	14.36	-	26.55	-	-	-	-	-	-	-	-	-
Additional Resources															
INCREMENTAL GENERIC DSM	-	-	-	-	-	-	-	-	20.00	25.00	32.00	12.00	12.00	11.00	11.00
GENERIC GAS	-	-	-	-	-	-	-	-	-	6.03	17.65	30.05	43.84	59.33	75.73
RPS Program-Related Resources															
RIDER RPS [4]	-	-	-	1.09	10.86	7.90	28.13	46.06	33.83	39.55	49.97	52.21	55.94	60.78	63.38
RIDER CE [5]	-	-	-	0.92	7.18	14.46	17.97	27.64	54.16	62.57	77.05	91.88	121.65	145.90	162.67
RIDER CE - FUEL BENEFIT	-	-	-	-	(2.29)	(6.57)	(7.29)	(8.14)	(13.98)	(18.17)	(22.08)	(22.26)	(31.45)	(38.99)	(44.62)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(6.11)	(4.09)	(8.08)	(12.59)	(13.42)	(19.29)	(23.35)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.13)	(0.14)	-	(4.29)	(1.94)	(1.85)	(4.16)	(5.77)	(6.25)	(6.82)	(7.48)
TOTAL RIDER CE	**-**	**-**	**-**	**0.92**	**4.76**	**7.75**	**10.68**	**15.20**	**32.14**	**38.45**	**42.72**	**51.25**	**70.53**	**80.79**	**87.23**
RIDER OSW [6]	-	-	-	-	5.80	22.73	35.36	60.00	62.30	56.74	54.30	49.36	44.36	45.47	46.98
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	(12.19)	(31.38)	(30.60)	(29.18)	(28.52)	(27.22)	(25.49)	(24.29)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	(3.94)	(14.62)	(17.23)	(17.50)	(16.79)	(15.53)	(14.11)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	(4.65)	(6.64)	(8.07)	(7.50)	(6.41)	(6.19)	(6.21)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**5.80**	**22.73**	**35.36**	**47.81**	**22.33**	**4.87**	**(0.17)**	**(4.16)**	**(6.06)**	**(1.75)**	**2.37**
NUCLEAR SMALL MODULAR REACTORS [7]	-	-	-	-	-	-	-	1.40	1.16	0.41	0.23	0.23	-	-	-
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**2.01**	**21.42**	**38.38**	**74.18**	**110.48**	**89.45**	**83.29**	**92.75**	**99.53**	**120.41**	**139.82**	**152.98**
TOTAL	**573.95**	**532.40**	**542.13**	**587.62**	**669.19**	**628.83**	**637.47**	**760.47**	**882.70**	**902.09**	**957.49**	**978.36**	**1,037.54**	**1,061.48**	**1,093.13**
CAGR (2019 BASE)															
CAGR (MAY 2020 BASE)															

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[5] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - LEAST COST VCEA COMPLIANT
WITHOUT EPA, COMPANY METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 334.76	$ 331.65	$ 335.69	$ 337.14	$ 336.43	$ 335.41	$ 344.35	$ 347.41	$ 356.66	$ 361.41	$ 367.27	$ 372.06	$ 377.82
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 187.89	$ 192.26	$ 193.61	$ 193.22	$ 193.00	$ 193.04	$ 193.00	$ 194.09	$ 194.42	$ 194.65	$ 194.75	$ 194.32	$ 193.88
FUEL - RIDER A	$ 197.27	$ 197.84	$ 209.32	$ 222.23	$ 227.69	$ 234.27	$ 251.24	$ 264.16	$ 291.69	$ 315.65	$ 338.30	$ 365.35	$ 388.63
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 9.82	$ 9.58	$ 9.29	$ 8.97	$ 8.66	$ 8.36	$ 8.09	$ 7.84	$ 7.66	$ 7.45	$ 7.26	$ 7.10	$ 6.91
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1.35	$ 1.32	$ 1.30	$ 1.27	$ 1.25	$ 1.23	$ 1.14	$ 1.13	$ 1.13	$ 1.12	$ 1.11	$ 1.11	$ 1.10
Generation Infrastructure													
GENERATION RIDERS [2]	$ 26.26	$ 24.46	$ 23.58	$ 22.58	$ 22.48	$ 22.27	$ 20.43	$ 20.61	$ 19.77	$ 18.64	$ 17.45	$ 14.98	$ 15.07
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 32.40	$ 30.99	$ 29.55	$ 27.69	$ 25.90	$ 23.96	$ 22.21	$ 20.60	$ 19.24	$ 17.94	$ 16.74	$ 15.64	$ 14.59
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 10.34	$ 9.13	$ 8.64	$ 8.17	$ 7.72	$ 7.28	$ 6.89	$ 6.53	$ 6.23	$ 5.93	$ 5.65	$ 5.41	$ 5.21
Distribution Infrastructure [3]													
DISTRIBUTION RIDERS	$ 42.59	$ 41.73	$ 40.95	$ 40.00	$ 39.26	$ 38.42	$ 37.67	$ 36.74	$ 35.44	$ 34.34	$ 32.88	$ 16.84	$ 16.03
A5 Environmental													
RIDER E	$ 2.15	$ 1.98	$ 1.83	$ 1.69	$ 1.55	$ 1.42	$ 1.31	$ 1.19	$ 1.10	$ 1.01	$ 1.51	$ 0.43	$ 0.38
RIDER CCR	$ 10.81	$ 16.81	$ 10.87	$ 10.44	$ 1.38	$ 0.48	$ 1.17	$ 0.50	$ 0.05	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources													
INCREMENTAL GENERIC DSM	$ 10.00	$ 10.00	$ 12.00	$ 36.00	$ 45.00	$ 48.00	$ 19.00	$ 14.00	$ 13.00	$ 13.00	$ 12.00	$ 11.00	$ 18.00
GENERIC GAS	$ 108.73	$ 119.50	$ 123.33	$ 119.50	$ 114.91	$ 109.39	$ 102.88	$ 96.97	$ 92.12	$ 87.28	$ 82.75	$ 78.48	$ 74.26
RPS Program-Related Resources													
RIDER RPS [4]	$ 62.77	$ 62.51	$ 64.70	$ 65.05	$ 71.07	$ 76.20	$ 79.38	$ 65.52	$ 74.72	$ 83.99	$ 87.71	$ 92.08	$ 99.57
RIDER CE [5]	$ 179.06	$ 195.08	$ 210.62	$ 224.20	$ 236.50	$ 242.72	$ 246.38	$ 247.72	$ 247.73	$ 243.37	$ 243.29	$ 242.21	$ 241.97
RIDER CE - FUEL BENEFIT	$ (52.51)	$ (58.17)	$ (63.33)	$ (69.45)	$ (77.23)	$ (86.49)	$ (96.83)	$ (103.94)	$ (122.03)	$ (144.55)	$ (163.32)	$ (189.94)	$ (206.62)
RIDER CE - REC PROXY VALUE	$ (25.42)	$ (25.66)	$ (25.25)	$ (24.08)	$ (23.75)	$ (22.85)	$ (21.70)	$ (20.14)	$ (18.10)	$ (17.57)	$ (16.92)	$ (16.10)	$ (15.07)
RIDER CE - CAPACITY OFFSET	$ (8.61)	$ (10.18)	$ (11.53)	$ (12.80)	$ (13.97)	$ (15.04)	$ (15.83)	$ (16.02)	$ (15.41)	$ (14.75)	$ (13.46)	$ (12.77)	$ (11.75)
TOTAL RIDER CE	**$ 92.53**	**$ 101.08**	**$ 110.51**	**$ 117.86**	**$ 121.55**	**$ 118.33**	**$ 112.03**	**$ 107.62**	**$ 92.19**	**$ 66.50**	**$ 49.60**	**$ 23.40**	**$ 8.53**
RIDER OSW [6]	$ 45.91	$ 52.07	$ 71.18	$ 105.73	$ 115.30	$ 125.26	$ 128.09	$ 146.76	$ 136.87	$ 128.99	$ 122.13	$ 116.13	$ 112.16
RIDER OSW - FUEL BENEFIT	$ (23.69)	$ (23.12)	$ (23.51)	$ (29.59)	$ (29.74)	$ (29.91)	$ (34.12)	$ (55.64)	$ (60.26)	$ (65.27)	$ (71.18)	$ (77.53)	$ (82.34)
RIDER OSW - REC PROXY VALUE	$ (12.41)	$ (10.71)	$ (9.13)	$ (8.24)	$ (9.28)	$ (8.06)	$ (6.94)	$ (6.38)	$ (9.24)	$ (8.45)	$ (7.69)	$ (6.97)	$ (6.25)
RIDER OSW - CAPACITY OFFSET	$ (6.38)	$ (6.16)	$ (5.79)	$ (6.90)	$ (7.67)	$ (7.67)	$ (7.69)	$ (11.10)	$ (13.42)	$ (13.31)	$ (13.20)	$ (13.01)	$ (12.85)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 3.43**	**$ 12.08**	**$ 32.75**	**$ 61.00**	**$ 68.61**	**$ 79.62**	**$ 79.36**	**$ 73.64**	**$ 53.95**	**$ 41.95**	**$ 30.05**	**$ 18.62**	**$ 10.72**
NUCLEAR SMALL MODULAR REACTORS [7]	$ -	$ 0.68	$ 1.95	$ 4.67	$ 9.38	$ 15.80	$ 23.61	$ 31.58	$ 39.55	$ 49.01	$ 52.48	$ 53.30	$ 49.52
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 158.73**	**$ 176.36**	**$ 209.90**	**$ 248.58**	**$ 270.61**	**$ 289.96**	**$ 294.38**	**$ 278.36**	**$ 260.41**	**$ 241.46**	**$ 219.84**	**$ 187.40**	**$ 168.34**
TOTAL	**$ 1,133.10**	**$ 1,163.61**	**$ 1,209.86**	**$ 1,277.47**	**$ 1,295.84**	**$ 1,313.47**	**$ 1,303.77**	**$ 1,290.12**	**$ 1,298.92**	**$ 1,299.88**	**$ 1,297.50**	**$ 1,270.11**	**$ 1,280.22**
CAGR (2019 BASE)			4.8%				4.2%						3.1%
CAGR (MAY 2020 BASE)			5.4%				4.7%						3.5%

[1] Publicly available, annualized tariff rates consistent with the rebutt

[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LI

[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approv

[4] Includes the cost of REC purchases, deficiency payments, and REC p

[5] Includes specific Company-owned projects and PPAs proposed in 20

[6] No assumptions modeled for exemptions to Riders OSW.

[7] While nuclear small modular reactors do not generate RECs, the ou

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - LEAST COST VCEA COMPLIANT WITHOUT EPA,
COMPANY METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 127,019.69	$ 127,019.69	$ 122,333.63	$ 123,780.20	$ 151,307.33	$ 143,305.96	$ 148,489.00
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (1,597.09)	$ (1,464.00)	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 37,760.00	$ 37,760.00	$ 42,270.00	$ 45,260.00	$ 35,280.00	$ 47,770.00	$ 60,900.00	$ 65,460.00	$ 78,210.00	$ 74,570.00	$ 82,170.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 178,080.00	$ 209,652.00	$ 197,142.00	$ 192,978.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,226.00	$ 17,436.00	$ 18,288.00	$ 17,802.00	$ 16,992.00
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 330.00	$ 570.00	$ 1,050.00	$ 1,530.00	$ 1,602.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ 1,562.82	$ 1,541.03	$ 1,515.31
Generation Infrastructure											
GENERATION RIDERS [2]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 4,054.82	$ 8,682.98	$ 19,100.00	$ 14,540.00	$ 19,650.00	$ 19,700.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 4,000.47	$ 2,030.00	$ 3,110.00	$ 8,370.00	$ 10,890.00	$ 12,480.00	$ 14,950.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,670.00	$ 3,570.00	$ 4,880.00
Distribution Infrastructure [3]											
DISTRIBUTION RIDERS	$ -	$ -	$ -	$ 20.00	$ 1,290.00	$ 510.00	$ 2,900.00	$ 1,260.00	$ 1,790.00	$ 1,910.00	$ 2,030.00
A5 Environmental											
RIDER E	$ 5,560.00	$ 5,560.00	$ 4,300.00	$ 3,140.00	$ 4,860.00	$ 4,440.00	$ 3,260.00	$ 1,630.00	$ 1,630.00	$ 2,050.00	$ 1,850.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,098.00	$ 7,098.00	$ 10,938.00	$ 14,274.00	$ 13,704.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 26,550.00	$ -	$ -	$ -	$ -	$ -
Additional Resources											
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,980.00	$ 11,640.00
RPS Program-Related Resources											
RIDER RPS [4]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 46,056.00	$ 33,828.00	$ 39,546.00	$ 49,974.00
RIDER CE [5]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 14,970.00	$ 23,284.00	$ 42,628.00	$ 54,048.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (7,830.00)	$ (10,230.00)	$ (18,168.00)	$ (22,080.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,464.00)	$ (4,092.00)	$ (8,082.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (800.00)	$ (1,220.00)	$ (2,720.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,960.00**	**$ 7,790.00**	**$ 19,148.00**	**$ 21,166.00**
RIDER OSW [6]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 33,590.00	$ 35,100.00	$ 32,680.00	$ 31,310.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,284.00)	$ (33,468.00)	$ (30,600.00)	$ (29,178.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,206.00)	$ (14,622.00)	$ (17,226.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,620.00)	$ (3,830.00)	$ (4,650.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 20,306.00**	**$ (5,194.00)**	**$ (16,372.00)**	**$ (19,744.00)**
NUCLEAR SMALL MODULAR REACTORS [7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 750.00	$ 710.00	$ 270.00	$ 160.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 72,072.00**	**$ 37,134.00**	**$ 42,592.00**	**$ 51,556.00**
TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 454,747.07**	**$ 421,468.51**	**$ 405,964.61**	**$ 494,856.20**	**$ 538,662.15**	**$ 536,396.99**	**$ 564,056.31**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[5] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

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Rate Outlook 2019 to 2045
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LARGE GENERAL BILL PROJECTION - LEAST COST VCEA COMPLIANT WITHOUT EPA, COMPANY METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039
DISTRIBUTION & GENERATION (BASE) [1]	$ 150,045.69	$ 149,586.32	$ 151,951.16	$ 150,650.50	$ 147,574.63	$ 144,153.84	$ 145,428.43	$ 144,958.72	$ 143,025.01	$ 140,857.63	$ 145,266.89
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 89,200.00	$ 95,160.00	$ 99,110.00	$ 102,140.00	$ 104,820.00	$ 107,260.00	$ 108,010.00	$ 107,790.00	$ 107,670.00	$ 107,690.00	$ 107,670.00
FUEL - RIDER A	$ 188,526.00	$ 194,892.00	$ 191,760.00	$ 193,284.00	$ 197,268.00	$ 197,844.00	$ 209,322.00	$ 222,228.00	$ 227,688.00	$ 234,270.00	$ 251,238.00
FUEL SECURITIZATION	$ 16,578.00	$ 14,754.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,656.00	$ 1,602.00	$ 1,548.00	$ 1,416.00	$ 1,368.00	$ 1,356.00	$ 1,326.00	$ 1,284.00	$ 1,242.00	$ 1,194.00	$ 1,158.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1,485.05	$ 1,448.96	$ 1,414.60	$ 1,379.13	$ 1,350.56	$ 1,322.84	$ 1,296.03	$ 1,268.22	$ 1,247.84	$ 1,230.34	$ 1,142.70
Generation Infrastructure											
GENERATION RIDERS [2]	$ 20,130.00	$ 19,630.00	$ 18,290.00	$ 17,530.00	$ 17,350.00	$ 16,160.00	$ 15,580.00	$ 14,930.00	$ 14,850.00	$ 14,730.00	$ 13,540.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 17,620.00	$ 20,620.00	$ 22,110.00	$ 22,100.00	$ 21,410.00	$ 20,480.00	$ 19,540.00	$ 18,310.00	$ 17,140.00	$ 15,850.00	$ 14,700.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 6,760.00	$ 8,170.00	$ 7,740.00	$ 7,290.00	$ 6,830.00	$ 6,040.00	$ 5,710.00	$ 5,400.00	$ 5,110.00	$ 4,820.00	$ 4,560.00
Distribution Infrastructure [3]											
DISTRIBUTION RIDERS	$ 2,090.00	$ 2,020.00	$ 1,860.00	$ 1,680.00	$ 1,560.00	$ 1,450.00	$ 1,340.00	$ 1,240.00	$ 1,140.00	$ 1,050.00	$ 980.00
A5 Environmental											
RIDER E	$ 2,200.00	$ 2,220.00	$ 2,080.00	$ 1,580.00	$ 1,420.00	$ 1,310.00	$ 1,210.00	$ 1,110.00	$ 1,020.00	$ 940.00	$ 860.00
RIDER CCR	$ 13,110.00	$ 12,486.00	$ 11,874.00	$ 11,292.00	$ 10,812.00	$ 16,806.00	$ 10,866.00	$ 10,440.00	$ 1,380.00	$ 480.00	$ 1,170.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources											
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 19,820.00	$ 28,940.00	$ 39,180.00	$ 50,020.00	$ 71,840.00	$ 78,980.00	$ 81,540.00	$ 79,030.00	$ 76,020.00	$ 72,380.00	$ 68,100.00
RPS Program-Related Resources											
RIDER RPS [4]	$ 52,212.00	$ 55,938.00	$ 60,780.00	$ 63,378.00	$ 62,772.00	$ 62,514.00	$ 64,698.00	$ 65,046.00	$ 71,070.00	$ 76,200.00	$ 79,380.00
RIDER CE [5]	$ 63,912.00	$ 85,962.00	$ 104,036.00	$ 117,060.00	$ 129,648.00	$ 141,840.00	$ 153,654.00	$ 163,992.00	$ 173,556.00	$ 179,108.00	$ 183,138.00
RIDER CE - FUEL BENEFIT	$ (22,260.00)	$ (31,446.00)	$ (38,994.00)	$ (44,616.00)	$ (52,506.00)	$ (58,170.00)	$ (63,330.00)	$ (69,450.00)	$ (77,226.00)	$ (86,490.00)	$ (96,828.00)
RIDER CE - REC PROXY VALUE	$ (12,594.00)	$ (13,422.00)	$ (19,290.00)	$ (23,352.00)	$ (25,416.00)	$ (25,656.00)	$ (25,248.00)	$ (24,084.00)	$ (23,754.00)	$ (22,854.00)	$ (21,696.00)
RIDER CE - CAPACITY OFFSET	$ (3,750.00)	$ (4,110.00)	$ (4,480.00)	$ (4,920.00)	$ (5,650.00)	$ (6,680.00)	$ (7,550.00)	$ (8,370.00)	$ (9,170.00)	$ (9,870.00)	$ (10,380.00)
TOTAL RIDER CE	**$ 25,308.00**	**$ 36,984.00**	**$ 41,272.00**	**$ 44,172.00**	**$ 46,076.00**	**$ 51,334.00**	**$ 57,526.00**	**$ 62,088.00**	**$ 63,406.00**	**$ 59,894.00**	**$ 54,234.00**
RIDER OSW [6]	$ 28,480.00	$ 25,610.00	$ 26,280.00	$ 27,170.00	$ 26,570.00	$ 30,150.00	$ 41,250.00	$ 61,300.00	$ 66,890.00	$ 72,710.00	$ 74,410.00
RIDER OSW - FUEL BENEFIT	$ (28,518.00)	$ (27,222.00)	$ (25,494.00)	$ (24,294.00)	$ (23,694.00)	$ (23,124.00)	$ (23,514.00)	$ (29,592.00)	$ (29,742.00)	$ (29,910.00)	$ (34,116.00)
RIDER OSW - REC PROXY VALUE	$ (17,502.00)	$ (16,794.00)	$ (15,528.00)	$ (14,106.00)	$ (12,408.00)	$ (10,710.00)	$ (9,132.00)	$ (8,238.00)	$ (9,276.00)	$ (8,058.00)	$ (6,936.00)
RIDER OSW - CAPACITY OFFSET	$ (4,330.00)	$ (3,700.00)	$ (3,580.00)	$ (3,590.00)	$ (3,690.00)	$ (3,560.00)	$ (3,350.00)	$ (4,000.00)	$ (4,450.00)	$ (4,450.00)	$ (4,470.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (21,870.00)**	**$ (22,106.00)**	**$ (18,322.00)**	**$ (14,820.00)**	**$ (13,222.00)**	**$ (7,244.00)**	**$ 5,254.00**	**$ 19,470.00**	**$ 23,422.00**	**$ 30,292.00**	**$ 28,888.00**
NUCLEAR SMALL MODULAR REACTORS [7]	$ 150.00	$ -	$ -	$ -	$ -	$ 450.00	$ 1,290.00	$ 3,090.00	$ 6,210.00	$ 10,460.00	$ 15,630.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 55,800.00**	**$ 70,816.00**	**$ 83,730.00**	**$ 92,730.00**	**$ 95,626.00**	**$ 107,054.00**	**$ 128,768.00**	**$ 149,694.00**	**$ 164,108.00**	**$ 176,846.00**	**$ 178,132.00**
TOTAL	**$ 585,020.74**	**$ 622,345.28**	**$ 632,647.76**	**$ 653,091.63**	**$ 679,229.19**	**$ 700,216.68**	**$ 729,936.46**	**$ 757,682.94**	**$ 761,640.85**	**$ 772,337.97**	**$ 788,517.59**
CAGR (2019 BASE)							4.7%				4.1%
CAGR (MAY 2020 BASE)							5.6%				4.8%

[1] Publicly available, annualized tariff rates consistent with th
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-
[3] Consolidated Distribution Riders GT, U, and RBB. Includes a
[4] Includes the cost of REC purchases, deficiency payments, a
[5] Includes specific Company-owned projects and PPAs propo
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate REC:

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - LEAST COST VCEA COMPLIANT WITHOUT EPA, COMPANY METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 145,733.15	$ 150,276.73	$ 151,797.98	$ 154,037.26	$ 155,534.92	$ 157,631.33
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 108,280.00	$ 108,460.00	$ 108,590.00	$ 108,650.00	$ 108,410.00	$ 108,160.00
FUEL - RIDER A	$ 264,156.00	$ 291,690.00	$ 315,648.00	$ 338,304.00	$ 365,352.00	$ 388,632.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,122.00	$ 1,098.00	$ 1,068.00	$ -	$ 1,020.00	$ 990.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1,133.41	$ 1,126.37	$ 1,120.49	$ 1,113.12	$ 1,107.45	$ 1,103.00
Generation Infrastructure						
GENERATION RIDERS [2]	$ 13,640.00	$ 13,090.00	$ 12,330.00	$ 11,530.00	$ 9,920.00	$ 9,990.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 13,630.00	$ 12,740.00	$ 11,880.00	$ 11,090.00	$ 10,360.00	$ 9,670.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 4,320.00	$ 4,120.00	$ 3,930.00	$ 3,740.00	$ 3,580.00	$ 3,450.00
Distribution Infrastructure [3]						
DISTRIBUTION RIDERS	$ 910.00	$ 810.00	$ 750.00	$ 660.00	$ 590.00	$ 550.00
A5 Environmental						
RIDER E	$ 800.00	$ 730.00	$ 670.00	$ 1,010.00	$ 270.00	$ 250.00
RIDER CCR	$ 498.00	$ 48.00	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources						
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 64,200.00	$ 61,000.00	$ 57,800.00	$ 54,810.00	$ 51,990.00	$ 49,200.00
RPS Program-Related Resources						
RIDER RPS [4]	$ 65,520.00	$ 74,718.00	$ 83,994.00	$ 87,708.00	$ 92,076.00	$ 99,570.00
RIDER CE [5]	$ 186,764.00	$ 189,364.00	$ 188,986.00	$ 92,472.00	$ 192,994.00	$ 194,918.00
RIDER CE - FUEL BENEFIT	$ (103,938.00)	$ (122,034.00)	$ (144,546.00)	$ (163,320.00)	$ (189,942.00)	$ (206,622.00)
RIDER CE - REC PROXY VALUE	$ (20,136.00)	$ (18,102.00)	$ (17,568.00)	$ (16,920.00)	$ (16,104.00)	$ (15,072.00)
RIDER CE - CAPACITY OFFSET	$ (10,510.00)	$ (10,110.00)	$ (9,670.00)	$ -	$ (8,380.00)	$ (7,720.00)
TOTAL RIDER CE	**$ 52,180.00**	**$ 39,118.00**	**$ 17,202.00**	**$ (87,768.00)**	**$ (21,432.00)**	**$ (34,496.00)**
RIDER OSW [6]	$ 85,290.00	$ 79,580.00	$ 75,010.00	$ -	$ 67,600.00	$ 65,310.00
RIDER OSW - FUEL BENEFIT	$ (55,644.00)	$ (60,264.00)	$ (65,274.00)	$ (71,184.00)	$ (77,532.00)	$ (82,338.00)
RIDER OSW - REC PROXY VALUE	$ (6,378.00)	$ (9,240.00)	$ (8,448.00)	$ (7,692.00)	$ (6,972.00)	$ (6,252.00)
RIDER OSW - CAPACITY OFFSET	$ (6,450.00)	$ (7,800.00)	$ (7,740.00)	$ -	$ (7,570.00)	$ (7,480.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 16,818.00**	**$ 2,276.00**	**$ (6,452.00)**	**$ (78,876.00)**	**$ (24,474.00)**	**$ (30,760.00)**
NUCLEAR SMALL MODULAR REACTORS [7]	$ 20,910.00	$ 26,190.00	$ 32,460.00	$ 34,760.00	$ 35,310.00	$ 32,810.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 155,428.00**	**$ 142,302.00**	**$ 127,204.00**	**$ (44,176.00)**	**$ 81,480.00**	**$ 67,124.00**
TOTAL	**$ 773,850.56**	**$ 787,491.10**	**$ 792,788.47**	**$ 640,768.38**	**$ 789,614.37**	**$ 796,750.33**
CAGR (2019 BASE)						3.2%
CAGR (MAY 2020 BASE)						3.7%

[1] Publicly available, annualized tariff rates consistent with th
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-
[3] Consolidated Distribution Riders GT, U, and RBB. Includes a
[4] Includes the cost of REC purchases, deficiency payments, a
[5] Includes specific Company-owned projects and PPAs propo
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate REC

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - COMPANY PREFERRED PLAN, DIRECTED METHODOLOGY

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	61.82	61.82	61.82	61.82	60.93	60.93	60.71	60.71	73.57	76.09	78.35	79.61	80.25	81.90	82.34	82.10	81.21	82.47
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	-	-	-	-	(0.47)	(0.43)	-	-	-	-	-	-	-	-	-	-	-	-
TRANSMISSION - RIDER T	19.72	19.72	20.29	16.60	12.91	15.58	19.40	21.49	23.42	26.45	29.74	33.02	36.30	39.17	41.82	44.52	47.14	49.16
FUEL - RIDER A	23.25	17.36	17.02	20.45	35.38	28.59	20.74	29.68	36.12	35.15	35.76	38.18	42.63	46.87	51.63	55.67	58.49	64.68
FUEL SECURITIZATION	-	-	-	-	-	-	3.37	2.91	3.05	2.97	2.83	2.76	2.46	-	-	-	-	-
DSM	1.13	1.13	1.47	1.31	1.60	1.84	1.55	1.57	2.04	2.17	2.25	2.23	2.24	2.24	2.21	2.20	2.22	2.23
RIDER PIPP - UNIVERSAL SERVICE FEE	-	-	-	0.03	0.03	0.73	-	-	0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.31	0.32	0.33
Generation Infrastructure																		
GENERATION RIDERS [2]	12.91	12.76	12.87	13.39	14.51	6.67	6.58	7.57	5.10	6.25	6.26	6.56	6.58	6.35	6.32	6.55	6.36	6.38
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	-	-	-	-	2.07	0.93	1.29	3.48	3.82	3.96	4.75	5.72	6.87	7.60	7.89	7.93	7.89	7.80
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	-	-	-	-	-	-	-	-	0.59	1.14	1.55	2.20	2.72	2.66	2.60	2.53	2.32	2.28
Distribution Infrastructure [3]																		
DISTRIBUTION RIDERS	1.84	1.40	1.40	2.16	3.84	2.53	7.81	6.77	8.93	9.82	10.72	11.35	12.07	11.24	10.91	10.61	10.31	10.01
A5 Environmental																		
RIDER E [4]	1.99	1.99	1.67	1.25	1.95	2.03	1.35	0.64	0.57	0.72	1.13	1.29	1.66	1.62	1.46	1.39	1.34	1.28
RIDER CCR	-	-	-	2.95	2.96	2.38	1.18	1.18	1.77	2.39	2.39	2.39	2.39	2.39	2.39	2.39	3.89	2.63
RIDER RGGI	-	-	-	2.39	-	4.64	-	-	-	-	-	-	-	-	-	-	-	-
Additional Resources																		
INCREMENTAL GENERIC DSM	-	-	-	-	-	-	-	-	4.07	4.91	6.22	2.36	2.34	2.36	2.36	2.31	2.32	2.83
GENERIC GAS	-	-	-	-	-	-	-	-	-	1.26	3.70	6.45	9.65	13.48	17.86	26.62	30.42	32.55
RPS Program-Related Resources																		
RIDER RPS [5]	-	-	-	0.18	1.81	1.32	4.69	7.68	5.22	6.20	7.70	7.89	8.35	8.65	8.44	7.77	6.80	5.48
RIDER CE [6]	-	-	-	0.19	1.67	2.59	4.10	6.17	10.61	13.12	15.78	18.99	25.23	30.67	34.88	39.20	43.70	48.21
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.38)	(1.15)	(1.22)	(1.55)	(2.33)	(3.19)	(3.87)	(3.99)	(5.76)	(8.32)	(11.01)	(13.57)	(15.71)	(17.85)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(1.02)	(0.72)	(1.40)	(2.13)	(2.21)	(3.12)	(3.59)	(3.64)	(3.43)	(3.00)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.03)	(0.03)	-	(0.96)	(0.38)	(0.39)	(0.88)	(1.21)	(1.33)	(1.41)	(1.51)	(1.78)	(2.20)	(2.65)
TOTAL RIDER CE	**-**	**-**	**-**	**0.19**	**1.26**	**1.41**	**2.89**	**3.67**	**6.87**	**8.82**	**9.64**	**11.66**	**15.93**	**17.82**	**18.77**	**20.21**	**22.37**	**24.71**
RIDER OSW [7]	-	-	-	-	1.45	4.74	8.63	13.57	12.40	11.49	11.13	10.84	10.03	11.03	12.75	15.74	20.18	23.85
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	(2.34)	(5.29)	(5.17)	(5.09)	(5.17)	(5.60)	(6.15)	(6.34)	(6.80)	(8.94)	(9.36)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	(0.66)	(2.45)	(2.89)	(2.93)	(2.79)	(2.52)	(2.19)	(1.83)	(1.51)	(1.48)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	(0.93)	(1.35)	(1.65)	(1.57)	(1.35)	(1.27)	(1.29)	(1.41)	(1.71)	(1.93)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**1.45**	**4.74**	**8.63**	**11.23**	**5.53**	**2.52**	**1.49**	**1.17**	**0.29**	**1.10**	**2.93**	**5.70**	**8.02**	**11.09**
NUCLEAR SMALL MODULAR REACTORS [8]	-	-	-	-	-	-	-	0.30	0.25	0.09	0.05	0.05	-	-	0.19	0.55	1.36	2.87
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**0.37**	**4.52**	**7.47**	**16.21**	**22.87**	**17.87**	**17.64**	**18.88**	**20.77**	**24.57**	**27.57**	**30.32**	**34.23**	**38.54**	**44.14**
TOTAL	**122.66**	**116.18**	**116.54**	**122.72**	**140.22**	**133.88**	**140.17**	**158.86**	**181.16**	**191.18**	**204.79**	**215.18**	**233.03**	**245.73**	**260.42**	**279.37**	**292.77**	**308.77**
CAGR (2019 BASE)																		5.9%
CAGR (MAY 2020 BASE)																		6.4%

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - COMPANY PREFERRED PLAN, DIRECTED METHODOLOGY

RESIDENTIAL Schedule 1 (1,000 kWh)	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 83.54	$ 83.51	$ 83.30	$ 84.16	$ 86.02	$ 87.88	$ 89.75	$ 91.30	$ 93.23	$ 94.81
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 50.82	$ 52.64	$ 54.41	$ 56.13	$ 57.80	$ 59.41	$ 60.98	$ 62.49	$ 63.95	$ 40.13
FUEL - RIDER A	$ 72.13	$ 77.62	$ 82.54	$ 88.94	$ 94.67	$ 100.80	$ 110.13	$ 117.63	$ 126.99	$ 138.79
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 0.33	$ 0.34	$ 0.35	$ 0.34	$ 0.34	$ 0.35	$ 0.36	$ 0.37	$ 0.38	$ 0.39
Generation Infrastructure										
GENERATION RIDERS [2]	$ 6.36	$ 6.55	$ 6.71	$ 6.36	$ 6.60	$ 6.48	$ 6.29	$ 6.02	$ 5.29	$ 5.42
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 7.58	$ 7.36	$ 7.07	$ 6.78	$ 6.50	$ 6.22	$ 5.96	$ 5.70	$ 5.46	$ 5.23
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 2.24	$ 2.19	$ 2.15	$ 2.10	$ 2.06	$ 2.01	$ 1.97	$ 1.92	$ 1.89	$ 1.87
Distribution Infrastructure [3]										
DISTRIBUTION RIDERS	$ 9.70	$ 9.41	$ 9.11	$ 8.81	$ 8.50	$ 8.09	$ 7.75	$ 7.32	$ 7.01	$ 6.70
A5 Environmental										
RIDER E [4]	$ 1.23	$ 1.18	$ 1.13	$ 1.08	$ 1.03	$ 0.98	$ 0.93	$ 1.00	$ 0.54	$ 0.51
RIDER CCR	$ 2.65	$ 0.37	$ 0.13	$ 0.33	$ 0.15	$ 0.01	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
INCREMENTAL GENERIC DSM	$ 8.98	$ 11.52	$ 12.73	$ 5.15	$ 3.90	$ 3.75	$ 3.96	$ 3.62	$ 3.45	$ 5.87
GENERIC GAS	$ 32.71	$ 32.64	$ 32.27	$ 31.41	$ 30.59	$ 29.78	$ 28.98	$ 28.18	$ 27.40	$ 26.61
RPS Program-Related Resources										
RIDER RPS [5]	$ 6.98	$ 8.99	$ 10.58	$ 8.55	$ 10.55	$ 12.25	$ 14.04	$ 16.00	$ 18.27	$ 21.50
RIDER CE [6]	$ 52.52	$ 56.73	$ 59.65	$ 61.83	$ 63.45	$ 64.73	$ 64.99	$ 66.41	$ 67.53	$ 69.06
RIDER CE - FUEL BENEFIT	$ (20.87)	$ (24.32)	$ (26.13)	$ (28.90)	$ (31.14)	$ (34.81)	$ (41.69)	$ (46.42)	$ (52.52)	$ (60.61)
RIDER CE - REC PROXY VALUE	$ (2.34)	$ (2.47)	$ (2.57)	$ (2.65)	$ (2.70)	$ (2.71)	$ (2.86)	$ (3.02)	$ (3.15)	$ (3.28)
RIDER CE - CAPACITY OFFSET	$ (3.08)	$ (3.44)	$ (3.79)	$ (4.07)	$ (4.22)	$ (4.14)	$ (4.06)	$ (3.79)	$ (3.67)	$ (3.46)
TOTAL RIDER CE	**$ 26.24**	**$ 26.50**	**$ 27.17**	**$ 26.21**	**$ 25.40**	**$ 23.07**	**$ 16.37**	**$ 13.19**	**$ 8.18**	**$ 1.71**
RIDER OSW [7]	$ 31.37	$ 35.31	$ 37.29	$ 44.17	$ 42.27	$ 40.91	$ 39.72	$ 38.68	$ 37.98	$ 37.85
RIDER OSW - FUEL BENEFIT	$ (9.68)	$ (10.07)	$ (11.54)	$ (19.23)	$ (20.18)	$ (21.60)	$ (23.14)	$ (24.88)	$ (26.73)	$ (28.52)
RIDER OSW - REC PROXY VALUE	$ (1.20)	$ (1.15)	$ (1.10)	$ (1.13)	$ (1.77)	$ (1.70)	$ (1.70)	$ (1.70)	$ (1.70)	$ (1.70)
RIDER OSW - CAPACITY OFFSET	$ (2.01)	$ (2.10)	$ (2.18)	$ (3.27)	$ (4.08)	$ (4.17)	$ (4.25)	$ (4.33)	$ (4.38)	$ (4.44)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 18.48**	**$ 22.00**	**$ 22.48**	**$ 20.54**	**$ 16.23**	**$ 13.43**	**$ 10.63**	**$ 7.77**	**$ 5.18**	**$ 3.19**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 5.13	$ 8.15	$ 11.68	$ 15.71	$ 20.84	$ 24.07	$ 26.28	$ 27.49	$ 27.86	$ 26.65
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 56.83**	**$ 65.64**	**$ 71.90**	**$ 71.01**	**$ 73.02**	**$ 72.82**	**$ 67.31**	**$ 64.45**	**$ 59.50**	**$ 53.05**
TOTAL	**$ 337.32**	**$ 353.18**	**$ 366.02**	**$ 364.84**	**$ 373.39**	**$ 380.81**	**$ 386.57**	**$ 392.21**	**$ 397.30**	**$ 381.61**
CAGR (2019 BASE)				5.6%						4.5%
CAGR (MAY 2020 BASE)				6.0%						4.7%

[1] Publicly available, annualized tariff rates consistent with the rebu
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all app
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC
[6] Includes specific Company-owned projects and PPAs proposed in
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - COMPANY PREFERRED PLAN, DIRECTED METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 312.72	$ 316.26	$ 325.85	$ 330.78	$ 332.75	$ 339.44
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 95.33	$ 103.90	$ 117.31	$ 131.90	$ 146.48	$ 161.02	$ 173.74
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 178.08	$ 216.70	$ 210.91	$ 214.58	$ 229.09	$ 255.79	$ 281.21
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 17.44	$ 18.29	$ 17.80	$ 16.99	$ 16.58	$ 14.75	$ -
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 6.77	$ 6.36	$ 6.96	$ 10.26	$ 10.91	$ 11.29	$ 11.21	$ 11.25	$ 11.27
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ 1.56	$ 1.60	$ 1.64	$ 1.68	$ 1.72	$ 1.77
Generation Infrastructure														
GENERATION RIDERS [2]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 35.96	$ 23.91	$ 29.28	$ 29.33	$ 30.74	$ 30.86	$ 29.77
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 15.37	$ 17.90	$ 18.58	$ 22.27	$ 26.84	$ 32.22	$ 35.65
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.75	$ 5.32	$ 7.27	$ 10.30	$ 12.77	$ 12.49
Distribution Infrastructure [3]														
DISTRIBUTION RIDERS	$ 8.75	$ 5.90	$ 5.90	$ 9.30	$ 15.41	$ 10.63	$ 26.83	$ 26.10	$ 34.37	$ 37.80	$ 41.24	$ 43.66	$ 46.45	$ 43.23
A5 Environmental														
RIDER E [4]	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.07	$ 2.68	$ 3.05	$ 2.75	$ 3.34	$ 3.49	$ 3.35
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.10	$ 7.10	$ 10.59	$ 14.36	$ 14.36	$ 14.36	$ 14.36	$ 14.33
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 26.55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources														
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.45	$ 24.65	$ 31.24	$ 11.87	$ 11.78	$ 11.88
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.92	$ 17.34	$ 30.21	$ 45.22	$ 63.18
RPS Program-Related Resources														
RIDER RPS [5]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 46.06	$ 31.32	$ 37.22	$ 46.18	$ 47.36	$ 50.09	$ 51.89
RIDER CE [6]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.46	$ 17.97	$ 27.64	$ 54.16	$ 67.27	$ 81.65	$ 97.99	$ 130.84	$ 159.58
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.14)	$ (13.98)	$ (19.09)	$ (23.21)	$ (23.88)	$ (34.51)	$ (49.87)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.11)	$ (4.28)	$ (8.39)	$ (12.77)	$ (13.27)	$ (18.68)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (1.94)	$ (1.98)	$ (4.44)	$ (6.15)	$ (6.73)	$ (7.17)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.75**	**$ 10.68**	**$ 15.20**	**$ 32.14**	**$ 41.92**	**$ 45.61**	**$ 55.19**	**$ 76.33**	**$ 83.86**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 60.00	$ 62.30	$ 57.73	$ 55.92	$ 54.46	$ 50.40	$ 55.43
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12.19)	$ (31.41)	$ (30.72)	$ (30.24)	$ (30.74)	$ (33.26)	$ (36.52)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3.94)	$ (14.58)	$ (17.19)	$ (17.38)	$ (16.58)	$ (14.99)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4.65)	$ (6.76)	$ (8.31)	$ (7.89)	$ (6.79)	$ (6.36)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 47.81**	**$ 22.30**	**$ 5.66**	**$ 0.18**	**$ (1.55)**	**$ (6.23)**	**$ (2.44)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.40	$ 1.16	$ 0.41	$ 0.23	$ 0.23	$ -	$ -
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.38**	**$ 74.18**	**$ 110.48**	**$ 86.92**	**$ 85.21**	**$ 92.21**	**$ 101.24**	**$ 120.18**	**$ 133.31**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 642.44**	**$ 646.43**	**$ 760.47**	**$ 862.98**	**$ 898.96**	**$ 960.25**	**$ 1,008.37**	**$ 1,094.60**	**$ 1,154.61**
CAGR (2019 BASE)														
CAGR (MAY 2020 BASE)														

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - COMPANY PREFERRED PLAN, DIRECTED METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044
DISTRIBUTION & GENERATION (BASE) [1]	$ 340.43	$ 338.18	$ 332.90	$ 337.68	$ 341.56	$ 340.23	$ 338.06	$ 340.86	$ 348.30	$ 355.75	$ 363.20	$ 369.14	$ 376.83
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 185.50	$ 197.45	$ 209.11	$ 218.04	$ 225.41	$ 233.50	$ 241.34	$ 248.97	$ 256.37	$ 263.54	$ 270.47	$ 277.19	$ 283.67
FUEL - RIDER A	$ 309.79	$ 334.01	$ 350.93	$ 388.06	$ 432.77	$ 465.73	$ 495.25	$ 533.66	$ 568.04	$ 604.80	$ 660.77	$ 705.75	$ 761.93
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 11.09	$ 11.04	$ 11.16	$ 11.19	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1.81	$ 1.86	$ 1.90	$ 1.95	$ 2.00	$ 2.05	$ 2.10	$ 2.01	$ 2.06	$ 2.12	$ 2.17	$ 2.22	$ 2.28
Generation Infrastructure													
GENERATION RIDERS [2]	$ 29.63	$ 30.70	$ 29.84	$ 29.94	$ 29.83	$ 30.70	$ 31.45	$ 29.80	$ 30.94	$ 30.40	$ 29.48	$ 28.24	$ 24.82
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 37.00	$ 37.19	$ 36.98	$ 36.56	$ 35.53	$ 34.49	$ 33.14	$ 31.79	$ 30.46	$ 29.16	$ 27.92	$ 26.73	$ 25.59
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 12.20	$ 11.87	$ 10.90	$ 10.69	$ 10.49	$ 10.28	$ 10.07	$ 9.86	$ 9.65	$ 9.44	$ 9.23	$ 9.01	$ 8.84
Distribution Infrastructure [3]													
DISTRIBUTION RIDERS	$ 41.97	$ 40.84	$ 39.67	$ 38.51	$ 37.33	$ 36.19	$ 35.05	$ 33.91	$ 32.71	$ 31.13	$ 29.83	$ 28.15	$ 26.98
A5 Environmental													
RIDER E [4]	$ 2.63	$ 2.47	$ 2.36	$ 2.27	$ 2.17	$ 2.05	$ 1.96	$ 1.87	$ 1.78	$ 1.67	$ 1.58	$ 2.42	$ 0.69
RIDER CCR	$ 14.33	$ 14.36	$ 23.36	$ 15.80	$ 15.91	$ 2.19	$ 0.79	$ 1.99	$ 0.87	$ 0.08	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources													
INCREMENTAL GENERIC DSM	$ 11.86	$ 11.59	$ 11.65	$ 14.21	$ 45.11	$ 57.91	$ 63.97	$ 25.88	$ 19.58	$ 18.83	$ 19.92	$ 18.20	$ 17.32
GENERIC GAS	$ 83.74	$ 124.81	$ 142.60	$ 152.59	$ 153.35	$ 153.01	$ 151.30	$ 147.28	$ 143.41	$ 139.61	$ 135.85	$ 132.13	$ 128.44
RPS Program-Related Resources													
RIDER RPS [5]	$ 50.63	$ 46.63	$ 40.79	$ 32.86	$ 41.88	$ 53.94	$ 63.46	$ 51.29	$ 63.32	$ 73.51	$ 84.22	$ 95.97	$ 109.62
RIDER CE [6]	$ 182.03	$ 205.06	$ 228.97	$ 252.93	$ 275.80	$ 298.31	$ 314.39	$ 326.74	$ 337.09	$ 345.70	$ 349.22	$ 358.65	$ 366.59
RIDER CE - FUEL BENEFIT	$ (65.99)	$ (81.32)	$ (94.15)	$ (106.93)	$ (125.02)	$ (145.72)	$ (156.57)	$ (173.17)	$ (186.58)	$ (208.57)	$ (249.84)	$ (278.14)	$ (314.71)
RIDER CE - REC PROXY VALUE	$ (21.52)	$ (21.83)	$ (20.53)	$ (17.96)	$ (14.01)	$ (14.78)	$ (15.38)	$ (15.84)	$ (16.18)	$ (16.25)	$ (17.14)	$ (18.07)	$ (18.89)
RIDER CE - CAPACITY OFFSET	$ (7.63)	$ (9.03)	$ (11.12)	$ (13.42)	$ (15.59)	$ (17.43)	$ (19.22)	$ (20.65)	$ (21.37)	$ (20.99)	$ (20.59)	$ (19.21)	$ (18.61)
TOTAL RIDER CE	**$ 86.89**	**$ 92.88**	**$ 103.17**	**$ 114.61**	**$ 121.18**	**$ 120.38**	**$ 123.22**	**$ 117.08**	**$ 112.97**	**$ 99.88**	**$ 61.66**	**$ 43.24**	**$ 14.38**
RIDER OSW [7]	$ 64.04	$ 79.08	$ 101.35	$ 119.83	$ 157.60	$ 177.41	$ 187.35	$ 221.89	$ 212.35	$ 205.51	$ 199.55	$ 194.33	$ 190.82
RIDER OSW - FUEL BENEFIT	$ (37.64)	$ (40.41)	$ (53.10)	$ (55.63)	$ (57.52)	$ (59.82)	$ (68.54)	$ (114.29)	$ (119.92)	$ (128.35)	$ (137.52)	$ (147.83)	$ (158.81)
RIDER OSW - REC PROXY VALUE	$ (13.03)	$ (10.87)	$ (8.98)	$ (8.78)	$ (7.12)	$ (6.82)	$ (6.51)	$ (6.69)	$ (10.54)	$ (10.11)	$ (10.10)	$ (10.10)	$ (10.11)
RIDER OSW - CAPACITY OFFSET	$ (6.49)	$ (7.08)	$ (8.60)	$ (9.67)	$ (10.10)	$ (10.55)	$ (10.94)	$ (16.43)	$ (20.52)	$ (20.95)	$ (21.35)	$ (21.74)	$ (21.98)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 6.88**	**$ 20.72**	**$ 30.67**	**$ 45.74**	**$ 82.86**	**$ 100.23**	**$ 101.36**	**$ 84.49**	**$ 61.37**	**$ 46.10**	**$ 30.58**	**$ 14.66**	**$ (0.07)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 0.87	$ 2.57	$ 6.39	$ 13.45	$ 24.07	$ 38.19	$ 54.74	$ 73.67	$ 97.72	$ 112.84	$ 123.20	$ 128.90	$ 130.63
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 145.27**	**$ 162.81**	**$ 181.03**	**$ 206.67**	**$ 269.98**	**$ 312.74**	**$ 342.77**	**$ 326.53**	**$ 335.39**	**$ 332.33**	**$ 299.65**	**$ 282.77**	**$ 254.56**
TOTAL	**$ 1,227.25**	**$ 1,319.19**	**$ 1,384.39**	**$ 1,464.18**	**$ 1,612.61**	**$ 1,692.25**	**$ 1,758.42**	**$ 1,745.59**	**$ 1,790.73**	**$ 1,830.04**	**$ 1,861.25**	**$ 1,893.12**	**$ 1,923.14**
CAGR (2019 BASE)				6.0%				5.7%					
CAGR (MAY 2020 BASE)				6.7%				6.2%					

[1] Publicly available, annualized tariff rates consistent with the rebut
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and U
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all appr
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC
[6] Includes specific Company-owned projects and PPAs proposed in 2
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the o

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)		2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$	382.86
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$	-
TRANSMISSION - RIDER T	$	193.88
FUEL - RIDER A	$	832.75
FUEL SECURITIZATION	$	-
DSM	$	11.18
RIDER PIPP - UNIVERSAL SERVICE FEE	$	2.34
Generation Infrastructure		
GENERATION RIDERS [2]	$	25.43
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$	24.52
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$	8.75
Distribution Infrastructure [3]		
DISTRIBUTION RIDERS	$	25.80
A5 Environmental		
RIDER E [4]	$	0.64
RIDER CCR	$	-
RIDER RGGI	$	-
Additional Resources		
INCREMENTAL GENERIC DSM	$	29.48
GENERIC GAS	$	124.76
RPS Program-Related Resources		
RIDER RPS [5]	$	128.98
RIDER CE [6]	$	376.58
RIDER CE - FUEL BENEFIT	$	(363.22)
RIDER CE - REC PROXY VALUE	$	(19.64)
RIDER CE - CAPACITY OFFSET	$	(17.53)
TOTAL RIDER CE	**$**	**(23.80)**
RIDER OSW [7]	$	190.17
RIDER OSW - FUEL BENEFIT	$	(169.47)
RIDER OSW - REC PROXY VALUE	$	(10.10)
RIDER OSW - CAPACITY OFFSET	$	(22.29)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$**	**(11.69)**
NUCLEAR SMALL MODULAR REACTORS [8]	$	124.96
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$**	**218.44**
TOTAL	**$**	**1,880.83**
CAGR (2019 BASE)		4.7%
CAGR (MAY 2020 BASE)		5.0%

[1] Publicly available, annualized tariff rates consistent with the rebut
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and I
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all appr
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC
[6] Includes specific Company-owned projects and PPAs proposed in 2
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the o

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - COMPANY PREFERRED PLAN, DIRECTED METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 127,019.69	$ 127,019.69	$ 122,333.63	$ 123,780.20	$ 151,307.33	$ 141,865.96	$ 146,629.00
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (1,597.09)	$ (1,464.00)	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 37,760.00	$ 37,760.00	$ 42,270.00	$ 45,260.00	$ 35,280.00	$ 47,770.00	$ 60,900.00	$ 65,460.00	$ 71,340.00	$ 80,550.00	$ 90,570.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 178,080.00	$ 216,702.00	$ 210,912.00	$ 214,578.00
FUEL SECURITIZATION	$ 139,524.00	$ 104,142.00	$ -	$ -	$ -	$ -	$ 20,226.00	$ 17,436.00	$ 18,288.00	$ 17,802.00	$ 16,992.00
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 330.00	$ 570.00	$ 1,050.00	$ 1,254.00	$ 1,326.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ 1,562.82	$ 1,600.96	$ 1,640.24
Generation Infrastructure											
GENERATION RIDERS [2]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 19,100.00	$ 14,540.00	$ 17,820.00	$ 17,850.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 8,370.00	$ 10,890.00	$ 11,300.00	$ 13,550.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,670.00	$ 3,240.00	$ 4,420.00
Distribution Infrastructure [3]											
DISTRIBUTION RIDERS	$ -	$ -	$ -	$ 20.00	$ 1,290.00	$ 510.00	$ 2,900.00	$ 1,260.00	$ 1,750.00	$ 2,040.00	$ 2,280.00
A5 Environmental											
RIDER E [4]	$ 5,560.00	$ 5,560.00	$ 4,300.00	$ 3,140.00	$ 4,860.00	$ 4,440.00	$ 3,260.00	$ 1,630.00	$ 1,630.00	$ 1,850.00	$ 1,670.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,098.00	$ 7,098.00	$ 10,590.00	$ 14,358.00	$ 14,358.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 26,550.00	$ -	$ -	$ -	$ -	$ -
Additional Resources											
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,600.00	$ 10,550.00
RPS Program-Related Resources											
RIDER RPS [5]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 46,056.00	$ 31,320.00	$ 37,224.00	$ 46,182.00
RIDER CE [6]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 14,970.00	$ 23,284.00	$ 29,524.00	$ 37,296.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (7,830.00)	$ (10,230.00)	$ (13,968.00)	$ (16,980.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,464.00)	$ (3,126.00)	$ (6,156.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (800.00)	$ (820.00)	$ (1,840.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,960.00**	**$ 7,790.00**	**$ 11,610.00**	**$ 12,320.00**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 33,590.00	$ 35,100.00	$ 32,530.00	$ 31,510.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,284.00)	$ (33,504.00)	$ (32,766.00)	$ (32,256.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,206.00)	$ (15,552.00)	$ (18,342.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,620.00)	$ (3,810.00)	$ (4,680.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 20,306.00**	**$ (5,230.00)**	**$ (19,598.00)**	**$ (23,768.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 750.00	$ 710.00	$ 250.00	$ 140.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 72,072.00**	**$ 34,590.00**	**$ 29,486.00**	**$ 34,874.00**
TOTAL	**$ 490,384.69**	**$ 417,020.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 432,893.69**	**$ 412,671.63**	**$ 494,856.20**	**$ 535,910.15**	**$ 537,678.92**	**$ 571,287.24**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - COMPANY PREFERRED PLAN, DIRECTED METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038
DISTRIBUTION & GENERATION (BASE) [1]	$ 148,545.69	$ 148,626.32	$ 151,561.16	$ 151,000.50	$ 148,454.63	$ 144,033.84	$ 145,718.43	$ 146,818.72	$ 144,735.01	$ 142,107.63
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 100,580.00	$ 110,560.00	$ 119,290.00	$ 127,370.00	$ 135,580.00	$ 143,590.00	$ 149,720.00	$ 154,780.00	$ 160,330.00	$ 165,720.00
FUEL - RIDER A	$ 229,086.00	$ 255,786.00	$ 281,208.00	$ 309,792.00	$ 334,014.00	$ 350,934.00	$ 388,062.00	$ 432,768.00	$ 465,726.00	$ 495,252.00
FUEL SECURITIZATION	$ 16,578.00	$ 14,754.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,392.00	$ 1,380.00	$ 1,368.00	$ 1,296.00	$ 1,296.00	$ 1,332.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1,680.70	$ 1,722.37	$ 1,765.29	$ 1,809.50	$ 1,855.04	$ 1,901.94	$ 1,950.25	$ 2,000.01	$ 2,051.27	$ 2,104.06
Generation Infrastructure										
GENERATION RIDERS [2]	$ 18,720.00	$ 18,770.00	$ 18,140.00	$ 18,040.00	$ 18,690.00	$ 18,140.00	$ 18,230.00	$ 18,140.00	$ 18,710.00	$ 19,140.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 16,330.00	$ 19,600.00	$ 21,700.00	$ 22,510.00	$ 22,630.00	$ 22,510.00	$ 22,250.00	$ 21,620.00	$ 20,990.00	$ 20,160.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 6,270.00	$ 7,770.00	$ 7,600.00	$ 7,430.00	$ 7,220.00	$ 6,630.00	$ 6,510.00	$ 6,380.00	$ 6,260.00	$ 6,130.00
Distribution Infrastructure [3]										
DISTRIBUTION RIDERS	$ 2,460.00	$ 2,530.00	$ 2,460.00	$ 2,380.00	$ 2,320.00	$ 2,240.00	$ 2,160.00	$ 2,090.00	$ 2,020.00	$ 1,950.00
A5 Environmental										
RIDER E [4]	$ 2,020.00	$ 2,120.00	$ 2,040.00	$ 1,610.00	$ 1,510.00	$ 1,430.00	$ 1,380.00	$ 1,320.00	$ 1,250.00	$ 1,200.00
RIDER CCR	$ 14,358.00	$ 14,358.00	$ 14,328.00	$ 14,328.00	$ 14,358.00	$ 23,358.00	$ 15,804.00	$ 15,906.00	$ 2,190.00	$ 786.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 18,380.00	$ 27,520.00	$ 38,450.00	$ 50,960.00	$ 75,950.00	$ 86,780.00	$ 92,860.00	$ 93,320.00	$ 93,120.00	$ 92,080.00
RPS Program-Related Resources										
RIDER RPS [5]	$ 47,364.00	$ 50,088.00	$ 51,894.00	$ 50,628.00	$ 46,632.00	$ 40,794.00	$ 32,862.00	$ 41,880.00	$ 53,940.00	$ 63,456.00
RIDER CE [6]	$ 44,274.00	$ 60,466.00	$ 74,738.00	$ 86,408.00	$ 98,244.00	$ 110,470.00	$ 122,660.00	$ 134,344.00	$ 146,078.00	$ 155,286.00
RIDER CE - FUEL BENEFIT	$ (17,484.00)	$ (25,248.00)	$ (36,486.00)	$ (48,294.00)	$ (59,496.00)	$ (68,886.00)	$ (78,258.00)	$ (91,476.00)	$ (106,626.00)	$ (114,558.00)
RIDER CE - REC PROXY VALUE	$ (9,348.00)	$ (9,708.00)	$ (13,668.00)	$ (15,738.00)	$ (15,972.00)	$ (15,024.00)	$ (13,140.00)	$ (10,254.00)	$ (10,812.00)	$ (11,262.00)
RIDER CE - CAPACITY OFFSET	$ (2,570.00)	$ (2,800.00)	$ (2,970.00)	$ (3,170.00)	$ (3,730.00)	$ (4,630.00)	$ (5,580.00)	$ (6,470.00)	$ (7,230.00)	$ (7,950.00)
TOTAL RIDER CE	**$ 14,872.00**	**$ 22,710.00**	**$ 21,614.00**	**$ 19,206.00**	**$ 19,046.00**	**$ 21,930.00**	**$ 25,682.00**	**$ 26,144.00**	**$ 21,410.00**	**$ 21,516.00**
RIDER OSW [7]	$ 30,690.00	$ 28,410.00	$ 31,240.00	$ 36,090.00	$ 44,560.00	$ 57,110.00	$ 67,510.00	$ 88,800.00	$ 99,960.00	$ 105,560.00
RIDER OSW - FUEL BENEFIT	$ (32,790.00)	$ (35,484.00)	$ (38,952.00)	$ (40,152.00)	$ (43,098.00)	$ (56,640.00)	$ (59,340.00)	$ (61,362.00)	$ (63,810.00)	$ (73,110.00)
RIDER OSW - REC PROXY VALUE	$ (18,540.00)	$ (17,694.00)	$ (15,996.00)	$ (13,896.00)	$ (11,586.00)	$ (9,570.00)	$ (9,372.00)	$ (7,596.00)	$ (7,266.00)	$ (6,948.00)
RIDER OSW - CAPACITY OFFSET	$ (4,450.00)	$ (3,820.00)	$ (3,580.00)	$ (3,660.00)	$ (3,990.00)	$ (4,840.00)	$ (5,450.00)	$ (5,700.00)	$ (5,940.00)	$ (6,170.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW	**$ (25,090.00)**	**$ (28,588.00)**	**$ (27,288.00)**	**$ (21,618.00)**	**$ (14,114.00)**	**$ (13,940.00)**	**$ (6,652.00)**	**$ 14,142.00**	**$ 22,944.00**	**$ 19,332.00**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 140.00	$ -	$ -	$ 530.00	$ 1,570.00	$ 3,890.00	$ 8,180.00	$ 14,640.00	$ 23,240.00	$ 33,310.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 37,286.00**	**$ 44,210.00**	**$ 46,220.00**	**$ 48,746.00**	**$ 53,134.00**	**$ 52,674.00**	**$ 60,072.00**	**$ 96,806.00**	**$ 121,534.00**	**$ 137,614.00**
TOTAL	**$ 613,686.39**	**$ 669,706.69**	**$ 706,130.45**	**$ 757,272.00**	**$ 817,011.67**	**$ 855,553.78**	**$ 906,060.68**	**$ 993,292.73**	**$ 1,040,260.28**	**$ 1,085,587.69**
CAGR (2019 BASE)							3.9%			
CAGR (MAY 2020 BASE)							5.1%			

[1] Publicly available, annualized tariff rates consistent with t
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US
[3] Consolidated Distribution Riders GT, U, and RBB. Includes
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, a
[6] Includes specific Company-owned projects and PPAs prop
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate REC

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - COMPANY PREFERRED PLAN, DIRECTED METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 142,476.89	$ 145,653.15	$ 148,796.73	$ 151,917.98	$ 154,087.26	$ 157,304.92	$ 159,471.33
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 170,950.00	$ 176,030.00	$ 180,950.00	$ 185,720.00	$ 190,330.00	$ 194,780.00	$ 108,160.00
FUEL - RIDER A	$ 533,664.00	$ 568,038.00	$ 604,800.00	$ 660,774.00	$ 705,750.00	$ 761,928.00	$ 832,746.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 2,014.19	$ 2,063.88	$ 2,115.06	$ 2,167.78	$ 2,222.08	$ 2,278.00	$ 2,335.61
Generation Infrastructure							
GENERATION RIDERS [2]	$ 18,150.00	$ 18,850.00	$ 18,500.00	$ 17,930.00	$ 17,180.00	$ 15,090.00	$ 15,470.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 19,350.00	$ 18,540.00	$ 17,750.00	$ 16,990.00	$ 16,270.00	$ 15,570.00	$ 14,920.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 6,000.00	$ 5,870.00	$ 5,740.00	$ 5,610.00	$ 5,480.00	$ 5,380.00	$ 5,330.00
Distribution Infrastructure [3]							
DISTRIBUTION RIDERS	$ 1,870.00	$ 1,790.00	$ 1,680.00	$ 1,580.00	$ 1,450.00	$ 1,360.00	$ 1,280.00
A5 Environmental							
RIDER E [4]	$ 1,120.00	$ 1,070.00	$ 1,010.00	$ 950.00	$ 1,470.00	$ 410.00	$ 380.00
RIDER CCR	$ 1,986.00	$ 870.00	$ 84.00	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources							
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 89,620.00	$ 87,270.00	$ 84,960.00	$ 82,670.00	$ 80,410.00	$ 78,170.00	$ 75,920.00
RPS Program-Related Resources							
RIDER RPS [5]	$ 51,288.00	$ 63,324.00	$ 73,512.00	$ 84,216.00	$ 95,970.00	$ 109,620.00	$ 128,976.00
RIDER CE [6]	$ 163,160.00	$ 171,904.00	$ 179,780.00	$ 185,774.00	$ 194,288.00	$ 202,212.00	$ 210,926.00
RIDER CE - FUEL BENEFIT	$ (126,702.00)	$ (136,530.00)	$ (152,616.00)	$ (182,808.00)	$ (203,520.00)	$ (230,280.00)	$ (265,758.00)
RIDER CE - REC PROXY VALUE	$ (11,604.00)	$ (11,850.00)	$ (11,898.00)	$ (12,540.00)	$ (13,218.00)	$ (13,824.00)	$ (14,376.00)
RIDER CE - CAPACITY OFFSET	$ (8,580.00)	$ (8,860.00)	$ (8,710.00)	$ (8,550.00)	$ (7,960.00)	$ (7,720.00)	$ (7,260.00)
TOTAL RIDER CE	**$ 16,274.00**	**$ 14,664.00**	**$ 6,556.00**	**$ (18,124.00)**	**$ (30,410.00)**	**$ (49,612.00)**	**$ (76,468.00)**
RIDER OSW [7]	$ 125,020.00	$ 119,640.00	$ 115,800.00	$ 112,440.00	$ 109,490.00	$ 107,520.00	$ 107,150.00
RIDER OSW - FUEL BENEFIT	$ (121,908.00)	$ (127,908.00)	$ (136,914.00)	$ (146,694.00)	$ (157,686.00)	$ (169,398.00)	$ (180,774.00)
RIDER OSW - REC PROXY VALUE	$ (7,134.00)	$ (11,238.00)	$ (10,782.00)	$ (10,776.00)	$ (10,770.00)	$ (10,782.00)	$ (10,776.00)
RIDER OSW - CAPACITY OFFSET	$ (9,250.00)	$ (11,570.00)	$ (11,810.00)	$ (12,030.00)	$ (12,260.00)	$ (12,380.00)	$ (12,560.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW	**$ (13,272.00)**	**$ (31,076.00)**	**$ (43,706.00)**	**$ (57,060.00)**	**$ (71,226.00)**	**$ (85,040.00)**	**$ (96,960.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 44,830.00	$ 59,470.00	$ 68,670.00	$ 74,980.00	$ 78,440.00	$ 79,490.00	$ 76,040.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 99,120.00**	**$ 106,382.00**	**$ 105,032.00**	**$ 84,012.00**	**$ 72,774.00**	**$ 54,458.00**	**$ 31,588.00**
TOTAL	**$ 1,087,665.08**	**$ 1,133,771.03**	**$ 1,172,761.79**	**$ 1,211,665.76**	**$ 1,248,767.34**	**$ 1,288,072.92**	**$ 1,248,944.94**
CAGR (2019 BASE)	4.1%						3.7%
CAGR (MAY 2020 BASE)	5.0%						4.4%

[1] Publicly available, annualized tariff rates consistent with t
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US
[3] Consolidated Distribution Riders GT, U, and RBB. Includes
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, a
[6] Includes specific Company-owned projects and PPAs prop
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RE(

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, DIRECTED METHODOLOGY

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 60.93	$ 60.93	$ 60.71	$ 60.71	$ 73.57	$ 76.09	$ 78.35	$ 79.61	$ 80.25	$ 81.56	$ 82.08	$ 81.88	$ 79.90	$ 81.39
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (0.47)	$ (0.43)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	$ 12.91	$ 15.58	$ 19.40	$ 20.86	$ 23.46	$ 26.43	$ 29.43	$ 32.25	$ 35.00	$ 37.69	$ 40.31	$ 42.87	$ 44.86	$ 46.51
FUEL - RIDER A	$ 23.25	$ 17.36	$ 17.02	$ 20.45	$ 35.38	$ 28.59	$ 20.74	$ 29.68	$ 36.11	$ 35.13	$ 35.74	$ 38.16	$ 42.65	$ 46.93	$ 51.62	$ 55.33	$ 57.20	$ 64.80
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.37	$ 2.91	$ 3.05	$ 2.97	$ 2.83	$ 2.76	$ 2.46	$ -	$ -	$ -	$ -	$ -
DSM	$ 1.13	$ 1.13	$ 1.47	$ 1.31	$ 1.60	$ 1.84	$ 1.55	$ 1.57	$ 2.04	$ 2.17	$ 2.25	$ 2.23	$ 2.24	$ 2.24	$ 2.21	$ 2.20	$ 2.22	$ 2.23
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 0.03	$ 0.03	$ 0.73	$ -	$ -	$ 0.26	$ 0.27	$ 0.27	$ 0.28	$ 0.29	$ 0.29	$ 0.30	$ 0.31	$ 0.32	$ 0.33
Generation Infrastructure																		
GENERATION RIDERS [2]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	$ 14.51	$ 6.67	$ 6.58	$ 7.57	$ 5.10	$ 6.25	$ 6.26	$ 6.56	$ 6.60	$ 6.36	$ 6.33	$ 6.55	$ 6.36	$ 6.38
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 2.07	$ 0.93	$ 1.29	$ 3.48	$ 3.82	$ 3.96	$ 4.75	$ 5.72	$ 6.87	$ 7.60	$ 7.89	$ 7.93	$ 7.89	$ 7.80
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.59	$ 1.14	$ 1.55	$ 2.20	$ 2.72	$ 2.66	$ 2.60	$ 2.53	$ 2.32	$ 2.28
Distribution Infrastructure [3]																		
DISTRIBUTION RIDERS	$ 1.84	$ 1.40	$ 1.40	$ 2.16	$ 3.84	$ 2.53	$ 7.81	$ 6.77	$ 8.93	$ 9.82	$ 10.72	$ 11.35	$ 12.07	$ 11.24	$ 10.91	$ 10.61	$ 10.31	$ 10.01
A5 Environmental																		
RIDER E [4]	$ 1.99	$ 1.99	$ 1.67	$ 1.25	$ 1.95	$ 2.03	$ 1.35	$ 0.64	$ 0.57	$ 0.72	$ 1.13	$ 1.29	$ 1.66	$ 1.62	$ 1.46	$ 1.39	$ 1.34	$ 1.28
RIDER CCR	$ -	$ -	$ -	$ 2.95	$ 2.96	$ 2.38	$ 1.18	$ 1.18	$ 1.77	$ 2.39	$ 2.39	$ 2.39	$ 2.39	$ 2.39	$ 2.39	$ 2.39	$ 3.89	$ 2.63
RIDER RGGI	$ -	$ -	$ -	$ 2.39	$ -	$ 4.64	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.07	$ 4.91	$ 6.22	$ 2.36	$ 2.34	$ 2.36	$ 2.36	$ 2.31	$ 2.32	$ 2.83
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.26	$ 3.69	$ 6.26	$ 8.72	$ 10.85	$ 12.19	$ 15.02	$ 15.12	$ 14.72
BRUNSWICK - 2044 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.15	$ 0.14	$ 0.17	$ 0.18	$ 0.18	$ 0.17	$ 0.18	$ 0.17	$ 0.16
GREENVILLE - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.14	$ 0.10	$ 0.47	$ 0.28	$ 0.10	$ 0.26	$ 0.23	$ 0.25	$ 0.25	$ 0.24
LNG - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.12	$ 0.15	$ 0.14	$ 0.14	$ 0.14	$ 0.13	$ 0.12	$ 0.11
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.01	$ 0.15	$ 0.14	$ 0.13	$ 0.12	$ 0.11	$ 0.10
CERC GAS CT - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.37	$ 0.62	$ 0.59	$ 0.55	$ 0.52	$ 0.48	$ 0.45
GAS CT GENERIC - 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.71	$ 1.18	$ 1.10	$ 1.02	$ 0.93
RPS Program-Related Resources																		
RIDER RPS [5]	$ -	$ -	$ -	$ 0.18	$ 1.81	$ 1.32	$ 4.69	$ 7.68	$ 5.22	$ 6.20	$ 7.70	$ 7.90	$ 8.37	$ 8.69	$ 8.73	$ 8.55	$ 7.50	$ 5.17
RIDER CE [6]	$ -	$ -	$ -	$ 0.19	$ 1.67	$ 2.59	$ 4.10	$ 6.17	$ 10.61	$ 13.25	$ 15.95	$ 19.27	$ 25.53	$ 30.73	$ 34.74	$ 40.59	$ 48.63	$ 57.11
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.38)	$ (1.15)	$ (1.22)	$ (1.55)	$ (2.33)	$ (3.18)	$ (3.86)	$ (3.96)	$ (5.20)	$ (7.20)	$ (9.15)	$ (11.08)	$ (14.76)	$ (18.26)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.02)	$ (0.72)	$ (1.40)	$ (2.13)	$ (2.20)	$ (2.81)	$ (3.10)	$ (3.03)	$ (2.79)	$ (2.82)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.03)	$ (0.03)	$ -	$ (0.96)	$ (0.38)	$ (0.39)	$ (0.88)	$ (1.21)	$ (1.33)	$ (1.42)	$ (1.52)	$ (1.83)	$ (2.46)	$ (3.24)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 1.26**	**$ 1.41**	**$ 2.89**	**$ 3.67**	**$ 6.87**	**$ 8.97**	**$ 9.82**	**$ 11.97**	**$ 16.79**	**$ 19.30**	**$ 20.97**	**$ 24.64**	**$ 28.62**	**$ 32.79**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 1.45	$ 4.74	$ 8.63	$ 13.57	$ 12.40	$ 11.49	$ 11.13	$ 10.33	$ 9.51	$ 10.05	$ 10.11	$ 10.15	$ 11.18	$ 14.79
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.34)	$ (5.28)	$ (5.15)	$ (5.07)	$ (5.16)	$ (5.59)	$ (6.15)	$ (6.36)	$ (6.60)	$ (6.81)	$ (7.36)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.66)	$ (2.45)	$ (2.89)	$ (2.93)	$ (2.79)	$ (2.53)	$ (2.20)	$ (1.83)	$ (1.46)	$ (1.08)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.93)	$ (1.35)	$ (1.65)	$ (1.57)	$ (1.34)	$ (1.22)	$ (1.24)	$ (1.38)	$ (1.48)	$ (1.53)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.45**	**$ 4.74**	**$ 8.63**	**$ 11.23**	**$ 5.53**	**$ 2.54**	**$ 1.52**	**$ 0.68**	**$ (0.20)**	**$ 0.16**	**$ 0.31**	**$ 0.34**	**$ 1.43**	**$ 4.83**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.30	$ 0.25	$ 1.51	$ 3.44	$ 7.10	$ 12.55	$ 19.93	$ 28.81	$ 39.38	$ 54.25	$ 66.49
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 4.52**	**$ 7.47**	**$ 16.21**	**$ 22.87**	**$ 17.87**	**$ 19.22**	**$ 22.47**	**$ 27.64**	**$ 37.50**	**$ 48.08**	**$ 58.82**	**$ 72.91**	**$ 91.80**	**$ 109.28**
TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.54**	**$ 122.72**	**$ 140.22**	**$ 133.88**	**$ 140.17**	**$ 158.23** **E**	**$ 181.33**	**$ 192.98**	**$ 208.77**	**$ 222.04**	**$ 244.96**	**$ 263.88**	**$ 283.86**	**$ 306.53**	**$ 328.00**	**$ 354.47**
CAGR (2019 BASE)																		6.9%
CAGR (MAY 2020 BASE)																		7.4%

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, DIRECTED METHODOLOGY

RESIDENTIAL Schedule 1 (1,000 kWh)	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 81.36	$ 81.95	$ 82.47	$ 82.29	$ 83.33	$ 88.48	$ 88.20	$ 91.38	$ 95.88	$ 97.14
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 48.31	$ 50.07	$ 51.76	$ 53.45	$ 53.45	$ 53.45	$ 53.45	$ 53.45	$ 53.45	$ 32.82
FUEL - RIDER A	$ 75.46	$ 78.85	$ 85.10	$ 87.15	$ 84.29	$ 84.41	$ 92.27	$ 97.74	$ 96.60	$ 104.34
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 0.33	$ 0.34	$ 0.35	$ 0.34	$ 0.34	$ 0.35	$ 0.36	$ 0.37	$ 0.38	$ 0.39
Generation Infrastructure										
GENERATION RIDERS [2]	$ 6.37	$ 6.58	$ 6.74	$ 6.40	$ 6.65	$ 6.54	$ 6.34	$ 6.08	$ 5.34	$ 5.43
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 7.58	$ 7.36	$ 7.07	$ 6.78	$ 6.50	$ 6.22	$ 5.96	$ 5.70	$ 5.46	$ 5.23
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 2.24	$ 2.19	$ 2.15	$ 2.10	$ 2.06	$ 2.01	$ 1.97	$ 1.92	$ 1.89	$ 1.87
Distribution Infrastructure [3]										
DISTRIBUTION RIDERS	$ 9.70	$ 9.41	$ 9.11	$ 8.81	$ 8.50	$ 8.09	$ 7.75	$ 7.32	$ 7.01	$ 6.70
A5 Environmental										
RIDER E [4]	$ 1.23	$ 1.18	$ 1.13	$ 1.08	$ 1.03	$ 0.98	$ 0.93	$ 1.00	$ 0.54	$ 0.51
RIDER CCR	$ 2.65	$ 0.37	$ 0.13	$ 0.33	$ 0.15	$ 0.01	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
INCREMENTAL GENERIC DSM	$ 8.98	$ 11.52	$ 12.73	$ 5.15	$ 3.90	$ 3.75	$ 3.96	$ 3.62	$ 3.45	$ 5.87
GENERIC GAS	$ 14.35	$ 13.99	$ 13.64	$ 13.30	$ 12.96	$ 12.63	$ 12.29	$ 11.96	$ 11.62	$ 11.29
BRUNSWICK - 2044 RETIREMENT	$ 0.18	$ 0.22	$ 0.20	$ 0.20	$ 0.28	$ 0.30	$ 0.26	$ 0.42	$ (0.29)	$ (1.95)
GREENVILLE - 2045 RETIREMENT	$ 0.22	$ 0.27	$ 0.30	$ 0.29	$ 0.35	$ 0.36	$ 0.40	$ 0.35	$ 0.65	$ 0.93
LNG - 2045 RETIREMENT	$ 0.10	$ 0.09	$ 0.08	$ 0.07	$ 0.06	$ 0.05	$ 0.05	$ 0.05	$ 0.06	$ 0.07
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ 0.09	$ 0.08	$ 0.07	$ 0.06	$ 0.05	$ 0.04	$ 0.03	$ 0.02	$ 0.01	$ (0.22)
CERC GAS CT - 2045 RETIREMENT	$ 0.42	$ 0.39	$ 0.36	$ 0.33	$ 0.31	$ 0.30	$ 0.30	$ 0.33	$ 0.43	$ (0.53)
GAS CT GENERIC - 2045 RETIREMENT	$ 0.85	$ 0.77	$ 0.68	$ 0.60	$ 0.52	$ 0.43	$ 0.35	$ 0.27	$ 0.18	$ (1.45)
RPS Program-Related Resources										
RIDER RPS [5]	$ 5.10	$ 5.04	$ 4.90	$ 4.70	$ 4.39	$ 4.59	$ 4.81	$ 5.02	$ 5.27	$ 4.15
RIDER CE [6]	$ 68.22	$ 79.19	$ 86.73	$ 93.61	$ 98.69	$ 105.61	$ 112.37	$ 120.22	$ 125.35	$ 125.65
RIDER CE - FUEL BENEFIT	$ (23.15)	$ (28.60)	$ (29.81)	$ (31.99)	$ (32.44)	$ (37.07)	$ (46.25)	$ (53.44)	$ (60.68)	$ (67.53)
RIDER CE - REC PROXY VALUE	$ (2.43)	$ (2.71)	$ (2.89)	$ (2.79)	$ (2.64)	$ (2.36)	$ (2.52)	$ (2.76)	$ (3.01)	$ (3.12)
RIDER CE - CAPACITY OFFSET	$ (4.32)	$ (5.63)	$ (6.94)	$ (8.30)	$ (9.64)	$ (10.49)	$ (11.40)	$ (12.27)	$ (13.08)	$ (12.87)
TOTAL RIDER CE	**$ 38.31**	**$ 42.25**	**$ 47.10**	**$ 50.54**	**$ 53.98**	**$ 55.69**	**$ 52.20**	**$ 51.76**	**$ 48.58**	**$ 42.13**
RIDER OSW [7]	$ 21.65	$ 20.83	$ 20.85	$ 21.29	$ 22.64	$ 25.46	$ 29.87	$ 34.42	$ 36.85	$ 44.81
RIDER OSW - FUEL BENEFIT	$ (9.61)	$ (9.97)	$ (10.39)	$ (10.86)	$ (11.48)	$ (12.36)	$ (13.27)	$ (14.29)	$ (17.04)	$ (28.88)
RIDER OSW - REC PROXY VALUE	$ (0.93)	$ (1.11)	$ (1.02)	$ (0.93)	$ (0.85)	$ (0.79)	$ (0.80)	$ (0.80)	$ (0.80)	$ (0.86)
RIDER OSW - CAPACITY OFFSET	$ (1.90)	$ (2.18)	$ (2.26)	$ (2.32)	$ (2.32)	$ (2.28)	$ (2.29)	$ (2.30)	$ (2.23)	$ (3.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 9.21**	**$ 7.57**	**$ 7.18**	**$ 7.18**	**$ 8.00**	**$ 10.02**	**$ 13.51**	**$ 17.04**	**$ 16.78**	**$ 12.06**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 79.71	$ 94.50	$ 111.75	$ 132.76	$ 156.16	$ 175.06	$ 188.82	$ 200.80	$ 237.14	$ 246.08
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 132.33**	**$ 149.35**	**$ 170.93**	**$ 195.17**	**$ 222.53**	**$ 245.36**	**$ 259.34**	**$ 274.62**	**$ 307.77**	**$ 304.42**
TOTAL	**$ 394.96**	**$ 417.16**	**$ 447.21**	**$ 466.11**	**$ 489.47**	**$ 515.99**	**$ 536.42**	**$ 558.79**	**$ 592.65**	**$ 575.07**
CAGR (2019 BASE)				6.9%						6.1%
CAGR (MAY 2020 BASE)				7.3%						6.4%

[1] Publicly available, annualized tariff rates consistent with the rebut
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and U
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all appro
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC
[6] Includes specific Company-owned projects and PPAs proposed in 2
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the o

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045

Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, DIRECTED METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033
DISTRIBUTION & GENERATION (BASE) [1]	272.78	272.78	272.78	272.78	266.31	266.31	259.72	264.59	312.72	316.26	325.85	330.78	332.75	337.82	339.19	337.19
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	-	-	-	-	(3.27)	(3.00)	-	-	-	-	-	-	-	-	-	-
TRANSMISSION - RIDER T	76.59	76.59	89.37	70.55	58.84	65.08	90.40	92.53	104.05	117.22	130.52	143.03	155.24	167.16	178.80	190.16
FUEL - RIDER A	139.52	104.14	102.13	122.69	212.27	171.52	124.41	178.08	216.68	210.78	214.42	228.94	255.88	281.55	309.74	331.99
FUEL SECURITIZATION	-	-	-	-	-	-	20.23	17.44	18.29	17.80	16.99	16.58	14.75	-	-	-
DSM	5.33	5.33	6.49	6.22	6.42	6.77	6.36	6.96	10.26	10.91	11.29	11.21	11.25	11.27	11.09	11.04
RIDER PIPP - UNIVERSAL SERVICE FEE	-	-	-	0.16	0.16	4.39	-	-	1.56	1.60	1.64	1.68	1.72	1.77	1.81	1.86
Generation Infrastructure																
GENERATION RIDERS [2]	61.54	58.22	57.99	65.89	59.26	27.33	26.51	35.96	23.91	29.28	29.34	30.74	30.96	29.80	29.66	30.70
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	-	-	-	-	8.24	4.46	5.22	15.37	17.90	18.58	22.27	26.84	32.22	35.65	37.00	37.19
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	-	-	-	-	-	-	-	-	2.75	5.32	7.27	10.30	12.77	12.49	12.20	11.87
Distribution Infrastructure [3]																
DISTRIBUTION RIDERS	8.75	5.90	5.90	9.30	15.41	10.63	26.83	26.10	34.37	37.80	41.24	43.66	46.45	43.23	41.97	40.84
A5 Environmental																
RIDER E [4]	9.44	9.44	7.48	5.99	7.76	9.77	5.48	3.07	2.68	3.35	5.28	6.04	7.78	7.58	6.83	6.53
RIDER CCR	-	-	-	17.67	17.73	14.26	7.10	7.10	10.59	14.36	14.36	14.36	14.36	14.33	14.33	14.36
RIDER RGGI	-	-	-	14.36	-	26.55	-	-	-	-	-	-	-	-	-	-
Additional Resources																
INCREMENTAL GENERIC DSM	-	-	-	-	-	-	-	-	20.45	24.65	31.24	11.87	11.78	11.88	11.86	11.59
GENERIC GAS	-	-	-	-	-	-	-	-	-	5.92	17.30	29.36	40.88	50.86	57.16	70.41
BRUNSWICK - 2044 RETIREMENT	-	-	-	-	-	-	-	-	-	0.71	0.67	0.78	0.85	0.85	0.79	0.82
GREENVILLE - 2045 RETIREMENT	-	-	-	-	-	-	-	-	0.64	0.48	2.19	1.33	0.46	1.24	1.06	1.19
LNG - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	0.54	0.72	0.67	0.67	0.64	0.59
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	-	-	-	-	-	-	-	-	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	0.06	0.70	0.65	0.61	0.56
CERC GAS CT - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	1.73	2.91	2.75	2.58	2.41
GAS CT GENERIC - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	-	-	3.34	5.54	5.16
RPS Program-Related Resources																
RIDER RPS [5]	-	-	-	1.09	10.86	7.90	28.13	46.06	31.32	37.22	46.18	47.38	50.19	52.16	52.35	51.27
RIDER CE [6]	-	-	-	0.92	7.18	14.46	17.97	27.64	54.16	67.93	82.52	99.37	131.50	158.31	179.05	209.20
RIDER CE - FUEL BENEFIT	-	-	-	-	(2.29)	(6.57)	(7.29)	(8.14)	(13.98)	(19.04)	(23.14)	(23.71)	(31.18)	(43.13)	(54.86)	(66.41)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(6.11)	(4.28)	(8.39)	(12.77)	(13.18)	(16.84)	(18.55)	(18.15)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.13)	(0.14)	-	(4.29)	(1.94)	(1.98)	(4.44)	(6.15)	(6.74)	(7.19)	(7.71)	(9.27)
TOTAL RIDER CE	**-**	**-**	**-**	**0.92**	**4.76**	**7.75**	**10.68**	**15.20**	**32.14**	**42.62**	**46.54**	**56.73**	**80.39**	**91.15**	**97.93**	**115.37**
RIDER OSW [7]	-	-	-	-	5.80	22.73	35.36	60.00	62.30	57.73	55.92	51.91	47.78	50.50	50.78	50.97
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	(12.19)	(31.39)	(30.59)	(30.10)	(30.68)	(33.19)	(36.56)	(37.77)	(39.23)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	(3.94)	(14.58)	(17.19)	(17.38)	(16.58)	(15.00)	(13.04)	(10.88)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	(4.65)	(6.76)	(8.31)	(7.89)	(6.73)	(6.11)	(6.25)	(6.91)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**5.80**	**22.73**	**35.36**	**47.81**	**22.32**	**5.79**	**0.32**	**(4.04)**	**(8.72)**	**(7.18)**	**(6.28)**	**(6.05)**
NUCLEAR SMALL MODULAR REACTORS [8]	-	-	-	-	-	-	-	1.40	1.16	7.07	16.13	33.28	58.83	93.43	135.06	184.63
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**2.01**	**21.42**	**38.38**	**74.18**	**110.48**	**86.94**	**92.71**	**109.18**	**133.34**	**180.70**	**229.55**	**279.06**	**345.21**
TOTAL	**573.95**	**532.40**	**542.13**	**587.62**	**670.55**	**642.44**	**646.43**	**757.66**	**863.78**	**907.73**	**981.60**	**1,043.35**	**1,155.08**	**1,244.43**	**1,341.92**	**1,451.68**
CAGR (2019 BASE)																
CAGR (MAY 2020 BASE)																

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045

Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045,
DIRECTED METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 326.79	$ 332.62	$ 331.32	$ 332.90	$ 334.16	$ 332.07	$ 335.72	$ 358.57	$ 355.95	$ 369.51	$ 389.25	$ 393.78
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 198.97	$ 206.32	$ 214.31	$ 222.07	$ 229.61	$ 237.10	$ 237.10	$ 237.10	$ 237.10	$ 237.10	$ 237.10	$ 158.56
FUEL - RIDER A	$ 343.22	$ 388.81	$ 452.75	$ 473.09	$ 510.57	$ 522.88	$ 505.76	$ 506.47	$ 553.61	$ 586.46	$ 579.62	$ 626.03
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 11.16	$ 11.19	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1.90	$ 1.95	$ 2.00	$ 2.05	$ 2.10	$ 2.01	$ 2.06	$ 2.12	$ 2.17	$ 2.22	$ 2.28	$ 2.34
Generation Infrastructure												
GENERATION RIDERS [2]	$ 29.84	$ 29.93	$ 29.84	$ 30.83	$ 31.61	$ 29.99	$ 31.16	$ 30.66	$ 29.72	$ 28.51	$ 25.03	$ 25.48
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 36.98	$ 36.56	$ 35.53	$ 34.49	$ 33.14	$ 31.79	$ 30.46	$ 29.16	$ 27.92	$ 26.73	$ 25.59	$ 24.52
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 10.90	$ 10.69	$ 10.49	$ 10.28	$ 10.07	$ 9.86	$ 9.65	$ 9.44	$ 9.23	$ 9.01	$ 8.84	$ 8.75
Distribution Infrastructure [3]												
DISTRIBUTION RIDERS	$ 39.67	$ 38.51	$ 37.33	$ 36.19	$ 35.05	$ 33.91	$ 32.71	$ 31.13	$ 29.83	$ 28.15	$ 26.98	$ 25.80
A5 Environmental												
RIDER E [4]	$ 6.27	$ 6.02	$ 5.78	$ 5.52	$ 5.29	$ 5.06	$ 4.84	$ 4.60	$ 4.37	$ 4.66	$ 2.53	$ 2.39
RIDER CCR	$ 23.36	$ 15.80	$ 15.91	$ 2.19	$ 0.79	$ 1.99	$ 0.87	$ 0.08	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
INCREMENTAL GENERIC DSM	$ 11.65	$ 14.21	$ 45.11	$ 57.91	$ 63.97	$ 25.88	$ 19.58	$ 18.83	$ 19.92	$ 18.20	$ 17.32	$ 29.48
GENERIC GAS	$ 70.89	$ 69.03	$ 67.27	$ 65.58	$ 63.94	$ 62.33	$ 60.76	$ 59.20	$ 57.62	$ 56.05	$ 54.49	$ 52.92
BRUNSWICK - 2044 RETIREMENT	$ 0.79	$ 0.74	$ 0.85	$ 1.03	$ 0.92	$ 0.91	$ 1.31	$ 1.40	$ 1.23	$ 1.98	$ (1.36)	$ (9.16)
GREENVILLE - 2045 RETIREMENT	$ 1.16	$ 1.13	$ 1.02	$ 1.27	$ 1.42	$ 1.36	$ 1.64	$ 1.69	$ 1.90	$ 1.64	$ 3.03	$ 4.37
LNG - 2045 RETIREMENT	$ 0.54	$ 0.49	$ 0.44	$ 0.40	$ 0.35	$ 0.31	$ 0.27	$ 0.25	$ 0.23	$ 0.23	$ 0.28	$ 0.31
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ 0.01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.02)
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ 0.51	$ 0.46	$ 0.41	$ 0.37	$ 0.32	$ 0.27	$ 0.22	$ 0.17	$ 0.13	$ 0.08	$ 0.06	$ (1.04)
CERC GAS CT - 2045 RETIREMENT	$ 2.25	$ 2.09	$ 1.94	$ 1.81	$ 1.67	$ 1.56	$ 1.46	$ 1.41	$ 1.42	$ 1.55	$ 2.01	$ (2.48)
GAS CT GENERIC - 2045 RETIREMENT	$ 4.77	$ 4.38	$ 3.98	$ 3.59	$ 3.20	$ 2.81	$ 2.42	$ 2.03	$ 1.64	$ 1.24	$ 0.85	$ (6.79)
RPS Program-Related Resources												
RIDER RPS [5]	$ 45.02	$ 31.01	$ 30.62	$ 30.24	$ 29.40	$ 28.18	$ 26.36	$ 27.52	$ 28.84	$ 30.14	$ 31.60	$ 24.89
RIDER CE [6]	$ 252.55	$ 298.11	$ 356.96	$ 415.42	$ 454.52	$ 490.14	$ 516.38	$ 554.05	$ 592.11	$ 636.02	$ 664.53	$ 666.80
RIDER CE - FUEL BENEFIT	$ (88.47)	$ (109.46)	$ (138.76)	$ (171.39)	$ (178.61)	$ (191.71)	$ (194.41)	$ (222.13)	$ (277.17)	$ (320.24)	$ (363.62)	$ (404.68)
RIDER CE - REC PROXY VALUE	$ (16.72)	$ (16.88)	$ (14.59)	$ (16.23)	$ (17.29)	$ (16.73)	$ (15.79)	$ (14.15)	$ (15.07)	$ (16.52)	$ (18.02)	$ (18.71)
RIDER CE - CAPACITY OFFSET	$ (12.44)	$ (16.39)	$ (21.89)	$ (28.51)	$ (35.15)	$ (42.05)	$ (48.85)	$ (53.14)	$ (57.75)	$ (62.15)	$ (66.27)	$ (65.22)
TOTAL RIDER CE	**$ 134.91**	**$ 155.38**	**$ 181.72**	**$ 199.29**	**$ 223.48**	**$ 239.66**	**$ 257.33**	**$ 264.63**	**$ 242.12**	**$ 237.11**	**$ 216.62**	**$ 178.19**
RIDER OSW [7]	$ 56.17	$ 74.32	$ 108.74	$ 104.63	$ 104.72	$ 106.97	$ 113.73	$ 127.90	$ 150.06	$ 172.93	$ 185.15	$ 225.10
RIDER OSW - FUEL BENEFIT	$ (40.46)	$ (43.72)	$ (57.09)	$ (59.26)	$ (61.71)	$ (64.49)	$ (68.18)	$ (73.45)	$ (78.87)	$ (84.92)	$ (101.25)	$ (171.62)
RIDER OSW - REC PROXY VALUE	$ (8.69)	$ (6.40)	$ (5.53)	$ (6.58)	$ (6.07)	$ (5.55)	$ (5.02)	$ (4.73)	$ (4.72)	$ (4.72)	$ (4.74)	$ (5.09)
RIDER OSW - CAPACITY OFFSET	$ (7.42)	$ (7.69)	$ (9.53)	$ (10.95)	$ (11.35)	$ (11.67)	$ (11.64)	$ (11.45)	$ (11.52)	$ (11.56)	$ (11.20)	$ (15.08)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (0.40)**	**$ 16.51**	**$ 36.59**	**$ 27.84**	**$ 25.60**	**$ 25.26**	**$ 28.88**	**$ 38.27**	**$ 54.95**	**$ 71.74**	**$ 67.96**	**$ 33.30**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 254.32	$ 311.70	$ 373.71	$ 443.04	$ 523.93	$ 622.39	$ 732.10	$ 820.73	$ 885.26	$ 941.41	$ 1,111.78	$ 1,153.69
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 433.85**	**$ 514.60**	**$ 622.64**	**$ 700.41**	**$ 802.40**	**$ 915.49**	**$ 1,044.67**	**$ 1,151.14**	**$ 1,211.16**	**$ 1,280.40**	**$ 1,427.96**	**$ 1,390.07**
TOTAL	**$ 1,555.48**	**$ 1,685.56**	**$ 1,890.11**	**$ 1,993.16**	**$ 2,141.75**	**$ 2,228.77**	**$ 2,333.85**	**$ 2,456.63**	**$ 2,556.31**	**$ 2,664.89**	**$ 2,813.04**	**$ 2,736.50**
CAGR (2019 BASE)		7.0%				7.0%						6.2%
CAGR (MAY 2020 BASE)		7.6%				7.6%						6.6%

[1] Publicly available, annualized tariff rates consistent with the rebut
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and L
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all appro
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC
[6] Includes specific Company-owned projects and PPAs proposed in 2
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the o

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, DIRECTED METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029
DISTRIBUTION & GENERATION (BASE) [1]	131,196.69	131,196.69	131,196.69	131,196.69	127,019.69	127,019.69	122,333.63	123,780.20	151,307.33	141,865.96	146,629.00	148,545.69
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	-	-	-	-	(1,597.09)	(1,464.00)	-	-	-	-	-	-
TRANSMISSION - RIDER T	37,760.00	37,760.00	42,270.00	45,260.00	35,280.00	47,770.00	60,900.00	63,540.00	71,440.00	80,490.00	89,620.00	98,210.00
FUEL - RIDER A	139,524.00	104,142.00	102,126.00	122,688.00	212,274.00	171,522.00	124,410.00	178,080.00	216,684.00	210,780.00	214,416.00	228,942.00
FUEL SECURITIZATION	-	-	-	-	-	-	20,226.00	17,436.00	18,288.00	17,802.00	16,992.00	16,578.00
DSM	150.00	150.00	144.00	60.00	102.00	168.00	330.00	570.00	1,050.00	1,254.00	1,326.00	1,392.00
RIDER PIPP - UNIVERSAL SERVICE FEE	-	-	-	162.00	162.00	4,392.00	-	-	1,562.82	1,600.96	1,640.24	1,680.70
Generation Infrastructure												
GENERATION RIDERS [2]	36,670.00	34,070.00	33,750.00	34,570.00	36,660.00	15,480.00	15,390.00	19,100.00	14,540.00	17,820.00	17,850.00	18,720.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	-	-	-	-	5,150.00	2,030.00	3,110.00	8,370.00	10,890.00	11,300.00	13,550.00	16,330.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	-	-	-	-	-	-	-	-	1,670.00	3,240.00	4,420.00	6,270.00
Distribution Infrastructure [3]												
DISTRIBUTION RIDERS	-	-	-	20.00	1,290.00	510.00	2,900.00	1,260.00	1,750.00	2,040.00	2,280.00	2,460.00
A5 Environmental												
RIDER E [4]	5,560.00	5,560.00	4,300.00	3,140.00	4,860.00	4,440.00	3,260.00	1,630.00	1,630.00	2,030.00	3,210.00	3,660.00
RIDER CCR	-	-	-	17,670.00	17,730.00	14,256.00	7,098.00	7,098.00	10,590.00	14,358.00	14,358.00	14,358.00
RIDER RGGI	-	-	-	14,358.00	-	26,550.00	-	-	-	-	-	-
Additional Resources												
INCREMENTAL GENERIC DSM	-	-	-	-	-	-	-	-	-	-	-	-
GENERIC GAS	-	-	-	-	-	-	-	-	-	3,600.00	10,530.00	17,860.00
BRUNSWICK - 2044 RETIREMENT	-	-	-	-	-	-	-	-	-	430.00	410.00	470.00
GREENVILLE - 2045 RETIREMENT	-	-	-	-	-	-	-	-	390.00	290.00	1,330.00	810.00
LNG - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	330.00	440.00
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	-
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	40.00
CERC GAS CT - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	1,050.00
GAS CT GENERIC - 2045 RETIREMENT	-	-	-	-	-	-	-	-	-	-	-	-
RPS Program-Related Resources												
RIDER RPS [5]	-	-	-	1,092.00	10,860.00	7,896.00	28,134.00	46,056.00	31,320.00	37,224.00	46,182.00	47,376.00
RIDER CE [6]	-	-	-	480.00	5,002.00	7,720.00	11,120.00	14,970.00	23,284.00	29,794.00	37,656.00	44,762.00
RIDER CE - FUEL BENEFIT	-	-	-	-	(2,286.00)	(6,102.00)	(7,290.00)	(7,830.00)	(10,230.00)	(13,926.00)	(16,932.00)	(17,352.00)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(4,464.00)	(3,126.00)	(6,156.00)	(9,348.00)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(80.00)	(74.00)	-	(2,180.00)	(800.00)	(820.00)	(1,840.00)	(2,570.00)
TOTAL RIDER CE	**-**	**-**	**-**	**480.00**	**2,636.00**	**1,544.00**	**3,830.00**	**4,960.00**	**7,790.00**	**11,922.00**	**12,728.00**	**15,492.00**
RIDER OSW [7]	-	-	-	-	3,470.00	10,780.00	20,750.00	33,590.00	35,100.00	32,530.00	31,510.00	29,250.00
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	(13,284.00)	(33,480.00)	(32,634.00)	(32,100.00)	(32,724.00)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	(4,206.00)	(15,558.00)	(18,342.00)	(18,540.00)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	(2,620.00)	(3,810.00)	(4,680.00)	(4,450.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**3,470.00**	**10,780.00**	**20,750.00**	**20,306.00**	**(5,206.00)**	**(19,472.00)**	**(23,612.00)**	**(26,464.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	-	-	-	-	-	-	-	750.00	710.00	4,310.00	9,820.00	20,250.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**1,572.00**	**16,966.00**	**20,220.00**	**52,714.00**	**72,072.00**	**34,614.00**	**33,984.00**	**45,118.00**	**56,654.00**
TOTAL	**350,860.69**	**312,878.69**	**313,786.69**	**370,696.69**	**455,896.60**	**432,893.69**	**412,671.63**	**492,936.20**	**536,406.15**	**542,884.92**	**584,009.24**	**634,470.39**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[6] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, DIRECTED METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040
DISTRIBUTION & GENERATION (BASE) [1]	$ 148,626.32	$ 150,571.16	$ 150,250.50	$ 147,854.63	$ 140,313.84	$ 142,638.43	$ 140,588.72	$ 140,275.01	$ 139,727.63	$ 137,126.89	$ 137,993.15
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 106,600.00	$ 114,780.00	$ 122,770.00	$ 130,570.00	$ 136,620.00	$ 141,660.00	$ 147,150.00	$ 152,480.00	$ 157,660.00	$ 162,800.00	$ 162,800.00
FUEL - RIDER A	$ 255,876.00	$ 281,550.00	$ 309,744.00	$ 331,986.00	$ 343,218.00	$ 388,806.00	$ 452,748.00	$ 473,094.00	$ 510,570.00	$ 522,882.00	$ 505,764.00
FUEL SECURITIZATION	$ 14,754.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,380.00	$ 1,368.00	$ 1,296.00	$ 1,296.00	$ 1,332.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1,722.37	$ 1,765.29	$ 1,809.50	$ 1,855.04	$ 1,901.94	$ 1,950.25	$ 2,000.01	$ 2,051.27	$ 2,104.06	$ 2,014.19	$ 2,063.88
Generation Infrastructure											
GENERATION RIDERS [2]	$ 18,830.00	$ 18,160.00	$ 18,060.00	$ 18,680.00	$ 18,140.00	$ 18,220.00	$ 18,150.00	$ 18,770.00	$ 19,240.00	$ 18,250.00	$ 18,970.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 19,600.00	$ 21,700.00	$ 22,510.00	$ 22,630.00	$ 22,510.00	$ 22,250.00	$ 21,620.00	$ 20,990.00	$ 20,160.00	$ 19,350.00	$ 18,540.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 7,770.00	$ 7,600.00	$ 7,430.00	$ 7,220.00	$ 6,630.00	$ 6,510.00	$ 6,380.00	$ 6,260.00	$ 6,130.00	$ 6,000.00	$ 5,870.00
Distribution Infrastructure [3]											
DISTRIBUTION RIDERS	$ 2,530.00	$ 2,460.00	$ 2,380.00	$ 2,320.00	$ 2,240.00	$ 2,160.00	$ 2,090.00	$ 2,020.00	$ 1,950.00	$ 1,870.00	$ 1,790.00
A5 Environmental											
RIDER E [4]	$ 4,730.00	$ 4,610.00	$ 4,160.00	$ 3,980.00	$ 3,810.00	$ 3,670.00	$ 3,520.00	$ 3,360.00	$ 3,230.00	$ 3,060.00	$ 2,930.00
RIDER CCR	$ 14,358.00	$ 14,328.00	$ 14,328.00	$ 14,358.00	$ 23,358.00	$ 15,804.00	$ 15,906.00	$ 2,190.00	$ 786.00	$ 1,986.00	$ 870.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources											
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 24,870.00	$ 30,950.00	$ 34,790.00	$ 42,850.00	$ 43,150.00	$ 42,000.00	$ 40,930.00	$ 39,910.00	$ 38,910.00	$ 37,930.00	$ 36,980.00
BRUNSWICK - 2044 RETIREMENT	$ 520.00	$ 510.00	$ 480.00	$ 500.00	$ 480.00	$ 450.00	$ 520.00	$ 620.00	$ 560.00	$ 560.00	$ 800.00
GREENVILLE - 2045 RETIREMENT	$ 280.00	$ 750.00	$ 640.00	$ 720.00	$ 710.00	$ 690.00	$ 620.00	$ 780.00	$ 860.00	$ 820.00	$ 1,000.00
LNG - 2045 RETIREMENT	$ 410.00	$ 410.00	$ 390.00	$ 360.00	$ 330.00	$ 300.00	$ 270.00	$ 240.00	$ 210.00	$ 190.00	$ 170.00
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ 430.00	$ 400.00	$ 370.00	$ 340.00	$ 310.00	$ 280.00	$ 250.00	$ 220.00	$ 190.00	$ 170.00	$ 140.00
CERC GAS CT - 2045 RETIREMENT	$ 1,770.00	$ 1,670.00	$ 1,570.00	$ 1,470.00	$ 1,370.00	$ 1,280.00	$ 1,180.00	$ 1,100.00	$ 1,020.00	$ 950.00	$ 890.00
GAS CT GENERIC - 2045 RETIREMENT	$ -	$ 2,030.00	$ 3,370.00	$ 3,140.00	$ 2,900.00	$ 2,660.00	$ 2,430.00	$ 2,190.00	$ 1,950.00	$ 1,710.00	$ 1,470.00
RPS Program-Related Resources											
RIDER RPS [5]	$ 50,190.00	$ 52,158.00	$ 52,350.00	$ 51,270.00	$ 45,018.00	$ 31,008.00	$ 30,624.00	$ 30,240.00	$ 29,400.00	$ 28,182.00	$ 26,358.00
RIDER CE [6]	$ 58,996.00	$ 70,974.00	$ 80,442.00	$ 94,020.00	$ 117,392.00	$ 141,566.00	$ 171,336.00	$ 201,450.00	$ 219,522.00	$ 235,798.00	$ 247,754.00
RIDER CE - FUEL BENEFIT	$ (22,812.00)	$ (31,566.00)	$ (40,134.00)	$ (48,594.00)	$ (64,728.00)	$ (80,088.00)	$ (101,532.00)	$ (125,400.00)	$ (130,680.00)	$ (140,274.00)	$ (142,236.00)
RIDER CE - REC PROXY VALUE	$ (9,642.00)	$ (12,318.00)	$ (13,572.00)	$ (13,278.00)	$ (12,240.00)	$ (12,336.00)	$ (10,680.00)	$ (11,880.00)	$ (12,660.00)	$ (12,228.00)	$ (11,556.00)
RIDER CE - CAPACITY OFFSET	$ (2,810.00)	$ (2,990.00)	$ (3,200.00)	$ (3,870.00)	$ (5,190.00)	$ (6,780.00)	$ (9,070.00)	$ (11,850.00)	$ (14,590.00)	$ (17,460.00)	$ (20,270.00)
TOTAL RIDER CE	**$ 23,732.00**	**$ 24,100.00**	**$ 23,536.00**	**$ 28,278.00**	**$ 35,234.00**	**$ 42,362.00**	**$ 50,054.00**	**$ 52,320.00**	**$ 61,592.00**	**$ 65,836.00**	**$ 73,692.00**
RIDER OSW [7]	$ 26,930.00	$ 28,460.00	$ 28,610.00	$ 28,720.00	$ 31,650.00	$ 41,870.00	$ 61,270.00	$ 58,950.00	$ 59,000.00	$ 60,270.00	$ 64,080.00
RIDER OSW - FUEL BENEFIT	$ (35,400.00)	$ (39,006.00)	$ (40,290.00)	$ (41,844.00)	$ (43,158.00)	$ (46,632.00)	$ (60,894.00)	$ (63,216.00)	$ (65,826.00)	$ (68,796.00)	$ (72,726.00)
RIDER OSW - REC PROXY VALUE	$ (17,694.00)	$ (16,002.00)	$ (13,914.00)	$ (11,610.00)	$ (9,270.00)	$ (6,822.00)	$ (5,904.00)	$ (7,014.00)	$ (6,480.00)	$ (5,922.00)	$ (5,358.00)
RIDER OSW - CAPACITY OFFSET	$ (3,790.00)	$ (3,450.00)	$ (3,520.00)	$ (3,900.00)	$ (4,180.00)	$ (4,330.00)	$ (5,370.00)	$ (6,170.00)	$ (6,400.00)	$ (6,580.00)	$ (6,560.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (29,954.00)**	**$ (29,998.00)**	**$ (29,114.00)**	**$ (28,634.00)**	**$ (24,958.00)**	**$ (15,914.00)**	**$ (10,898.00)**	**$ (17,450.00)**	**$ (19,706.00)**	**$ (21,028.00)**	**$ (20,564.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 35,800.00	$ 56,850.00	$ 82,190.00	$ 112,350.00	$ 154,770.00	$ 189,690.00	$ 227,420.00	$ 269,610.00	$ 318,830.00	$ 378,760.00	$ 445,520.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 79,768.00**	**$ 103,110.00**	**$ 128,962.00**	**$ 163,264.00**	**$ 210,064.00**	**$ 247,146.00**	**$ 297,200.00**	**$ 334,720.00**	**$ 390,116.00**	**$ 451,750.00**	**$ 525,006.00**
TOTAL	**$ 704,824.69**	**$ 758,722.45**	**$ 825,310.00**	**$ 895,393.67**	**$ 959,387.78**	**$ 1,039,818.68**	**$ 1,154,896.73**	**$ 1,202,614.28**	**$ 1,296,717.69**	**$ 1,370,763.08**	**$ 1,425,391.03**
CAGR (2019 BASE)						7.0%				7.1%	
CAGR (MAY 2020 BASE)						8.0%				7.8%	

[1] Publicly available, annualized tariff rates consistent with the
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4
[3] Consolidated Distribution Riders GT, U, and RBB. Includes al
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, an
[6] Includes specific Company-owned projects and PPAs propos
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - FORCED RETIREMENTS BY 2045, DIRECTED METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 150,516.73	$ 147,507.98	$ 154,317.26	$ 164,864.92	$ 166,121.33
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 162,800.00	$ 162,800.00	$ 162,800.00	$ 162,800.00	$ 88,450.00
FUEL - RIDER A	$ 506,466.00	$ 553,608.00	$ 586,458.00	$ 579,618.00	$ 626,034.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 2,115.06	$ 2,167.78	$ 2,222.08	$ 2,278.00	$ 2,335.61
Generation Infrastructure					
GENERATION RIDERS [2]	$ 18,650.00	$ 18,100.00	$ 17,350.00	$ 15,230.00	$ 15,510.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 17,750.00	$ 16,990.00	$ 16,270.00	$ 15,570.00	$ 14,920.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 5,740.00	$ 5,610.00	$ 5,480.00	$ 5,380.00	$ 5,330.00
Distribution Infrastructure [3]					
DISTRIBUTION RIDERS	$ 1,680.00	$ 1,580.00	$ 1,450.00	$ 1,360.00	$ 1,280.00
A5 Environmental					
RIDER E [4]	$ 2,790.00	$ 2,650.00	$ 2,840.00	$ 1,530.00	$ 1,450.00
RIDER CCR	$ 84.00	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -
Additional Resources					
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 36,020.00	$ 35,070.00	$ 34,110.00	$ 33,150.00	$ 32,200.00
BRUNSWICK - 2044 RETIREMENT	$ 850.00	$ 750.00	$ 1,200.00	$ (830.00)	$ (5,570.00)
GREENVILLE - 2045 RETIREMENT	$ 1,030.00	$ 1,150.00	$ 1,000.00	$ 1,840.00	$ 2,660.00
LNG - 2045 RETIREMENT	$ 150.00	$ 140.00	$ 140.00	$ 170.00	$ 190.00
ENVIRONMENTAL (Clover Legacy) - 2041 RETIREMENT	$ -	$ (10.00)	$ (10.00)	$ (10.00)	$ (10.00)
ENVIRONMENTAL (MATs & 111d) - 2045 RETIREMENT	$ 110.00	$ 80.00	$ 50.00	$ 40.00	$ (640.00)
CERC GAS CT - 2045 RETIREMENT	$ 860.00	$ 870.00	$ 950.00	$ 1,220.00	$ (1,510.00)
GAS CT GENERIC - 2045 RETIREMENT	$ 1,230.00	$ 1,000.00	$ 760.00	$ 520.00	$ (4,130.00)
RPS Program-Related Resources					
RIDER RPS [5]	$ 27,516.00	$ 28,836.00	$ 30,144.00	$ 31,602.00	$ 24,894.00
RIDER CE [6]	$ 268,730.00	$ 292,318.00	$ 319,054.00	$ 336,002.00	$ 338,434.00
RIDER CE - FUEL BENEFIT	$ (162,522.00)	$ (202,794.00)	$ (234,324.00)	$ (266,052.00)	$ (296,100.00)
RIDER CE - REC PROXY VALUE	$ (10,356.00)	$ (11,028.00)	$ (12,084.00)	$ (13,200.00)	$ (13,692.00)
RIDER CE - CAPACITY OFFSET	$ (22,030.00)	$ (23,980.00)	$ (25,780.00)	$ (27,480.00)	$ (27,070.00)
TOTAL RIDER CE	**$ 73,822.00**	**$ 54,516.00**	**$ 46,866.00**	**$ 29,270.00**	**$ 1,572.00**
RIDER OSW [7]	$ 72,070.00	$ 84,550.00	$ 97,440.00	$ 104,320.00	$ 126,830.00
RIDER OSW - FUEL BENEFIT	$ (78,348.00)	$ (84,132.00)	$ (90,582.00)	$ (108,000.00)	$ (183,066.00)
RIDER OSW - REC PROXY VALUE	$ (5,040.00)	$ (5,034.00)	$ (5,034.00)	$ (5,052.00)	$ (5,430.00)
RIDER OSW - CAPACITY OFFSET	$ (6,450.00)	$ (6,490.00)	$ (6,510.00)	$ (6,310.00)	$ (8,490.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (17,768.00)**	**$ (11,106.00)**	**$ (4,686.00)**	**$ (15,042.00)**	**$ (70,156.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 499,460.00	$ 538,730.00	$ 572,890.00	$ 676,570.00	$ 702,080.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 583,030.00**	**$ 610,976.00**	**$ 645,214.00**	**$ 722,400.00**	**$ 658,390.00**
TOTAL	**$ 1,493,215.79**	**$ 1,562,383.76**	**$ 1,633,945.34**	**$ 1,708,474.92**	**$ 1,604,354.94**
CAGR (2019 BASE)					6.0%
CAGR (MAY 2020 BASE)					6.6%

[1] Publicly available, annualized tariff rates consistent with the
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4
[3] Consolidated Distribution Riders GT, U, and RBB. Includes al
[4] Inclusive of MATs and 111d compliance cost.
[5] Includes the cost of REC purchases, deficiency payments, an
[6] Includes specific Company-owned projects and PPAs propos
[7] No assumptions modeled for exemptions to Riders OSW.
[8] While nuclear small modular reactors do not generate RECs

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - LEAST COST VCEA COMPLIANT WITHOUT EPA, DIRECTED METHODOLOGY

RESIDENTIAL	2019	2020	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Schedule 1 (1,000 kWh)	DEC 2019	MAY 1, 2020	DEC 2020	DEC 2021	DEC 2022	DEC 2023	DEC 2024	DEC 2025	DEC 2026	DEC 2027	DEC 2028	DEC 2029	DEC 2030	DEC 2031	DEC 2032	DEC 2033	DEC 2034	DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 60.93	$ 60.93	$ 60.71	$ 60.71	$ 73.57	$ 76.09	$ 78.35	$ 79.61	$ 80.25	$ 81.90	$ 82.34	$ 82.10	$ 81.63	$ 82.93
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (0.47)	$ (0.43)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	$ 12.91	$ 15.58	$ 19.40	$ 21.49	$ 23.42	$ 26.45	$ 29.74	$ 33.02	$ 36.30	$ 39.17	$ 41.82	$ 44.52	$ 47.14	$ 49.16
FUEL - RIDER A	$ 23.25	$ 17.36	$ 17.02	$ 20.45	$ 35.38	$ 28.59	$ 20.74	$ 29.68	$ 36.11	$ 35.12	$ 35.68	$ 36.22	$ 39.04	$ 40.01	$ 42.21	$ 44.77	$ 46.74	$ 51.51
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.37	$ 2.91	$ 3.05	$ 2.97	$ 2.83	$ 2.76	$ 2.46	$ -	$ -	$ -	$ -	$ -
DSM	$ 1.13	$ 1.13	$ 1.47	$ 1.31	$ 1.60	$ 1.84	$ 1.55	$ 1.57	$ 2.04	$ 2.17	$ 2.25	$ 2.23	$ 2.24	$ 2.24	$ 2.21	$ 2.20	$ 2.22	$ 2.23
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 0.03	$ 0.03	$ 0.73	$ -	$ -	$ 0.26	$ 0.27	$ 0.27	$ 0.28	$ 0.29	$ 0.29	$ 0.30	$ 0.31	$ 0.32	$ 0.33
Generation Infrastructure																		
GENERATION RIDERS [2]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	$ 14.51	$ 6.67	$ 6.58	$ 7.57	$ 5.10	$ 6.25	$ 6.26	$ 6.54	$ 6.54	$ 6.29	$ 6.25	$ 6.43	$ 6.22	$ 6.22
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 2.07	$ 0.93	$ 1.29	$ 3.48	$ 3.82	$ 3.96	$ 4.75	$ 5.72	$ 6.87	$ 7.60	$ 7.89	$ 7.93	$ 7.89	$ 7.80
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.59	$ 1.14	$ 1.55	$ 2.20	$ 2.72	$ 2.66	$ 2.60	$ 2.53	$ 2.32	$ 2.28
Distribution Infrastructure [3]																		
DISTRIBUTION RIDERS	$ 1.84	$ 1.40	$ 1.40	$ 2.16	$ 3.84	$ 2.53	$ 7.81	$ 6.77	$ 8.93	$ 9.82	$ 10.72	$ 11.35	$ 12.07	$ 11.24	$ 10.91	$ 10.61	$ 10.31	$ 10.01
A5 Environmental																		
RIDER E	$ 1.99	$ 1.99	$ 1.67	$ 1.25	$ 1.95	$ 2.03	$ 1.35	$ 0.64	$ 0.57	$ 0.65	$ 0.59	$ 0.71	$ 0.74	$ 0.72	$ 0.56	$ 0.53	$ 0.51	$ 0.48
RIDER CCR	$ -	$ -	$ -	$ 2.95	$ 2.96	$ 2.38	$ 1.18	$ 1.18	$ 1.77	$ 2.39	$ 2.39	$ 2.39	$ 2.39	$ 2.39	$ 2.39	$ 2.39	$ 3.89	$ 2.63
RIDER RGGI	$ -	$ -	$ -	$ 2.39	$ -	$ 4.64	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.07	$ 4.91	$ 6.22	$ 2.36	$ 2.34	$ 2.36	$ 2.36	$ 2.31	$ 2.32	$ 2.83
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.26	$ 3.70	$ 6.45	$ 9.65	$ 13.48	$ 17.86	$ 26.62	$ 30.42	$ 32.55
RPS Program-Related Resources																		
RIDER RPS [4]	$ -	$ -	$ -	$ 0.18	$ 1.81	$ 1.32	$ 4.69	$ 7.68	$ 5.22	$ 6.21	$ 7.99	$ 8.56	$ 9.46	$ 10.60	$ 11.43	$ 11.66	$ 11.97	$ 12.78
RIDER CE [5]	$ -	$ -	$ -	$ 0.19	$ 1.67	$ 2.59	$ 4.10	$ 6.17	$ 10.61	$ 13.12	$ 15.78	$ 18.99	$ 25.23	$ 30.67	$ 34.88	$ 39.20	$ 43.70	$ 48.21
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.38)	$ (1.15)	$ (1.22)	$ (1.55)	$ (2.33)	$ (3.18)	$ (3.83)	$ (3.91)	$ (5.62)	$ (7.14)	$ (8.41)	$ (10.19)	$ (11.64)	$ (13.04)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.02)	$ (0.72)	$ (1.40)	$ (2.21)	$ (2.40)	$ (3.53)	$ (4.40)	$ (4.93)	$ (5.13)	$ (5.20)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.03)	$ (0.03)	$ -	$ (0.96)	$ (0.38)	$ (0.39)	$ (0.88)	$ (1.21)	$ (1.33)	$ (1.48)	$ (1.65)	$ (1.94)	$ (2.34)	$ (2.71)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 1.26**	**$ 1.41**	**$ 2.89**	**$ 3.67**	**$ 6.87**	**$ 8.83**	**$ 9.68**	**$ 11.65**	**$ 15.88**	**$ 18.53**	**$ 20.42**	**$ 22.14**	**$ 24.58**	**$ 27.26**
RIDER OSW [6]	$ -	$ -	$ -	$ -	$ 1.45	$ 4.74	$ 8.63	$ 13.57	$ 12.40	$ 11.49	$ 11.13	$ 10.33	$ 9.51	$ 10.05	$ 10.76	$ 10.90	$ 12.83	$ 18.16
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.34)	$ (5.28)	$ (5.14)	$ (5.03)	$ (5.09)	$ (5.05)	$ (4.93)	$ (4.93)	$ (5.03)	$ (5.15)	$ (5.48)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.66)	$ (2.45)	$ (2.97)	$ (3.12)	$ (3.11)	$ (3.00)	$ (2.86)	$ (2.63)	$ (2.39)	$ (2.13)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.93)	$ (1.35)	$ (1.65)	$ (1.57)	$ (1.37)	$ (1.37)	$ (1.42)	$ (1.51)	$ (1.52)	$ (1.48)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.45**	**$ 4.74**	**$ 8.63**	**$ 11.23**	**$ 5.53**	**$ 2.56**	**$ 1.48**	**$ 0.55**	**$ (0.02)**	**$ 0.75**	**$ 1.56**	**$ 1.72**	**$ 3.78**	**$ 9.08**
NUCLEAR SMALL MODULAR REACTORS [7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.30	$ 0.25	$ 0.09	$ 0.05	$ 0.05	$ -	$ -	$ -	$ -	$ 0.17	$ 0.52
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 4.52**	**$ 7.47**	**$ 16.21**	**$ 22.87**	**$ 17.87**	**$ 17.68**	**$ 19.20**	**$ 20.81**	**$ 25.32**	**$ 29.88**	**$ 33.40**	**$ 35.52**	**$ 40.50**	**$ 49.64**
TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.54**	**$ 122.72**	**$ 140.22**	**$ 133.88**	**$ 140.17**	**$ 158.86**	**$ 181.16**	**$ 191.13**	**$ 204.49**	**$ 212.66**	**$ 229.23**	**$ 240.22**	**$ 253.12**	**$ 268.77**	**$ 282.43**	**$ 300.60**
CAGR (2019 BASE)																		5.8%
CAGR (MAY 2020 BASE)																		6.3%

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[5] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - LEAST COST VCEA COMPLIANT WITHOUT EPA, DIRECTED METHODOLOGY

RESIDENTIAL Schedule 1 (1,000 kWh)	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 83.54	$ 83.51	$ 83.30	$ 86.04	$ 87.02	$ 89.97	$ 91.52	$ 93.46	$ 95.06	$ 97.02
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 50.82	$ 52.64	$ 54.41	$ 56.13	$ 57.80	$ 59.41	$ 60.98	$ 62.49	$ 63.95	$ 40.13
FUEL - RIDER A	$ 57.18	$ 60.58	$ 64.48	$ 70.98	$ 77.02	$ 86.99	$ 96.71	$ 106.49	$ 118.67	$ 128.97
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 0.33	$ 0.34	$ 0.35	$ 0.34	$ 0.34	$ 0.35	$ 0.36	$ 0.37	$ 0.38	$ 0.39
Generation Infrastructure										
GENERATION RIDERS [2]	$ 6.18	$ 6.39	$ 6.57	$ 6.24	$ 6.50	$ 6.39	$ 6.19	$ 5.94	$ 5.23	$ 5.41
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 7.58	$ 7.36	$ 7.07	$ 6.78	$ 6.50	$ 6.22	$ 5.96	$ 5.70	$ 5.46	$ 5.23
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 2.24	$ 2.19	$ 2.15	$ 2.10	$ 2.06	$ 2.01	$ 1.97	$ 1.92	$ 1.89	$ 1.87
Distribution Infrastructure [3]										
DISTRIBUTION RIDERS	$ 9.70	$ 9.41	$ 9.11	$ 8.81	$ 8.50	$ 8.09	$ 7.75	$ 7.32	$ 7.01	$ 6.70
A5 Environmental										
RIDER E	$ 0.46	$ 0.44	$ 0.42	$ 0.40	$ 0.38	$ 0.36	$ 0.34	$ 0.52	$ 0.15	$ 0.14
RIDER CCR	$ 2.65	$ 0.37	$ 0.13	$ 0.33	$ 0.15	$ 0.01	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
INCREMENTAL GENERIC DSM	$ 8.98	$ 11.52	$ 12.73	$ 5.15	$ 3.90	$ 3.75	$ 3.96	$ 3.62	$ 3.45	$ 5.87
GENERIC GAS	$ 32.71	$ 32.64	$ 32.27	$ 31.41	$ 30.59	$ 29.78	$ 28.98	$ 28.18	$ 27.40	$ 26.61
RPS Program-Related Resources										
RIDER RPS [4]	$ 13.28	$ 14.92	$ 16.47	$ 17.64	$ 15.00	$ 17.59	$ 20.32	$ 21.86	$ 23.58	$ 26.18
RIDER CE [5]	$ 52.52	$ 56.73	$ 59.65	$ 61.83	$ 63.45	$ 64.73	$ 64.99	$ 66.41	$ 67.53	$ 69.06
RIDER CE - FUEL BENEFIT	$ (14.73)	$ (16.88)	$ (19.51)	$ (22.43)	$ (24.77)	$ (29.87)	$ (36.43)	$ (42.31)	$ (50.54)	$ (56.57)
RIDER CE - REC PROXY VALUE	$ (5.11)	$ (5.19)	$ (5.15)	$ (5.03)	$ (4.80)	$ (4.43)	$ (4.43)	$ (4.38)	$ (4.28)	$ (4.13)
RIDER CE - CAPACITY OFFSET	$ (3.08)	$ (3.44)	$ (3.79)	$ (4.07)	$ (4.22)	$ (4.14)	$ (4.06)	$ (3.79)	$ (3.67)	$ (3.46)
TOTAL RIDER CE	**$ 29.60**	**$ 31.22**	**$ 31.20**	**$ 30.30**	**$ 29.67**	**$ 26.28**	**$ 20.07**	**$ 15.93**	**$ 9.04**	**$ 4.90**
RIDER OSW [6]	$ 27.94	$ 31.57	$ 35.59	$ 37.62	$ 44.50	$ 42.55	$ 41.20	$ 40.04	$ 39.04	$ 38.72
RIDER OSW - FUEL BENEFIT	$ (7.20)	$ (7.56)	$ (7.96)	$ (9.45)	$ (16.02)	$ (17.86)	$ (19.97)	$ (22.45)	$ (25.17)	$ (27.57)
RIDER OSW - REC PROXY VALUE	$ (2.01)	$ (2.36)	$ (2.14)	$ (1.92)	$ (1.84)	$ (2.74)	$ (2.59)	$ (2.43)	$ (2.26)	$ (2.09)
RIDER OSW - CAPACITY OFFSET	$ (1.82)	$ (2.10)	$ (2.18)	$ (2.26)	$ (3.37)	$ (4.17)	$ (4.25)	$ (4.33)	$ (4.38)	$ (4.44)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 16.91**	**$ 19.55**	**$ 23.30**	**$ 23.99**	**$ 23.29**	**$ 17.78**	**$ 14.39**	**$ 10.84**	**$ 7.23**	**$ 4.62**
NUCLEAR SMALL MODULAR REACTORS [7]	$ 1.28	$ 2.66	$ 4.66	$ 7.21	$ 9.96	$ 12.79	$ 16.27	$ 17.88	$ 18.61	$ 17.75
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 61.06**	**$ 68.35**	**$ 75.63**	**$ 79.13**	**$ 77.91**	**$ 74.44**	**$ 71.06**	**$ 66.50**	**$ 58.46**	**$ 53.45**
TOTAL	**$ 325.65**	**$ 337.94**	**$ 350.83**	**$ 356.07**	**$ 360.88**	**$ 369.99**	**$ 377.99**	**$ 384.73**	**$ 389.32**	**$ 374.01**
CAGR (2019 BASE)				5.5%						4.4%
CAGR (MAY 2020 BASE)				5.9%						4.7%

[1] Publicly available, annualized tariff rates consistent with the rebut
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and U
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all appr
[4] Includes the cost of REC purchases, deficiency payments, and REC
[5] Includes specific Company-owned projects and PPAs proposed in 2
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the o

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - LEAST COST VCEA COMPLIANT WITHOUT EPA, DIRECTED METHODOLOGY

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 312.72	$ 316.26	$ 325.85	$ 330.78	$ 332.75	$ 339.44
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 95.33	$ 103.90	$ 117.31	$ 131.90	$ 146.48	$ 161.02	$ 173.74
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 178.08	$ 216.67	$ 210.70	$ 214.05	$ 217.33	$ 234.21	$ 240.04
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 17.44	$ 18.29	$ 17.80	$ 16.99	$ 16.58	$ 14.75	$ -
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 6.77	$ 6.36	$ 6.96	$ 10.26	$ 10.91	$ 11.29	$ 11.21	$ 11.25	$ 11.27
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ 1.56	$ 1.60	$ 1.64	$ 1.68	$ 1.72	$ 1.77
Generation Infrastructure														
GENERATION RIDERS [2]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 35.96	$ 23.91	$ 29.28	$ 29.33	$ 30.65	$ 30.68	$ 29.50
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 15.37	$ 17.90	$ 18.58	$ 22.27	$ 26.84	$ 32.22	$ 35.65
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.75	$ 5.32	$ 7.27	$ 10.30	$ 12.77	$ 12.49
Distribution Infrastructure [3]														
DISTRIBUTION RIDERS	$ 8.75	$ 5.90	$ 5.90	$ 9.30	$ 15.41	$ 10.63	$ 26.83	$ 26.10	$ 34.37	$ 37.80	$ 41.24	$ 43.66	$ 46.45	$ 43.23
A5 Environmental														
RIDER E	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.07	$ 2.68	$ 3.05	$ 2.75	$ 3.34	$ 3.49	$ 3.35
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.10	$ 7.10	$ 10.59	$ 14.36	$ 14.36	$ 14.36	$ 14.36	$ 14.33
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 26.55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources														
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.45	$ 24.65	$ 31.24	$ 11.87	$ 11.78	$ 11.88
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.92	$ 17.34	$ 30.21	$ 45.22	$ 63.18
RPS Program-Related Resources														
RIDER RPS [4]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 46.06	$ 31.33	$ 37.24	$ 47.95	$ 51.37	$ 56.77	$ 63.62
RIDER CE [5]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.46	$ 17.97	$ 27.64	$ 54.16	$ 67.27	$ 81.65	$ 97.99	$ 130.84	$ 159.58
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.14)	$ (13.98)	$ (19.04)	$ (22.93)	$ (23.45)	$ (33.67)	$ (42.77)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.11)	$ (4.28)	$ (8.39)	$ (13.27)	$ (14.39)	$ (21.17)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (1.94)	$ (1.98)	$ (4.44)	$ (6.15)	$ (6.73)	$ (7.47)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.75**	**$ 10.68**	**$ 15.20**	**$ 32.14**	**$ 41.96**	**$ 45.89**	**$ 55.12**	**$ 76.04**	**$ 88.17**
RIDER OSW [6]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 60.00	$ 62.30	$ 57.73	$ 55.92	$ 51.91	$ 47.78	$ 50.50
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12.19)	$ (31.38)	$ (30.52)	$ (29.87)	$ (30.24)	$ (29.99)	$ (29.30)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3.94)	$ (14.58)	$ (17.63)	$ (18.56)	$ (18.50)	$ (17.85)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4.65)	$ (6.76)	$ (8.31)	$ (7.89)	$ (6.90)	$ (6.88)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 47.81**	**$ 22.33**	**$ 5.87**	**$ 0.10**	**$ (4.78)**	**$ (7.60)**	**$ (3.53)**
NUCLEAR SMALL MODULAR REACTORS [7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.40	$ 1.16	$ 0.41	$ 0.23	$ 0.23	$ -	$ -
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.38**	**$ 74.18**	**$ 110.48**	**$ 86.95**	**$ 85.48**	**$ 94.18**	**$ 101.95**	**$ 125.21**	**$ 148.25**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 642.44**	**$ 646.43**	**$ 760.47**	**$ 862.99**	**$ 899.01**	**$ 961.70**	**$ 997.24**	**$ 1,077.87**	**$ 1,128.11**
CAGR (2019 BASE)														
CAGR (MAY 2020 BASE)														

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[5] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

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SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044
DISTRIBUTION & GENERATION (BASE) [1]	$ 340.43	$ 338.18	$ 334.90	$ 339.85	$ 341.56	$ 340.23	$ 338.06	$ 349.66	$ 353.02	$ 365.53	$ 371.52	$ 379.29	$ 385.41
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 185.50	$ 197.45	$ 209.11	$ 218.04	$ 225.41	$ 233.50	$ 241.34	$ 248.97	$ 256.37	$ 263.54	$ 270.47	$ 277.19	$ 283.67
FUEL - RIDER A	$ 253.28	$ 268.63	$ 280.43	$ 309.08	$ 343.07	$ 363.45	$ 386.86	$ 425.89	$ 462.09	$ 521.92	$ 580.28	$ 638.92	$ 712.02
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 11.09	$ 11.04	$ 11.16	$ 11.19	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18	$ 11.18
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1.81	$ 1.86	$ 1.90	$ 1.95	$ 2.00	$ 2.05	$ 2.10	$ 2.01	$ 2.06	$ 2.12	$ 2.17	$ 2.22	$ 2.28
Generation Infrastructure													
GENERATION RIDERS [2]	$ 29.30	$ 30.15	$ 29.17	$ 29.18	$ 28.97	$ 29.94	$ 30.78	$ 29.24	$ 30.48	$ 29.97	$ 29.03	$ 27.86	$ 24.52
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 37.00	$ 37.19	$ 36.98	$ 36.56	$ 35.53	$ 34.49	$ 33.14	$ 31.79	$ 30.46	$ 29.16	$ 27.92	$ 26.73	$ 25.59
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 12.20	$ 11.87	$ 10.90	$ 10.69	$ 10.49	$ 10.28	$ 10.07	$ 9.86	$ 9.65	$ 9.44	$ 9.23	$ 9.01	$ 8.84
Distribution Infrastructure [3]													
DISTRIBUTION RIDERS	$ 41.97	$ 40.84	$ 39.67	$ 38.51	$ 37.33	$ 36.19	$ 35.05	$ 33.91	$ 32.71	$ 31.13	$ 29.83	$ 28.15	$ 26.98
A5 Environmental													
RIDER E	$ 2.63	$ 2.47	$ 2.36	$ 2.27	$ 2.17	$ 2.05	$ 1.96	$ 1.87	$ 1.78	$ 1.67	$ 1.58	$ 2.42	$ 0.69
RIDER CCR	$ 14.33	$ 14.36	$ 23.36	$ 15.80	$ 15.91	$ 2.19	$ 0.79	$ 1.99	$ 0.87	$ 0.08	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources													
INCREMENTAL GENERIC DSM	$ 11.86	$ 11.59	$ 11.65	$ 14.21	$ 45.11	$ 57.91	$ 63.97	$ 25.88	$ 19.58	$ 18.83	$ 19.92	$ 18.20	$ 17.32
GENERIC GAS	$ 83.74	$ 124.81	$ 142.60	$ 152.59	$ 153.35	$ 153.01	$ 151.30	$ 147.28	$ 143.41	$ 139.61	$ 135.85	$ 132.13	$ 128.44
RPS Program-Related Resources													
RIDER RPS [4]	$ 68.55	$ 69.93	$ 71.82	$ 76.69	$ 79.66	$ 89.51	$ 98.80	$ 105.81	$ 89.98	$ 105.56	$ 121.94	$ 131.13	$ 141.50
RIDER CE [5]	$ 182.03	$ 205.06	$ 228.97	$ 252.93	$ 275.80	$ 298.31	$ 314.39	$ 326.74	$ 337.09	$ 345.70	$ 349.22	$ 358.65	$ 366.59
RIDER CE - FUEL BENEFIT	$ (50.38)	$ (61.04)	$ (69.78)	$ (78.16)	$ (88.27)	$ (101.13)	$ (116.90)	$ (134.43)	$ (148.41)	$ (179.03)	$ (218.29)	$ (253.53)	$ (302.83)
RIDER CE - REC PROXY VALUE	$ (26.36)	$ (29.56)	$ (30.77)	$ (31.16)	$ (30.63)	$ (31.10)	$ (30.87)	$ (30.13)	$ (28.76)	$ (26.56)	$ (26.53)	$ (26.24)	$ (25.67)
RIDER CE - CAPACITY OFFSET	$ (8.35)	$ (9.83)	$ (11.87)	$ (13.75)	$ (15.59)	$ (17.43)	$ (19.22)	$ (20.65)	$ (21.37)	$ (20.99)	$ (20.59)	$ (19.21)	$ (18.61)
TOTAL RIDER CE	**$ 96.94**	**$ 104.62**	**$ 116.54**	**$ 129.85**	**$ 141.31**	**$ 148.66**	**$ 147.40**	**$ 141.53**	**$ 138.55**	**$ 119.12**	**$ 83.82**	**$ 59.66**	**$ 19.48**
RIDER OSW [6]	$ 54.06	$ 54.77	$ 64.45	$ 91.22	$ 140.36	$ 158.61	$ 178.78	$ 189.01	$ 223.58	$ 213.78	$ 206.99	$ 201.16	$ 196.16
RIDER OSW - FUEL BENEFIT	$ (29.26)	$ (29.90)	$ (30.61)	$ (32.53)	$ (42.78)	$ (44.94)	$ (47.29)	$ (56.15)	$ (95.17)	$ (106.15)	$ (118.69)	$ (133.39)	$ (149.57)
RIDER OSW - REC PROXY VALUE	$ (16.99)	$ (15.65)	$ (14.18)	$ (12.63)	$ (11.92)	$ (14.02)	$ (12.74)	$ (11.42)	$ (10.91)	$ (16.28)	$ (15.36)	$ (14.41)	$ (13.45)
RIDER OSW - CAPACITY OFFSET	$ (7.15)	$ (7.61)	$ (7.61)	$ (7.42)	$ (9.16)	$ (10.55)	$ (10.94)	$ (11.35)	$ (16.91)	$ (20.95)	$ (21.35)	$ (21.74)	$ (21.98)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 0.67**	**$ 1.61**	**$ 12.05**	**$ 38.64**	**$ 76.50**	**$ 89.10**	**$ 107.80**	**$ 110.09**	**$ 100.60**	**$ 70.41**	**$ 51.59**	**$ 31.62**	**$ 11.15**
NUCLEAR SMALL MODULAR REACTORS [7]	$ -	$ -	$ 0.82	$ 2.41	$ 5.99	$ 12.49	$ 21.86	$ 33.80	$ 46.71	$ 59.94	$ 76.28	$ 83.80	$ 87.24
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 166.15**	**$ 176.16**	**$ 201.22**	**$ 247.60**	**$ 303.46**	**$ 339.76**	**$ 375.86**	**$ 391.23**	**$ 375.83**	**$ 355.03**	**$ 333.63**	**$ 306.22**	**$ 259.38**
TOTAL	**$ 1,191.29**	**$ 1,266.61**	**$ 1,335.41**	**$ 1,427.53**	**$ 1,555.53**	**$ 1,616.23**	**$ 1,682.44**	**$ 1,710.76**	**$ 1,729.48**	**$ 1,779.21**	**$ 1,822.61**	**$ 1,859.53**	**$ 1,886.33**
CAGR (2019 BASE)				5.9%				5.6%					
CAGR (MAY 2020 BASE)				6.5%				6.1%					

[1] Publicly available, annualized tariff rates consistent with the rebut
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and U
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all appr
[4] Includes the cost of REC purchases, deficiency payments, and REC
[5] Includes specific Company-owned projects and PPAs proposed in 2
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the o

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL SERVICE		2045
Schedule GS-1 (6,000 kWh - 15 kW)		DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$	393.26
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$	-
TRANSMISSION - RIDER T	$	193.88
FUEL - RIDER A	$	773.84
FUEL SECURITIZATION	$	-
DSM	$	11.18
RIDER PIPP - UNIVERSAL SERVICE FEE	$	2.34
Generation Infrastructure		
GENERATION RIDERS [2]	$	25.34
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$	24.52
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$	8.75
Distribution Infrastructure [3]		
DISTRIBUTION RIDERS	$	25.80
A5 Environmental		
RIDER E	$	0.64
RIDER CCR	$	-
RIDER RGGI	$	-
Additional Resources		
INCREMENTAL GENERIC DSM	$	29.48
GENERIC GAS	$	124.76
RPS Program-Related Resources		
RIDER RPS [4]	$	157.07
RIDER CE [5]	$	376.58
RIDER CE - FUEL BENEFIT	$	(338.98)
RIDER CE - REC PROXY VALUE	$	(24.74)
RIDER CE - CAPACITY OFFSET	$	(17.53)
TOTAL RIDER CE	**$**	**(4.67)**
RIDER OSW [6]	$	194.52
RIDER OSW - FUEL BENEFIT	$	(163.79)
RIDER OSW - REC PROXY VALUE	$	(12.43)
RIDER OSW - CAPACITY OFFSET	$	(22.29)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$**	**(4.00)**
NUCLEAR SMALL MODULAR REACTORS [7]	$	83.21
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$**	**231.61**
TOTAL	**$**	**1,845.41**
CAGR (2019 BASE)		4.6%
CAGR (MAY 2020 BASE)		5.0%

[1] Publicly available, annualized tariff rates consistent with the rebut
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and U
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all appr
[4] Includes the cost of REC purchases, deficiency payments, and REC
[5] Includes specific Company-owned projects and PPAs proposed in 2
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the o

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
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LARGE GENERAL BILL PROJECTION - LEAST COST VCEA COMPLIANT WITHOUT EPA, DIRECTED METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 127,019.69	$ 127,019.69	$ 122,333.63	$ 123,780.20	$ 151,307.33	$ 141,865.96	$ 146,629.00
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ (1,597.09)	$ (1,464.00)	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 37,760.00	$ 37,760.00	$ 42,270.00	$ 45,260.00	$ 35,280.00	$ 47,770.00	$ 60,900.00	$ 65,460.00	$ 71,340.00	$ 80,550.00	$ 90,570.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 178,080.00	$ 216,672.00	$ 210,702.00	$ 214,050.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,226.00	$ 17,436.00	$ 18,288.00	$ 17,802.00	$ 16,992.00
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 330.00	$ 570.00	$ 1,050.00	$ 1,254.00	$ 1,326.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ 1,562.82	$ 1,600.96	$ 1,640.24
Generation Infrastructure											
GENERATION RIDERS [2]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 19,100.00	$ 14,540.00	$ 17,820.00	$ 17,850.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 8,370.00	$ 10,890.00	$ 11,300.00	$ 13,550.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,670.00	$ 3,240.00	$ 4,420.00
Distribution Infrastructure [3]											
DISTRIBUTION RIDERS	$ -	$ -	$ -	$ 20.00	$ 1,290.00	$ 510.00	$ 2,900.00	$ 1,260.00	$ 1,750.00	$ 2,040.00	$ 2,280.00
A5 Environmental											
RIDER E	$ 5,560.00	$ 5,560.00	$ 4,300.00	$ 3,140.00	$ 4,860.00	$ 4,440.00	$ 3,260.00	$ 1,630.00	$ 1,630.00	$ 1,850.00	$ 1,670.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,098.00	$ 7,098.00	$ 10,590.00	$ 14,358.00	$ 14,358.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 26,550.00	$ -	$ -	$ -	$ -	$ -
Additional Resources											
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,600.00	$ 10,550.00
RPS Program-Related Resources											
RIDER RPS [4]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 46,056.00	$ 31,326.00	$ 37,236.00	$ 47,952.00
RIDER CE [5]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 14,970.00	$ 23,284.00	$ 29,524.00	$ 37,296.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (7,830.00)	$ (10,230.00)	$ (13,938.00)	$ (16,794.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,464.00)	$ (3,126.00)	$ (6,156.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (800.00)	$ (820.00)	$ (1,840.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,960.00**	**$ 7,790.00**	**$ 11,640.00**	**$ 12,506.00**
RIDER OSW [6]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 33,590.00	$ 35,100.00	$ 32,530.00	$ 31,510.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,284.00)	$ (33,468.00)	$ (32,550.00)	$ (31,866.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,206.00)	$ (15,552.00)	$ (18,810.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,620.00)	$ (3,810.00)	$ (4,680.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 20,306.00**	**$ (5,194.00)**	**$ (19,382.00)**	**$ (23,846.00)**
NUCLEAR SMALL MODULAR REACTORS [7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 750.00	$ 710.00	$ 250.00	$ 140.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 72,072.00**	**$ 34,632.00**	**$ 29,744.00**	**$ 36,752.00**
TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 432,893.69**	**$ 412,671.63**	**$ 494,856.20**	**$ 535,922.15**	**$ 537,726.92**	**$ 572,637.24**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

[1] Publicly available, annualized tariff rates consistent with the rebuttal position in Case No. PUR-2024-00058. Inclusive of capacity and an annual inflation rate of 2%.
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, and LNG. Riders R, S, and W rolled into base rates effective July 1, 2023.
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all approved (as of August 2025) and projected phases of distribution infrastructure.
[4] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[5] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, the output from such facilities reduces the Company's RPS Program annual requirement.

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
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LARGE GENERAL BILL PROJECTION - LEAST COST VCEA COMPLIANT WITHOUT EPA, DIRECTED METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035	2036 DEC 2036	2037 DEC 2037	2038 DEC 2038
DISTRIBUTION & GENERATION (BASE) [1]	$ 148,545.69	$ 148,626.32	$ 151,561.16	$ 151,000.50	$ 148,454.63	$ 145,253.84	$ 147,038.43	$ 146,818.72	$ 144,735.01	$ 142,107.63
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 100,580.00	$ 110,560.00	$ 119,290.00	$ 127,370.00	$ 135,580.00	$ 143,590.00	$ 149,720.00	$ 154,780.00	$ 160,330.00	$ 165,720.00
FUEL - RIDER A	$ 217,326.00	$ 234,210.00	$ 240,042.00	$ 253,278.00	$ 268,632.00	$ 280,434.00	$ 309,078.00	$ 343,068.00	$ 363,450.00	$ 386,856.00
FUEL SECURITIZATION	$ 16,578.00	$ 14,754.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,392.00	$ 1,380.00	$ 1,368.00	$ 1,296.00	$ 1,296.00	$ 1,332.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 1,680.70	$ 1,722.37	$ 1,765.29	$ 1,809.50	$ 1,855.04	$ 1,901.94	$ 1,950.25	$ 2,000.01	$ 2,051.27	$ 2,104.06
Generation Infrastructure										
GENERATION RIDERS [2]	$ 18,660.00	$ 18,670.00	$ 17,980.00	$ 17,830.00	$ 18,350.00	$ 17,750.00	$ 17,760.00	$ 17,620.00	$ 18,230.00	$ 18,720.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 16,330.00	$ 19,600.00	$ 21,700.00	$ 22,510.00	$ 22,630.00	$ 22,510.00	$ 22,250.00	$ 21,620.00	$ 20,990.00	$ 20,160.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 6,270.00	$ 7,770.00	$ 7,600.00	$ 7,430.00	$ 7,220.00	$ 6,630.00	$ 6,510.00	$ 6,380.00	$ 6,260.00	$ 6,130.00
Distribution Infrastructure [3]										
DISTRIBUTION RIDERS	$ 2,460.00	$ 2,530.00	$ 2,460.00	$ 2,380.00	$ 2,320.00	$ 2,240.00	$ 2,160.00	$ 2,090.00	$ 2,020.00	$ 1,950.00
A5 Environmental										
RIDER E	$ 2,020.00	$ 2,120.00	$ 2,040.00	$ 1,610.00	$ 1,510.00	$ 1,430.00	$ 1,380.00	$ 1,320.00	$ 1,250.00	$ 1,200.00
RIDER CCR	$ 14,358.00	$ 14,358.00	$ 14,328.00	$ 14,328.00	$ 14,358.00	$ 23,358.00	$ 15,804.00	$ 15,906.00	$ 2,190.00	$ 786.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 18,380.00	$ 27,520.00	$ 38,450.00	$ 50,960.00	$ 75,950.00	$ 86,780.00	$ 92,860.00	$ 93,320.00	$ 93,120.00	$ 92,080.00
RPS Program-Related Resources										
RIDER RPS [4]	$ 51,372.00	$ 56,766.00	$ 63,618.00	$ 68,550.00	$ 69,930.00	$ 71,820.00	$ 76,692.00	$ 79,662.00	$ 89,508.00	$ 98,802.00
RIDER CE [5]	$ 44,274.00	$ 60,466.00	$ 74,738.00	$ 86,408.00	$ 98,244.00	$ 110,470.00	$ 122,660.00	$ 134,344.00	$ 146,078.00	$ 155,286.00
RIDER CE - FUEL BENEFIT	$ (17,160.00)	$ (24,642.00)	$ (31,302.00)	$ (36,876.00)	$ (44,676.00)	$ (51,048.00)	$ (57,186.00)	$ (64,584.00)	$ (74,010.00)	$ (85,524.00)
RIDER CE - REC PROXY VALUE	$ (9,720.00)	$ (10,530.00)	$ (15,474.00)	$ (19,296.00)	$ (21,624.00)	$ (22,512.00)	$ (22,800.00)	$ (22,404.00)	$ (22,764.00)	$ (22,614.00)
RIDER CE - CAPACITY OFFSET	$ (2,570.00)	$ (2,800.00)	$ (3,100.00)	$ (3,480.00)	$ (4,090.00)	$ (4,930.00)	$ (5,680.00)	$ (6,470.00)	$ (7,230.00)	$ (7,950.00)
TOTAL RIDER CE	**$ 14,824.00**	**$ 22,494.00**	**$ 24,862.00**	**$ 26,756.00**	**$ 27,854.00**	**$ 31,980.00**	**$ 36,994.00**	**$ 40,886.00**	**$ 42,074.00**	**$ 39,198.00**
RIDER OSW [6]	$ 29,250.00	$ 26,930.00	$ 28,460.00	$ 30,460.00	$ 30,860.00	$ 36,320.00	$ 51,390.00	$ 79,080.00	$ 89,360.00	$ 100,730.00
RIDER OSW - FUEL BENEFIT	$ (32,256.00)	$ (31,986.00)	$ (31,254.00)	$ (31,212.00)	$ (31,890.00)	$ (32,652.00)	$ (34,704.00)	$ (45,636.00)	$ (47,940.00)	$ (50,442.00)
RIDER OSW - REC PROXY VALUE	$ (19,800.00)	$ (19,734.00)	$ (19,038.00)	$ (18,120.00)	$ (16,698.00)	$ (15,120.00)	$ (13,476.00)	$ (12,714.00)	$ (14,958.00)	$ (13,590.00)
RIDER OSW - CAPACITY OFFSET	$ (4,450.00)	$ (3,890.00)	$ (3,870.00)	$ (4,030.00)	$ (4,290.00)	$ (4,290.00)	$ (4,180.00)	$ (5,170.00)	$ (5,940.00)	$ (6,170.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (27,256.00)**	**$ (28,680.00)**	**$ (25,702.00)**	**$ (22,902.00)**	**$ (22,018.00)**	**$ (15,742.00)**	**$ (970.00)**	**$ 15,560.00**	**$ 20,522.00**	**$ 30,528.00**
NUCLEAR SMALL MODULAR REACTORS [7]	$ 140.00	$ -	$ -	$ -	$ -	$ 500.00	$ 1,470.00	$ 3,640.00	$ 7,600.00	$ 13,300.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 39,080.00**	**$ 50,580.00**	**$ 62,778.00**	**$ 72,404.00**	**$ 75,766.00**	**$ 88,558.00**	**$ 114,186.00**	**$ 139,748.00**	**$ 159,704.00**	**$ 181,828.00**
TOTAL	**$ 603,660.39**	**$ 654,400.69**	**$ 681,362.45**	**$ 724,206.00**	**$ 773,921.67**	**$ 821,767.78**	**$ 882,040.68**	**$ 946,014.73**	**$ 975,674.28**	**$ 1,020,985.69**
CAGR (2019 BASE)							5.9%			
CAGR (MAY 2020 BASE)							6.8%			

[1] Publicly available, annualized tariff rates consistent with the r
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, a
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all a
[4] Includes the cost of REC purchases, deficiency payments, and
[5] Includes specific Company-owned projects and PPAs proposec
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, tl

Appendix 4A
Virginia Bill Analysis

Rate Outlook 2019 to 2045
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - LEAST COST VCEA COMPLIANT WITHOUT EPA, DIRECTED METHODOLOGY

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2039 DEC 2039	2040 DEC 2040	2041 DEC 2041	2042 DEC 2042	2043 DEC 2043	2044 DEC 2044	2045 DEC 2045
DISTRIBUTION & GENERATION (BASE) [1]	$ 147,836.89	$ 148,523.15	$ 154,746.73	$ 156,977.98	$ 160,277.26	$ 162,524.92	$ 165,801.33
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 170,950.00	$ 176,030.00	$ 180,950.00	$ 185,720.00	$ 190,330.00	$ 194,780.00	$ 108,160.00
FUEL - RIDER A	$ 425,892.00	$ 462,090.00	$ 521,916.00	$ 580,284.00	$ 638,922.00	$ 712,020.00	$ 773,838.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00	$ 1,344.00
RIDER PIPP - UNIVERSAL SERVICE FEE	$ 2,014.19	$ 2,063.88	$ 2,115.06	$ 2,167.78	$ 2,222.08	$ 2,278.00	$ 2,335.61
Generation Infrastructure							
GENERATION RIDERS [2]	$ 17,800.00	$ 18,560.00	$ 18,240.00	$ 17,680.00	$ 16,950.00	$ 14,930.00	$ 15,430.00
NUCLEAR SUBSEQUENT LICENSE RENEWAL - RIDER SNA	$ 19,350.00	$ 18,540.00	$ 17,750.00	$ 16,990.00	$ 16,270.00	$ 15,570.00	$ 14,920.00
CHESTERFIELD ENERGY RELIABILITY CENTER - RIDER CERC	$ 6,000.00	$ 5,870.00	$ 5,740.00	$ 5,610.00	$ 5,480.00	$ 5,380.00	$ 5,330.00
Distribution Infrastructure [3]							
DISTRIBUTION RIDERS	$ 1,870.00	$ 1,790.00	$ 1,680.00	$ 1,580.00	$ 1,450.00	$ 1,360.00	$ 1,280.00
A5 Environmental							
RIDER E	$ 1,120.00	$ 1,070.00	$ 1,010.00	$ 950.00	$ 1,470.00	$ 410.00	$ 380.00
RIDER CCR	$ 1,986.00	$ 870.00	$ 84.00	$ -	$ -	$ -	$ -
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources							
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERIC GAS	$ 89,620.00	$ 87,270.00	$ 84,960.00	$ 82,670.00	$ 80,410.00	$ 78,170.00	$ 75,920.00
RPS Program-Related Resources							
RIDER RPS [4]	$ 105,810.00	$ 89,976.00	$ 105,564.00	$ 121,938.00	$ 131,130.00	$ 141,504.00	$ 157,068.00
RIDER CE [5]	$ 163,160.00	$ 171,904.00	$ 179,780.00	$ 185,774.00	$ 194,288.00	$ 202,212.00	$ 210,926.00
RIDER CE - FUEL BENEFIT	$ (98,370.00)	$ (108,594.00)	$ (130,998.00)	$ (159,720.00)	$ (185,502.00)	$ (221,580.00)	$ (248,028.00)
RIDER CE - REC PROXY VALUE	$ (22,032.00)	$ (21,048.00)	$ (19,434.00)	$ (19,410.00)	$ (19,206.00)	$ (18,786.00)	$ (18,102.00)
RIDER CE - CAPACITY OFFSET	$ (8,580.00)	$ (8,860.00)	$ (8,710.00)	$ (8,550.00)	$ (7,960.00)	$ (7,720.00)	$ (7,260.00)
TOTAL RIDER CE	**$ 34,178.00**	**$ 33,402.00**	**$ 20,638.00**	**$ (1,906.00)**	**$ (18,380.00)**	**$ (45,874.00)**	**$ (62,464.00)**
RIDER OSW [6]	$ 106,500.00	$ 125,970.00	$ 120,460.00	$ 116,630.00	$ 113,340.00	$ 110,530.00	$ 109,600.00
RIDER OSW - FUEL BENEFIT	$ (59,898.00)	$ (101,514.00)	$ (113,226.00)	$ (126,594.00)	$ (142,284.00)	$ (159,552.00)	$ (174,720.00)
RIDER OSW - REC PROXY VALUE	$ (12,186.00)	$ (11,634.00)	$ (17,358.00)	$ (16,380.00)	$ (15,372.00)	$ (14,358.00)	$ (13,260.00)
RIDER OSW - CAPACITY OFFSET	$ (6,390.00)	$ (9,540.00)	$ (11,810.00)	$ (12,030.00)	$ (12,260.00)	$ (12,380.00)	$ (12,560.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 28,026.00**	**$ 3,282.00**	**$ (21,934.00)**	**$ (38,374.00)**	**$ (56,576.00)**	**$ (75,760.00)**	**$ (90,940.00)**
NUCLEAR SMALL MODULAR REACTORS [7]	$ 20,570.00	$ 28,430.00	$ 36,480.00	$ 46,420.00	$ 51,000.00	$ 53,090.00	$ 50,640.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 188,584.00**	**$ 155,090.00**	**$ 140,748.00**	**$ 128,078.00**	**$ 107,174.00**	**$ 72,960.00**	**$ 54,304.00**
TOTAL	**$ 1,074,367.08**	**$ 1,079,111.03**	**$ 1,131,283.79**	**$ 1,180,051.76**	**$ 1,222,299.34**	**$ 1,261,726.92**	**$ 1,219,042.94**
CAGR (2019 BASE)	5.8%						4.9%
CAGR (MAY 2020 BASE)	6.5%						5.4%

[1] Publicly available, annualized tariff rates consistent with the r
[2] Consolidated Generation Riders B, BW, GV, US-2, US-3, US-4, a
[3] Consolidated Distribution Riders GT, U, and RBB. Includes all a
[4] Includes the cost of REC purchases, deficiency payments, and
[5] Includes specific Company-owned projects and PPAs proposec
[6] No assumptions modeled for exemptions to Riders OSW.
[7] While nuclear small modular reactors do not generate RECs, tl

Appendix 4B: North Carolina Bill Analysis

Filed in North Carolina only.

The Company calculated projected residential bills for each Primary Portfolio in accordance with the Final NCUC Order in the 2024 IRP. Pursuant to that Order, the Company also provided a breakout of the Investment Tax Credits and Production Tax Credits within the 2025 NC IRP Consolidated Bill Analysis Workpapers.

Appendix 5A: Environmental Regulations

Historically, coal-fired, biomass and natural gas-fired generation have played an important role in maintaining reliability. Natural gas fired units, particularly simple cycle CTs can be dispatched quickly in times of high demand, such as cold winter weather. The coal and biomass units maintain a robust fuel storage supply and are crucial for reliability in the event that natural gas is unavailable in a particular region or curtailed during peak winter weather events. However, recent state and federal policy changes may affect the dispatch and continued operations of traditional fossil generation.

At the state level, the VCEA mandates the retirement of carbon-emitting units by 2045 unless retirement of the unit would threaten the reliability or security of electric service to customers. From January 1, 2021, through December 31, 2023, Virginia was a member of the Regional Greenhouse Gas Initiative ("RGGI") and the Company was required to purchase allowances to cover carbon dioxide ("CO_2") emissions from its regulated emissions sources. However, the RGGI regulation was repealed on August 1, 2023, and Virginia exited RGGI effective December 31, 2023. Accordingly, there are no overarching Virginia carbon regulations applicable to the Company's generation fleet.

At the federal level, a series of recent U.S. Environmental Protection Agency ("EPA") regulations applicable to existing coal-fired steam generating units and gas and oil-fired combustion turbines may constrain existing generation within the Company's fleet and the PJM footprint as a whole or retiring units prematurely. Options to maintain existing generation units while complying with the rules would likely require significant capital investment and may require additional infrastructure (*i.e.*, gas pipelines or carbon storage). Certain technologies that could be used to comply, like carbon capture sequestration ("CCS") or hydrogen co-firing are still under development, are only viable in certain geographical/geological locations and not yet commercially available. While other legislation, like the Inflation Reduction Act, is incentivizing the development of new technologies, the successful commercialization of these technologies is not guaranteed, especially in the near future.

A summary of the federal regulations and their impacts is below. Some of these rules are being challenged by various groups and may change in the future. Additional details regarding existing and pending environmental regulations are provided in Appendix 5A Environmental Regulations Table 1 from the 2024 IRP.

Federal Carbon Regulations

The past decade has seen attempts at carbon regulation at the federal level. The Clean Power Plan, announced in 2015 by President Obama, sought to set limits on carbon emissions from power plants. In 2018, President Trump announced the Affordable Clean Energy Rule ("ACE Rule"), which repealed and replaced the Clean Power Plan with a rule that sought to set heat rate efficiency improvements and improved operating and maintenance practices. Both efforts, which were adopted by the EPA under Section 111(d) of the Clean Air Act ("Section 111(d)"), saw significant legal challenges.

On January 19, 2021, the D.C. Circuit Court vacated the ACE Rule. On June 30, 2022, the U.S. Supreme Court issued a decision in *West Virginia v. EPA* that limits the scope of the EPA's authority to control greenhouse gas emissions from existing power plants under Section 111(d). This decision impacts how greenhouse gas emissions can be regulated at existing power plants by the EPA in future rulemakings, absent action from Congress.

Clean Air Act Section 111(d) ("Section 111(d)")

The final Section 111(d) rule was published in the Federal Register on May 9, 2024, and sets forth emission guidelines for existing coal, oil and gas fired steam generating units. Under Section 111(d), coal units have the following options to comply: (1) retire by January 1, 2032; (2) transition to 40% natural gas by 2030; or (3) install carbon capture and sequestration technology with a 90% capture rate by 2032. Units that elect natural gas co-firing but do not install CCS, must retire by January 1, 2039. As an alternative, units can also convert to 100% natural gas and operate as a natural gas fired steam generating unit but must cease using coal entirely by January 1, 2030. Natural gas fired steam generating units or units that install CCS do not have a mandated retirement date. States also have the flexibility to consider a range of approaches to achieve the emission reductions identified through BSER, through submittal of a state plan.

Clean Air Act Section 111(b) ("Section 111(b)")

The EPA revised the New Source Performance Standards ("NSPS") under Section 111(b) for greenhouse gas emissions from new and reconstructed gas and oil-fired stationary combustion turbines as well as coal, gas, and oil-fired steam generating units that undertake a large modification. The rule was published in the Federal Register on May 9, 2024. Section 111(b) sets different standards for CO2 emissions based on a unit's capacity factor. New or modified gas-fired combustion turbines that operate at or less than 40% capacity factor will have a CO2 emission standard upon startup but do not require CCS. Units operating above 40% capacity factor have an accompanying CO2 emission standard upon startup and are required to install CCS technology with a 90% capture rate by 2032. Coal units that undertake a large modification would need to employ a unit-specific CO2 emission standard. Other technologies such as hydrogen fuel blending also can be used to meet the new emission standards or in lieu of CCS to meet EPA's Best System Emission Reduction, so long as those technologies are equivalent in stringencies.

EPA Publishes Proposed Rule to Rescind GHG Emission Standards for Fossil Fuel-Fired Electric Generating Units

EPA published a proposed rule alternatives to the Section 111(d) and (b) regulations on June 17, 2025. The primary proposal is a full repeal of GHG emission standards for existing and new sources, finding that GHG emissions from power plants "do not contribute significantly to dangerous air pollution" under Section 111 of the Clean Air Act, and therefore precludes EPA from regulating GHG emissions from these plants. In addition to its primary proposal to repeal all GHG emission standards for the power sector, EPA has included an alternative proposal to repeal specific portions of the regulations based on revised BSER determinations for existing coal-fired steam generating units and new base load combustion turbines. EPA is proposing to determine that CCS is not BSER for these units and therefore proposes to eliminate all carbon capture sequestration-based standards from the 2024 rules.

Mercury and Air Toxics Standards Rule ("MATS Rule")

In May 2024, EPA released a final rule to tighten certain aspects of the Mercury and Air Toxics Standards Risk and Technology Review for coal units. Specifically, the rule reduced the filterable particulate matter ("PM") limit from 0.030 pounds per metric million British thermal unit ("lb/MMBtu") to 0.010 lb/MMBtu for coal units. Additionally, use of continuous emissions monitoring systems is required to demonstrate compliance with the PM limit. Compliance is required within three years of the final rule (July 8, 2027) with an option to request a one-year extension from the local permitting authority. Mt. Storm received a two-year extension to comply with the revised MATs rule (July 8, 2029) under a Presidential Proclamation pursuant to Clean Air Act Section 112.

On June 17, 2025, EPA published in the Federal Register its proposal to repeal the majority of the 2024 final MATs rule. The Proposed Rule would repeal the revised PM emission standard, the compliance demonstration requirements, and the revised mercury (Hg) emission standard for lignite-fired EGUs under the 2024 Rule, while retaining the revised definition of "startup" for purposed of MATs compliance.

Ozone National Ambient Air Quality Standards ("NAAQS")

The NAAQS govern ground-level ozone forming pollutants, including nitrogen oxide ("NOx") emissions. The Clean Air Act requires the EPA to review and revise the NAAQS every five years, if necessary. The final Federal Implementation Plan ("FIP") addressing interstate transport for the 2015 NAAQS became effective in August 2023. Virginia and West Virginia were included in the FIP. The revisions to the standards and proposed FIP impose tighter emission caps on NOx emissions during the ozone season, as well as increased costs for obtaining NOx allowances, which are needed to comply with this rule. Coal-fired electric generating units (excluding circulating fluidized bed boilers) are subject to daily emission rate limits during the ozone season and would have to surrender additional allowances if these limits were exceeded. On June 27, 2024, the U.S. Supreme Court, issued an order to stay the EPA's FIP. The stay, as implemented by EPA, will preserve the status quo prior to the finalization of the of the FIP and impacted states will revert to the previous iteration of this rule ("Revised CSAPR Update rule").

Effluent Limitation Guidelines ("ELG")

In May 2024, the EPA released a final rule revising the 2015 and 2020 Effluent Limitations Guidelines, establishing more stringent standards for wastewater discharges for the steam electric power generating category, generally affecting BATW, FGD wastewater, and combustion residual leachate. Individual facilities' compliance dates will vary based on circumstances and the permitting authority's determination. Compliance dates may be incorporated into station discharge permits as late as 2029, except in certain circumstances when a station will be retired by 2034. The 2024 ELG rule newly regulates combustion residual leachate discharges from a landfill at an active coal station imposing a zero liquid discharge standard by no later than December 31, 2029.

On September 29, 2025, EPA released a Proposed Rule and a Direct Final Rule to revise various deadlines and other provisions of the 2024 ELG Rule. The proposal includes extending the zero-discharge compliance deadlines by five years for FGD wastewater, BATW, and CRL. Additionally, a Direct Final Rule was issued to extend the deadline for existing coal-fired steam power plants to submit a Notice of Planned Participation (NOPP) for the permanent cessation of coal combustion subcategory promulgated under the 2024 Supplemental Steam Reconsideration Rule extending the deadline to submit the NOPP from December 31, 2025, to December 31, 2031.

Appendix 5B: Cost Assumptions

This appendix includes a discussion of the following topics:

- Gas Transportation Cost Assumptions;
- Construction Cost Assumptions; and
- Commodity Price and Cost Assumptions.

I. Gas Transportation Cost Assumptions

Natural gas is largely delivered on a just-in-time basis. Vulnerabilities in natural gas supply and transportation must be sufficiently evaluated from a planning and reliability perspective. Mitigating strategies such as storage, peaking services, on-site fuel capability, firm natural gas supply purchases, firm pipeline transportation capacity, alternate pipelines, dual-fuel capability, access to multiple natural gas supply basins, and overall fuel diversity all help to alleviate this risk.

There are two main types of pipeline transportation service contracts: firm and interruptible. Natural gas delivered using a firm pipeline transportation service contract is available to the customer during the contract term and is not subject to a prior transportation service claim from another customer. The Company regularly uses both primary and secondary receipt and delivery flexibility inherent in its pipeline firm transportation contracts to reliably deliver fuel to its gas-fired generation fleet. While a pipeline force majeure event can interrupt primary, firm transportation service, pipeline constraints and restrictions can limit some or all secondary receipt/delivery flexibility, beyond primary firm contractual rights. Additionally, for firm natural gas supply to be delivered reliably, sufficient supply must be scheduled in accordance with Federal Energy Regulatory Commission ("FERC")-approved pipeline nomination cycles, flow rules, and then-effective pipeline constraints and restrictions.

For a firm pipeline transportation and/or storage service contract, the customer pays a monthly capacity reservation charge that recovers its share of FERC-approved pipeline fixed costs supporting the firm service. Interruptible pipeline transportation service contracts provide transportation subject to the contractual rights of firm customers and other pipeline constraints and restrictions. The Company predominantly uses firm pipeline transportation and firm storage services to fuel its natural gas-fired generation fleet but can also use interruptible pipeline transportation service depending on availability and PJM-directed need for gas-fired generation.

The Company included natural gas pipeline transportation and storage costs in its modeling. The Company predominantly uses firm pipeline transportation and storage to fuel its combined-cycle facilities. Additionally, the Company can utilize a firm pipeline transportation service not otherwise needed for its combined-cycle facilities, to fuel its CTs. When available, the Company can utilize interruptible pipeline transportation service for CTs because these peaking resources typically operate with less than 20% capacity factors and are typically equipped with on-site backup fuel. For modeling purposes, the Company typically assumes gas availability in the spring, summer, and fall, with more limited availability in winter when oil-only operation is more common.

The Company continually evaluates its generation fueling portfolio (including firm and interruptible natural gas pipeline transportation services) with fuel deliverability, flexibility, and affordability in mind. Specifically for natural gas, given that the physical location of the Company's gas-fired generation fleet is in a fully subscribed pipeline corridor, pipeline constraints and associated restrictions to secondary flexibility rights are commonplace. Therefore, in the interest of generation fuel reliability, the Company requests and reviews proposals (covering various terms) for incremental firm transportation, pipeline storage, peaking services, and onsite fueling (oil or LNG). For example, given the current construction and regulatory uncertainties associated with new natural gas pipeline builds, natural gas peaking services, or on-site LNG can be effective options to place specified amounts of natural gas fuel at specified locations for peak periods.

The Company employs a comprehensive approach to fuel commodity procurement as a part of its risk management strategy. Key priorities in fuel procurement include cost prudency, generation fuel diversity, security of commodity supply, and a balanced approach to hedging.

II. Construction Costs Assumptions

Assumptions in the 2025 IRP Update are based on the Company's extensive internal construction expertise and best available information from external resources, where appropriate. The Company has leveraged these resources to manage construction costs for new resources despite recent volatility in equipment pricing, supply chains, and environmental regulations, and the Company remains committed to its focus on prudent construction cost management for ongoing projects in order to deliver them on-time and on-budget for customers and will update these assumptions in future filings, as appropriate.

For this 2025 IRP Update, the projected solar and energy storage capital costs are based on the market in Dominion Energy's service territory using cost data from Company-developed projects through 2026, adjusting for escalation, indexation, and project-specific changes, where required.

Additionally, with regard to small modular reactors ("SMR"), the Company analyzed capital costs estimates provided by technology vendors and developed a cost estimate based on a generic SMR site in Virginia.

For the Solar PPA cost assumptions, a market index price was created using the weighted average first year price from conforming PPA bids in the Company's request for proposals ("RFP") for utility-scale solar, onshore wind, and energy storage resources. The market index price was then escalated by approximately 30% to account for the elimination of tax credits for solar site developments and then adjusted based on the NREL moderate scenario.

III. ICF Commodity Price and Cost Assumptions

Virginia REC Market

The Virginia Clean Economy Act ("VCEA") instituted a mandatory renewable portfolio standard ("RPS") Program in Virginia under which Dominion Energy must meet annual requirements for the sale of renewable energy based on a percentage of non-nuclear electric energy sold to retail customers in the Company's service territory, starting at 14% for the 2021 compliance year and increasing to 100% in compliance year 2045 and beyond. In years 2021 to 2024, the Company was able to use renewable energy certificates ("RECs") for RPS Program compliance originating from renewable energy facilities located within the PJM region. Beginning in 2025, 75% of the RECs used by the Company for RPS Program compliance must come from resources located in Virginia, with additional limitations on the type of facilities that qualify for compliance. Additionally, of the required percentage in each compliance year, 1% of the RECs must be from certain distributed energy resources ("DERs") located in Virginia with a nameplate capacity of 1 MW or less.

The majority of Virginia RPS-eligible sources qualify for RPS compliance in multiple states. A large and growing number of corporate buyers also procure and retire RECs to either sell in the market or meet their company corporate specific sustainability goals. Therefore, the Company competes with corporate buyers for the purchase of qualifying RECs. The ability of other entities to bank eligible RECs in other jurisdictions further complicates REC availability analysis.

We estimate that the Company's need for RECs will grow from approximately 14 million in 2025 to approximately 49 million in 2035. These numbers incorporate adjustments of the REC forecast for a growing volume of accelerated renewable energy buyer ("ARB") customers who meet their REC needs with contracts within PJM.

If the REC market is undersupplied, the market price of RECs is likely to get close to the VCEA-imposed deficiency payment. The 2025 IRP Update includes a forecast of Virginia REC price, which are projected to be equal to the PJM REC market prices. Notably, REC prices within existing PJM REC markets have risen since the enactment of the VCEA, in part because of the increased demand for RECs to comply with the mandatory Virginia RPS Program.

Capacity Price Forecasting Methodology

In most wholesale electricity markets, electric power generators are paid for providing:

- Energy: the actual electricity consumed by customers;
- Capacity: standing ready to provide a specified amount of electric energy; and,
- Ancillary services: a variety of operations needed to maintain grid stability and security, including frequency control, spinning reserves, and operating reserves.

The purpose of a mandatory capacity market is to encourage new investments where they are most needed on the grid. PJM's capacity market (*i.e.*, the RPM), ensures long-term grid reliability by procuring the appropriate amount of supply- and demand-side resources needed to meet predicted peak demand in the future. In a capacity market, utilities or other electricity suppliers are required to purchase adequate resources to meet their customers' demand plus a reserve amount. Suppliers offer supply- or demand-side resources into the capacity market at a price. To the extent the supply offer clears the market, then those capacity resources are obligated to supply energy (or reduce energy in the case of demand-side resources) when dispatched or pay penalty fees.

The RPM is designed to provide financial incentives to attract and maintain sufficient capacity to meet the load demands anticipated by PJM; in concept, revenues from energy and ancillary services plus capacity payments should equal the amount necessary to attract new entry. Parallel to the actual market construct, forecasting of long-term capacity prices is based on estimating the amount of capacity revenue a generation resource requires, in addition to revenue from energy and ancillary services. The capacity revenue forecast represents the amount by which a resource's cost exceeds its forecasted wholesale electricity market revenues. The basic concept utilized in forecasting is that in order to maintain appropriate reserve levels to assure reliable electric service, generating resources will require sufficient revenue to cover expenses and, when necessary, support the required new investment. When wholesale market energy and ancillary services revenue is not sufficient, then capacity revenues are required to fill this gap.

When forecasting capacity prices over long periods, it is reasonable to assume markets will move toward equilibrium and will provide sufficient revenue to support existing resources and incent investment in new resources that require equity returns on the capital expended for development and construction of the new resource. In markets with excess capacity, existing resources generally set the capacity price. These resources require revenue to cover only operating expenses and do not include equity returns or significant going forward capital expenditures. Because of this, the capacity price tends to be lower in markets with excess capacity. However, over the long term, the market is expected to move to an equilibrium status where sufficient revenues are provided, which assures adequate resource capacity and encourages market efficiency. Note that while long-term forecasts tend toward an equilibrium pricing, it is expected that actual markets will continue to follow an up-and-down cycle that moves around equilibrium levels. Long-term forecasts for capacity focus on the equilibrium level pricing rather than attempting to estimate the cyclical movement.

Commodity Price Assumptions

The Company utilizes a single source—ICF—to provide multiple scenarios for the commodity price forecasts to ensure consistency in methodologies and assumptions. The key assumptions on market structure and the use of an integrated, internally consistent fundamentals-based modeling methodology remain consistent with those utilized by ICF in prior years' commodity forecasts.

The Company performed the analyses in this 2025 IRP Update using energy and commodity price forecasts provided by ICF in all periods except the first 36 months of the 15-year Planning Period. The forecasts used for natural gas, coal, power, emissions (*e.g.*, sulfur oxide ("SOx"), nitrogen oxide ("NOx"), RGGI), and REC prices rely on forward market prices as of May 28, 2025, for the first 18 months of the Planning Period and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively. The forecast used for capacity prices are provided by ICF for all years forecasted within this 2025 IRP Update. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM base residual auction through the 2026/2027 delivery year, then transitioning to the ICF capacity forecast.

In the 2025 IRP Update, the Company utilized six commodity forecasts:

- Base Case with EPA 111 Rules
- Sensitivity with No EPA 111 Rules
- Sensitivity with High Fuel Price
- Sensitivity with Low Fuel Price
- Sensitivity with VCEA Retirements included
- Sensitivity with Virginia included in RGGI

The Company used the Base Case commodity forecast for the Portfolios. The remaining five commodity forecasts were used to run sensitivities.

As with all forecasts, there remain multiple possible outcomes for future prices that fall outside of the commodity prices developed for this 2025 IRP Update. History has shown that unforeseen events and events not contemplated five or ten years before their occurrence can result in significant changes in market fundamentals. The effects of unforeseen events should be considered when evaluating the viability of long-term planning objectives. The commodity price forecasts analyzed in the 2025 IRP Update present reasonably likely outcomes given the current understanding of market fundamentals, but do not present all possible outcomes.

Environmental Commodity Price Forecast

The Base Case commodity forecast (*i.e.*, the environmental commodity price forecast) was developed for the Company to address a future market environment where impacts of the supply chain and commodity price dislocations of the last 24 months are incorporated into projections, natural gas continues to be a dominant marginal source of generation in PJM over the time horizon, tax credits available to renewable and clean technologies from the 2025 Federal Tax Bill are incorporated, and enactment of various RPS policies occur.

Table 1 below provides a comparison of the four commodity price forecasts in this 2025 IRP Update with the base commodity forecast used in the 2024 IRP.

Table 1: Fuel, Power, and REC Price Commodity Forecast Comparison

(Nominal $)	2024-2039	2025-2045					
Fuel Price	2024 Base Case (w/ EPA Rules)	Base Case (W-EPA and W-Federal Tax Bill)	Case (No EPA & W-Federal Tax Bill)	Sensitivity (VCEA Retirement)	Sensitivity (High Fuel Price)	Sensitivity (Low Fuel Price)	Sensitivity (VA RGGI Case)
Henry Hub Natural Gas ($/MMbtu)	4.7	5.9	5.8	5.9	9.3	3.6	5.9
Zone 5 Delivered Natural Gas ($/MMbtu)	4.9	6.0	5.8	6.0	9.4	3.6	5.9
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	81.9	77.8	78.3	77.8	77.9	77.4	77.8
No. 2 Oil ($/MMbtu)	20.3	22.4	22.4	22.4	25.7	20.0	22.4
Electric and REC Prices							
PJM-DOM On-Peak ($/MWh)	37.8	83.5	71.7	83.4	108.2	64.3	90.0
PJM-DOM Off-Peak ($/MWh)	38.9	83.1	72.0	83.0	110.8	63.0	94.6
PJM Tier 1 REC Prices ($/MWh)	35.6	16.4	21.6	15.9	10.9	26.8	15.0
VA REC Prices ($/MWh)	36.0	16.4	21.6	15.9	10.9	26.8	15.0
Dom Zone Capacity Prices ($/kW-yr)	178.0	177.3	179.3	174.4	160.3	184.5	168.2

Note: (1) Reflects ICF forecast and market blend.

VCEA Retirement Price Sensitivity

The VCEA Retirement commodity forecasts utilizes assumptions that align with VCEA requirements to retire all carbon emitting generating stations by December 31, 2045, for Dominion Energy and Appalachian Power Company. Units are assumed to retire over the period from 2041 through 2045.

A change in retirement assumptions generally leaves gas, oil, and coal prices unaffected; however, local demand shifts do result in slight shifts in delivery costs. The REC prices see a decrease due to the higher energy revenues available to renewables in the outer years of the planning forecast. Finally, while new generating capacity is needed to replace existing generators that must retire in this scenario, the energy revenues for existing resources, new non-hydrogen resources in Virginia including new nuclear builds, and new gas resources across PJM also increase, reducing the make whole payment required to maintain sufficient capacity. As a result, the capacity prices decrease in this scenario.

High / Low Fuel Price Sensitivity

The High and Low Fuel Price commodity forecasts utilize high and low natural gas supply scenarios from the EIA to create high and low cases of natural gas fuel prices, as natural gas continues to be a dominant marginal source of generation in PJM over the time horizon in the Base Cases.

A change in natural gas prices affects energy prices directly. That is, as natural gas fuel prices increase, energy prices increase. The energy price affects the revenue stream available to renewable energy generators, which in turn results in a change in REC price. In other words, as energy prices increase due to higher fuel prices, REC prices generally decrease as a result of increased renewable build. Similarly, the capacity price is also directly influenced by the marginal sources of energy and is reflective of the net energy compensation requirements. In other words, as revenue available to renewable energy generators increases due to higher fuel prices, capacity prices decrease. Hence, the movement of natural gas prices will impact the resulting power market commodity prices directly and in a consistent manner across high and low scenarios.

VA RGGI Sensitivity

The VA in RGGI sensitivity commodity forecasts utilizes assumptions that Virginia joins the RGGI program beginning in 2026. RGGI —a cap-and-trade program covering power sector emissions in 10 Northeastern and Mid-Atlantic states—has experienced increased volatility in 2025. While the Federal Tax Bill does not directly impact RGGI, it has created uncertainty by signaling a federal shift away from climate coordination, which has somewhat shaken investor confidence in state-led initiatives. However, RGGI has also recently issued a program update which indicates continuing commitment to the program and tightens long-term goals. Due to timing of the RGGI July 2025 Third Program Review update, it was not included in the scenarios and is not modeled. In all scenarios, the RGGI modeling aligns with the 2017 model rule update and an assumed 30% decline in cap levels between 2030 and 2040.

A change in RGGI assumptions sees a slight decrease in gas prices as the addition of Virginia to the program leads to decreasing gas consumption in the region. Oil and coal prices see minimal impact as power sector consumption of oil remains limited, the RGGI states have low coal capacity, and Virginia is limited in its dispatch due to VCEA and EPA regulations. Dom Zone energy prices increase due to additional pressure on the fossil generation under the RGGI cap. Dispatch costs for all Virginia fossil generation have an added cost associated with the RGGI allowance price as well as the fuel and variable operating costs. This incremental cost increases the marginal energy price when fossil units are marginal. Capacity and REC prices generally decrease in the RGGI sensitivity as energy prices increase and necessary make-whole payments decline.

Appendix 5B-1: Least Cost VCEA Compliant Price Forecast (Nominal $)

	Fuel Price				Power and REC Prices			RTO Capacity Prices				Emission Prices			
													CSAPR		
Year	Henry Hub Natural Gas ($/MMBtu)	Zone 5 Delivered Natural Gas ($/MMBtu)	CAPP CSX: 12,500 1%S FOB ($/MMBtu)	No. 2 Oil ($/MMBtu)	PJM-DOM On-Peak ($/MWh)	PJM-DOM Off-Peak ($/MWh)	PJM Tier 1 REC Prices ($/MWh)	RTO ($/kW-yr)	RTO ($/MW-day)*	Dom Zone ($/kW-yr)	Dom Zone ($/MW-day)*	SO2 ($/Ton)	Ozone NOx ($/Ton)	Annual NOx ($/Ton)	Federal CO2 Price ($/Ton)
2025	3.76	3.78	79.21	14.94	65.59	43.18	25.75	98.52	269.92	162.15	444.26	1.25	787.50	2.50	0.00
2026	4.27	4.95	80.48	14.89	68.74	52.03	25.54	111.14	304.49	137.65	377.13	1.29	800.16	2.57	0.00
2027	4.08	4.40	78.95	16.92	66.93	51.51	28.90	108.54	297.37	120.15	329.18	2.07	1,056.96	2.87	0.00
2028	4.40	4.51	72.22	20.09	59.00	54.59	32.34	105.73	289.66	144.28	395.30	3.17	1,450.16	3.26	0.00
2029	4.67	4.58	68.17	21.00	56.01	57.68	31.21	110.05	301.50	160.05	438.48	3.36	2,528.20	3.36	0.00
2030	4.93	4.80	65.68	21.59	54.60	61.42	29.59	108.30	296.71	144.57	396.08	3.42	2,609.85	3.42	0.00
2031	5.15	5.10	66.84	22.02	59.58	67.35	26.00	116.25	318.49	127.68	349.80	3.49	2,278.84	3.49	0.00
2032	5.38	5.28	68.47	22.47	66.08	73.40	22.26	122.59	335.87	122.59	335.87	3.56	1,946.21	3.56	0.00
2033	5.50	5.46	70.12	22.37	72.27	73.22	18.37	130.20	356.73	130.20	356.73	2.42	1,586.50	2.42	0.00
2034	5.61	5.64	71.79	22.26	74.48	77.00	14.30	142.46	390.31	142.46	390.31	2.47	1,223.31	2.47	0.00
2035	5.73	5.78	73.48	22.12	76.23	81.74	10.05	154.11	422.23	154.11	422.23	2.52	932.71	2.52	0.00
2036	5.94	6.00	75.19	22.55	81.08	82.34	9.65	166.97	457.45	166.97	457.45	2.57	385.58	2.57	0.00
2037	6.15	6.24	76.94	22.99	87.17	82.47	9.25	180.60	494.80	180.60	494.80	2.62	131.07	2.62	0.00
2038	6.38	6.45	78.76	23.45	87.05	88.44	8.82	194.29	532.30	194.29	532.30	2.67	2.67	2.67	0.00
2039	6.61	6.68	80.76	23.92	90.01	92.17	8.39	208.24	570.53	208.24	570.53	2.73	2.73	2.73	0.00
2040	6.86	6.89	82.73	24.41	91.68	97.45	7.92	222.77	610.34	222.77	610.34	2.79	2.79	2.79	0.00
2041	7.09	7.13	84.73	24.91	97.08	105.97	7.93	231.59	634.49	231.59	634.49	2.84	2.84	2.84	0.00
2042	7.32	7.35	86.78	25.42	109.62	108.95	7.94	236.18	647.06	236.18	647.06	2.90	2.90	2.90	0.00
2043	7.56	7.58	89.00	25.95	115.80	119.07	7.92	240.51	658.94	240.51	658.94	2.96	2.96	2.96	0.00
2044	7.82	7.78	91.20	26.49	125.83	126.82	7.92	243.18	666.24	243.18	666.24	3.02	3.02	3.02	0.00
2045	8.08	8.01	93.58	27.04	140.34	132.08	7.92	246.28	674.73	246.28	674.73	3.09	3.09	3.09	0.00

Note:
CSAPR SO2 and Nationwide SO2 prices are used as the SO2 Market Price
* RTO Capacity prices are restated in the units used by the PJM Capacity market

Appendix 5B-2: Commodity Price Forecast, Natural Gas

	Henry Hub Natural Gas ($/MMBtu)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	3.76	3.76	3.76
2026	4.27	4.27	4.26
2027	4.08	4.18	3.29
2028	4.40	4.81	2.46
2029	4.67	5.53	2.47
2030	4.93	6.73	2.64
2031	5.15	7.66	2.81
2032	5.38	8.64	3.18
2033	5.50	9.24	3.34
2034	5.61	9.69	3.44
2035	5.73	10.11	3.54
2036	5.94	10.70	3.62
2037	6.15	11.01	3.66
2038	6.38	11.11	3.72
2039	6.61	11.56	3.80

Appendix 5B-3: Commodity Price Forecast, Natural Gas

	Zone 5 Delivered Natural Gas ($/MMBtu)		
Year	**Least Cost VCEA Compliant Case**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2025	3.78	3.78	3.78
2026	4.95	4.95	4.94
2027	4.40	4.51	3.62
2028	4.51	4.93	2.57
2029	4.58	5.44	2.38
2030	4.80	6.60	2.51
2031	5.10	7.61	2.76
2032	5.28	8.54	3.07
2033	5.46	9.20	3.30
2034	5.64	9.72	3.47
2035	5.78	10.16	3.60
2036	6.00	10.76	3.68
2037	6.24	11.09	3.74
2038	6.45	11.18	3.79
2039	6.68	11.62	3.87

Appendix 5B-4: Commodity Price Forecast, Coal (FOB)

	CAPP CSX: 12,500 1%S FOB ($/ton)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	79.21	79.21	79.21
2026	80.48	80.48	80.48
2027	78.95	78.99	78.65
2028	72.22	72.32	71.51
2029	68.17	68.29	67.51
2030	65.68	65.79	65.09
2031	66.84	66.85	66.26
2032	68.47	68.47	67.89
2033	70.12	70.12	69.63
2034	71.79	71.79	71.30
2035	73.48	73.48	72.98
2036	75.19	75.19	74.68
2037	76.94	76.94	76.53
2038	78.76	78.76	78.35
2039	80.76	80.76	80.24

Appendix 5B-5: Commodity Price Forecast, Oil

	No. 2 Oil ($/MMBtu)		
Year	**Least Cost VCEA Compliant Case**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2025	14.94	14.94	14.94
2026	14.89	14.90	14.89
2027	16.92	17.58	16.29
2028	20.09	21.85	18.45
2029	21.00	23.14	19.09
2030	21.59	24.02	19.67
2031	22.02	24.61	19.87
2032	22.47	25.41	19.82
2033	22.37	25.39	19.77
2034	22.26	25.42	19.54
2035	22.12	25.43	19.47
2036	22.55	26.43	19.80
2037	22.99	27.21	20.16
2038	23.45	27.78	20.55
2039	23.92	28.36	20.87

Appendix 5B-6: Commodity Price Forecast, On-Peak Power Price

	PJM-DOM On-Peak ($/MWh)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	65.59	65.59	65.59
2026	68.74	68.75	68.66
2027	66.93	68.88	59.71
2028	59.00	66.31	42.35
2029	56.01	66.63	39.00
2030	54.60	68.04	38.12
2031	59.58	79.82	42.98
2032	66.08	94.10	48.67
2033	72.27	96.65	51.87
2034	74.48	99.43	55.39
2035	76.23	102.48	59.26
2036	81.08	106.13	60.81
2037	87.17	110.04	62.46
2038	87.05	114.26	64.24
2039	90.01	118.83	66.17

Appendix 5B-7: Commodity Price Forecast, Off-Peak Power Price

	PJM-DOM Off-Peak ($/MWh)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	43.18	43.18	43.18
2026	52.03	52.04	51.96
2027	51.51	51.96	44.29
2028	54.59	54.52	33.91
2029	57.68	56.78	32.19
2030	61.42	76.38	42.51
2031	67.35	89.42	47.96
2032	73.40	105.07	54.31
2033	73.22	106.93	57.02
2034	77.00	109.02	60.00
2035	81.74	111.35	63.27
2036	82.34	115.28	64.78
2037	82.47	119.56	66.42
2038	88.44	124.26	68.23
2039	92.17	129.41	70.21

Appendix 5B-8: Commodity Price Forecast, PJM Tier 1 RECs

	PJM Tier 1 REC Prices ($/MWh)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	25.75	25.75	25.75
2026	25.54	25.54	25.54
2027	28.90	28.90	28.90
2028	32.34	29.26	34.80
2029	31.21	24.62	36.46
2030	29.59	19.73	37.43
2031	26.00	16.63	35.30
2032	22.26	13.41	33.10
2033	18.37	10.05	30.77
2034	14.30	6.54	28.33
2035	10.05	2.89	25.79
2036	9.65	2.94	24.99
2037	9.25	3.00	24.14
2038	8.82	3.06	23.25
2039	8.39	3.12	22.34
2040	7.92	3.19	21.38
2041	7.93	3.26	21.21
2042	7.94	3.32	21.03
2043	7.92	3.39	20.84
2044	7.92	3.46	20.63
2045	7.92	3.54	20.40

Note: 2025 prices are a blend of futures/forwards and forecast prices. 2026 and beyond are forecast prices.

Appendix 5B-9: Commodity Price Forecast, VA REC

	VA REC Prices ($/MWh)		
Year	**Least Cost VCEA Compliant Case**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2025	25.75	25.75	25.75
2026	25.54	25.54	25.54
2027	28.90	28.90	28.90
2028	32.34	29.26	34.80
2029	31.21	24.62	36.46
2030	29.59	19.73	37.43
2031	26.00	16.63	35.30
2032	22.26	13.41	33.10
2033	18.37	10.05	30.77
2034	14.30	6.54	28.33
2035	10.05	2.89	25.79
2036	9.65	2.94	24.99
2037	9.25	3.00	24.14
2038	8.82	3.06	23.25
2039	8.39	3.12	22.34
2040	7.92	3.19	21.38
2041	7.93	3.26	21.21
2042	7.94	3.32	21.03
2043	7.92	3.39	20.84
2044	7.92	3.46	20.63
2045	7.92	3.54	20.40

Note: Reflects the ICF forecast price for the entire period rather than blending the ICF forecast with market prices.

Appendix 5B-10: Commodity Price Forecast, PJM RTO Capacity

	PJM RTO Capacity Prices ($/kW-yr)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	98.52	98.52	98.52
2026	111.14	111.14	111.14
2027	108.54	120.15	120.15
2028	105.73	144.28	144.28
2029	110.05	154.34	160.05
2030	108.30	138.76	144.57
2031	116.25	120.51	134.38
2032	122.59	115.21	137.93
2033	130.20	119.40	144.03
2034	142.46	123.72	150.38
2035	154.11	131.65	159.28
2036	166.97	142.60	170.34
2037	180.60	154.44	182.15
2038	194.29	167.30	194.82
2039	208.24	181.30	208.45

Appendix 5B-11: Commodity Price Forecast, PJM RTO Capacity

	RTO Capacity Prices ($/MW-day)		
Year	**Least Cost VCEA Compliant Case**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2025	269.92	269.92	269.92
2026	304.49	304.49	304.49
2027	297.37	329.18	329.18
2028	289.66	395.30	395.30
2029	301.50	422.85	438.48
2030	296.71	380.16	396.08
2031	318.49	330.16	368.16
2032	335.87	315.63	377.89
2033	356.73	327.12	394.61
2034	390.31	338.97	411.99
2035	422.23	360.69	436.38
2036	457.45	390.68	466.68
2037	494.80	423.11	499.04
2038	532.30	458.35	533.76
2039	570.53	496.70	571.10
2040	610.34	523.98	628.83
2041	634.49	542.75	669.25
2042	647.06	562.18	687.78
2043	658.94	582.32	706.85
2044	666.24	603.28	726.57
2045	674.73	617.28	730.92

Note:

1) RTO capacity prices are restated in the units used by the PJM capacity market.

Appendix 5B-12: Commodity Price Forecast, Dom Zone Capacity

	Dom Zone Capacity Prices ($/kW-yr)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	162.15	162.15	162.15
2026	137.65	137.65	137.65
2027	120.15	120.15	120.15
2028	144.28	144.28	144.28
2029	160.05	154.34	160.05
2030	144.57	138.76	144.57
2031	127.68	120.51	134.38
2032	122.59	115.21	137.93
2033	130.20	119.40	144.03
2034	142.46	123.72	150.38
2035	154.11	131.65	159.28
2036	166.97	142.60	170.34
2037	180.60	154.44	182.15
2038	194.29	167.30	194.82
2039	208.24	181.30	208.45

Appendix 5B-13: Commodity Price Forecast, Dom Zone Capacity

Year	Dom Zone Capacity Prices ($/MW-day)		
	Least Cost VCEA Compliant Case	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2025	444.26	444.26	444.26
2026	377.13	377.13	377.13
2027	329.18	329.18	329.18
2028	395.30	395.30	395.30
2029	438.48	422.85	438.48
2030	396.08	380.16	396.08
2031	349.80	330.16	368.16
2032	335.87	315.63	377.89
2033	356.73	327.12	394.61
2034	390.31	338.97	411.99
2035	422.23	360.69	436.38
2036	457.45	390.68	466.68
2037	494.80	423.11	499.04
2038	532.30	458.35	533.76
2039	570.53	496.70	571.10
2040	610.34	523.98	628.83
2041	634.49	542.75	669.25
2042	647.06	562.18	687.78
2043	658.94	582.32	706.85
2044	666.24	603.28	726.57
2045	674.73	617.28	730.92

Note:

1) RTO capacity prices are restated in the units used by the PJM capacity market.

Appendix 5B-14: Commodity Price Forecast, SO_2 Emissi

	SO_2 ($/Ton)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	1.25	1.25	1.25
2026	1.29	1.29	1.29
2027	2.07	2.07	2.07
2028	3.17	3.17	3.17
2029	3.36	3.36	3.36
2030	3.42	3.42	3.42
2031	3.49	3.49	3.49
2032	3.56	3.56	3.56
2033	2.42	2.42	2.42
2034	2.47	2.47	2.47
2035	2.52	2.52	2.52
2036	2.57	2.57	2.57
2037	2.62	2.62	2.62
2038	2.67	2.67	2.67
2039	2.73	2.73	2.73
2040	2.79	2.79	2.79
2041	2.84	2.84	2.84
2042	2.90	2.90	2.90
2043	2.96	2.96	2.96
2044	3.02	3.02	3.02
2045	3.09	3.09	3.09

Note:

1) CSAPR SO2 and nationwide SO2 prices are used as the SO2 market price.

Appendix 5B-15: Commodity Price Forecast, NOx Emission Allowances

	CSAPR Ozone NOx ($/Ton)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	787.50	787.50	787.50
2026	800.16	800.52	799.72
2027	1,056.96	1,091.01	831.38
2028	1,450.16	2,363.44	937.09
2029	2,528.20	6,432.36	1,554.95
2030	2,609.85	10,541.99	2,085.60
2031	2,278.84	8,080.58	1,709.13
2032	1,946.21	7,416.95	1,376.59
2033	1,586.50	2,276.81	1,089.96
2034	1,223.31	1,581.65	654.90
2035	932.71	1,222.61	226.88
2036	385.58	642.63	2.57
2037	131.07	327.66	2.62
2038	2.67	2.67	2.67
2039	2.73	2.73	2.73
2040	2.79	2.79	2.79
2041	2.84	2.84	2.84
2042	2.90	2.90	2.90
2043	2.96	2.96	2.96
2044	3.02	3.02	3.02
2045	3.09	3.09	3.09

Appendix 5B-16: Commodity Price Forecast, NOx Emission Allowances

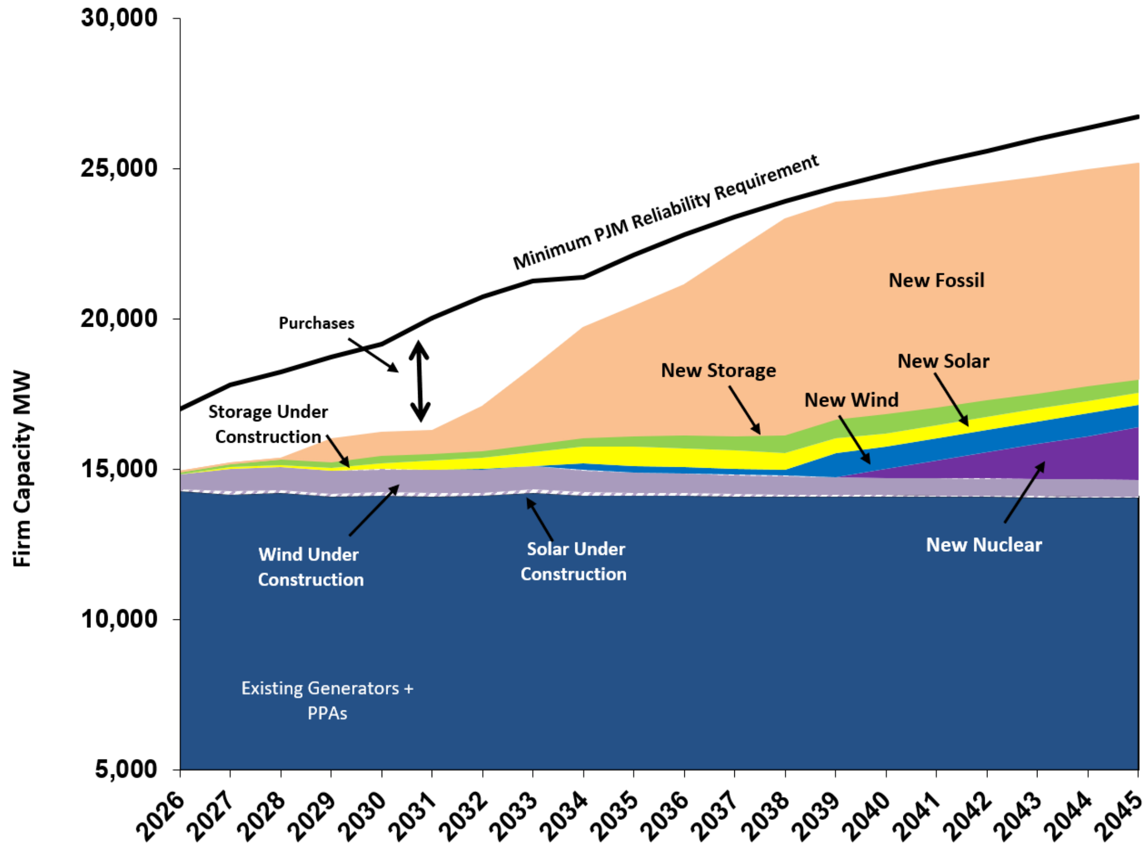
	CSAPR Annual NOx ($/Ton)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	2.50	2.50	2.50
2026	2.57	2.57	2.57
2027	2.87	2.87	2.87
2028	3.26	3.26	3.26
2029	3.36	3.36	3.36
2030	3.42	3.42	3.42
2031	3.49	3.49	3.49
2032	3.56	3.56	3.56
2033	2.42	2.42	2.42
2034	2.47	2.47	2.47
2035	2.52	2.52	2.52
2036	2.57	2.57	2.57
2037	2.62	2.62	2.62
2038	2.67	2.67	2.67
2039	2.73	2.73	2.73
2040	2.79	2.79	2.79
2041	2.84	2.84	2.84
2042	2.90	2.90	2.90
2043	2.96	2.96	2.96
2044	3.02	3.02	3.02
2045	3.09	3.09	3.09

Appendix 5B-17: Commodity Price Forecast, CO_2

	Federal CO_2 (\$/Ton)		
Year	Least Cost VCEA Compliant Case	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2025	0.00	0.00	0.00
2026	0.00	0.00	0.00
2027	0.00	0.00	0.00
2028	0.00	0.00	0.00
2029	0.00	0.00	0.00
2030	0.00	0.00	0.00
2031	0.00	0.00	0.00
2032	0.00	0.00	0.00
2033	0.00	0.00	0.00
2034	0.00	0.00	0.00
2035	0.00	0.00	0.00
2036	0.00	0.00	0.00
2037	0.00	0.00	0.00
2038	0.00	0.00	0.00
2039	0.00	0.00	0.00

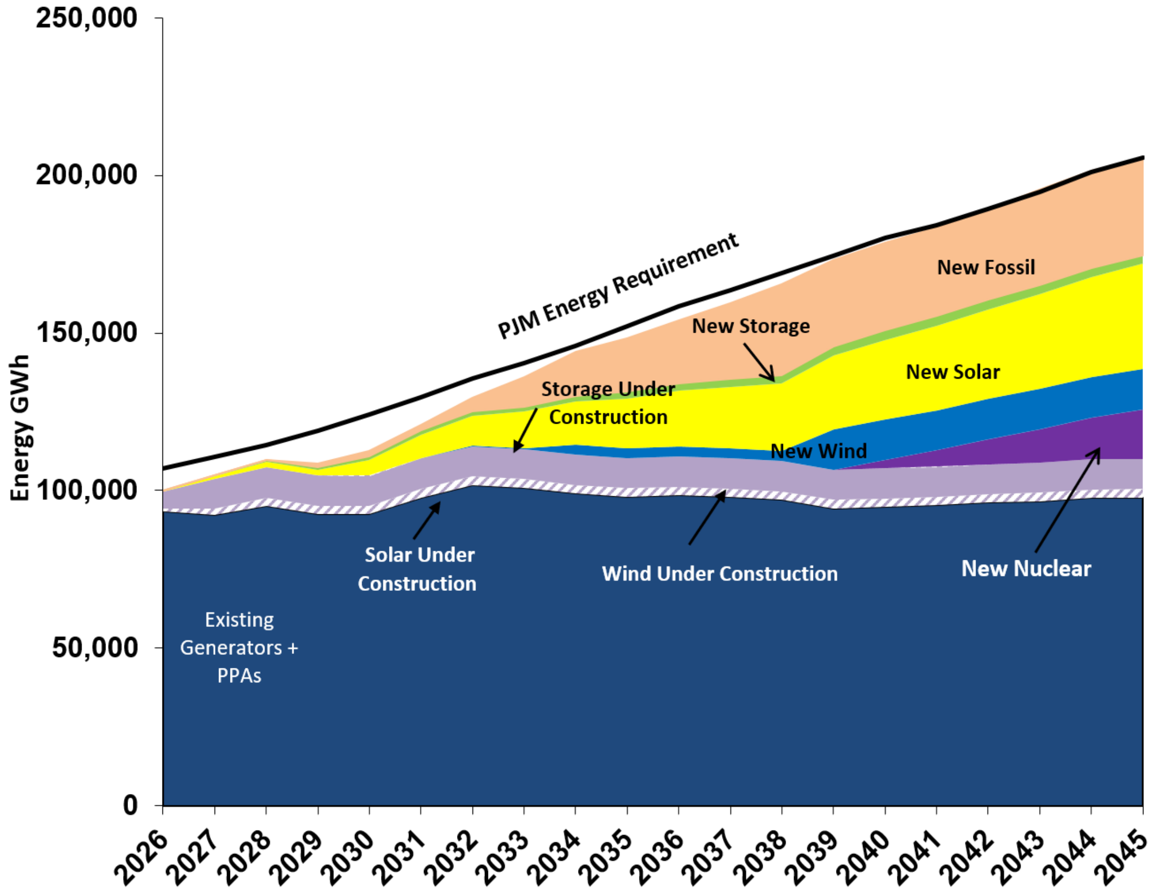
Appendix 5C: Company Preferred Plan - Summer Capacity, Energy, and RECs

Capacity



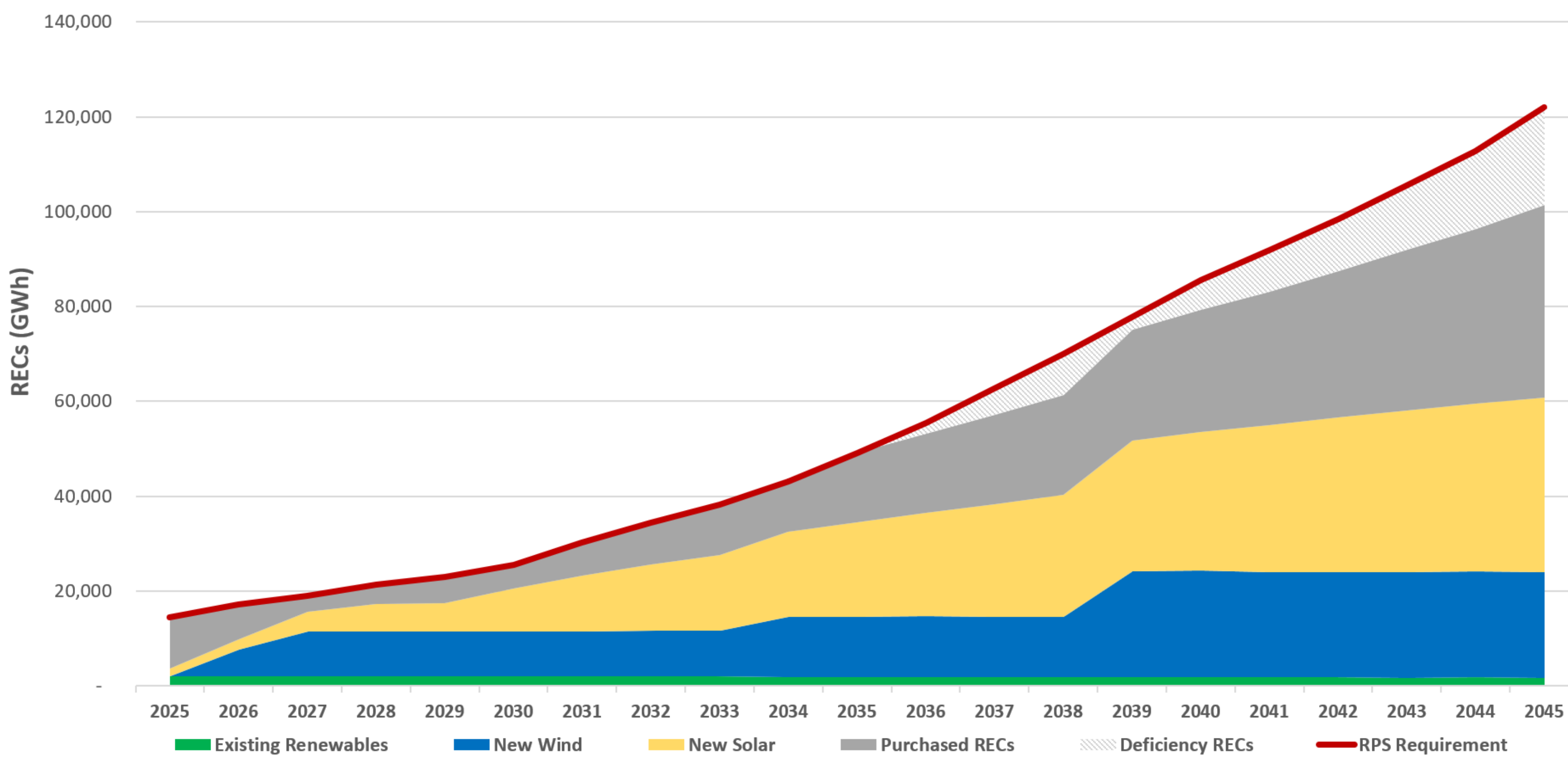
Appendix 5C: Company Preferred Plan- Summer Capacity, Energy, and RECs

Energy



Appendix 5C: Company Preferred Plan- Summer Capacity, Energy, and RECs

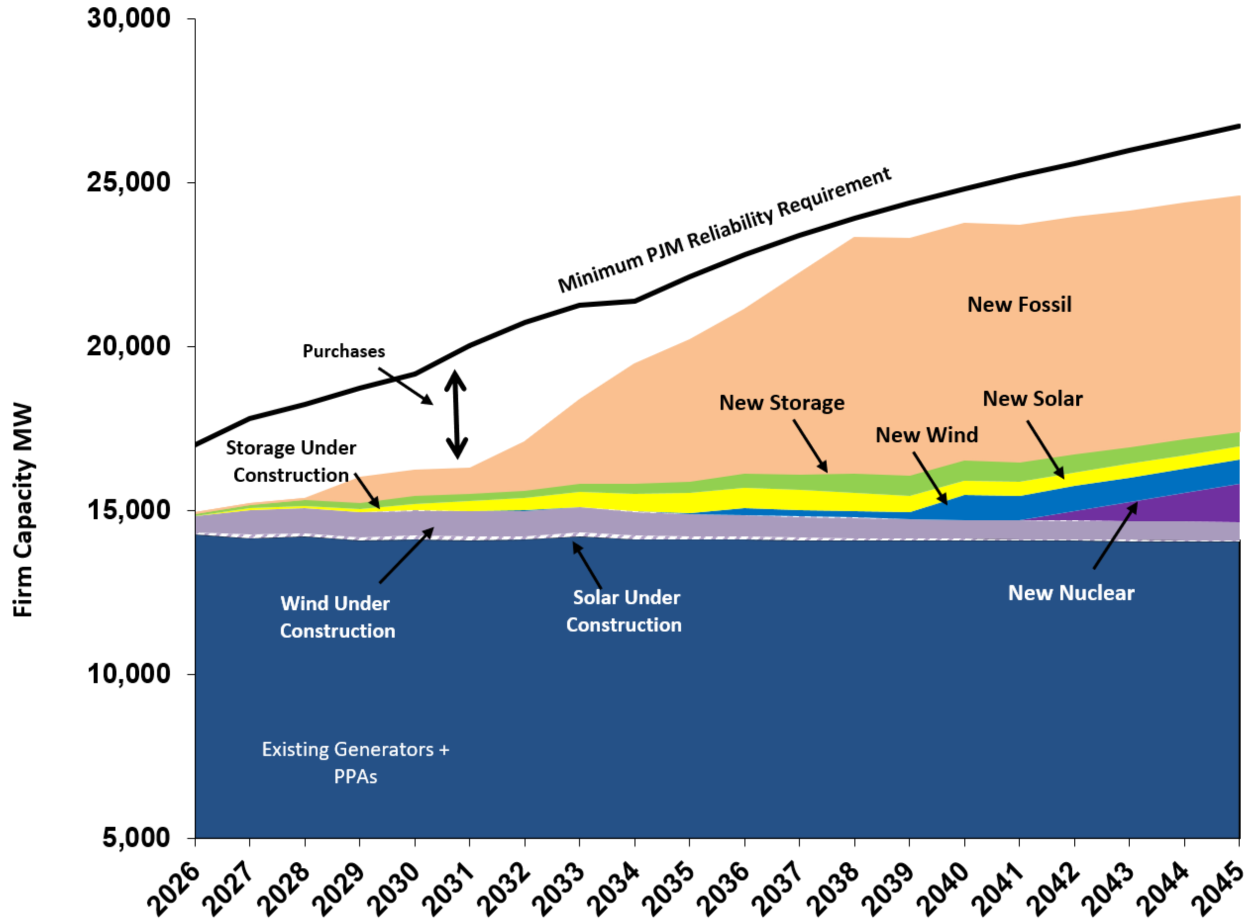
RECs



Note: *After processing the figures underlying Appendix 5C, the Company discovered a de minimus issue related to Storage Projects, which resulted in a Firm Capacity overstatement not exceeding 17MW annually and an understatement not exceeding 28MW annually.*

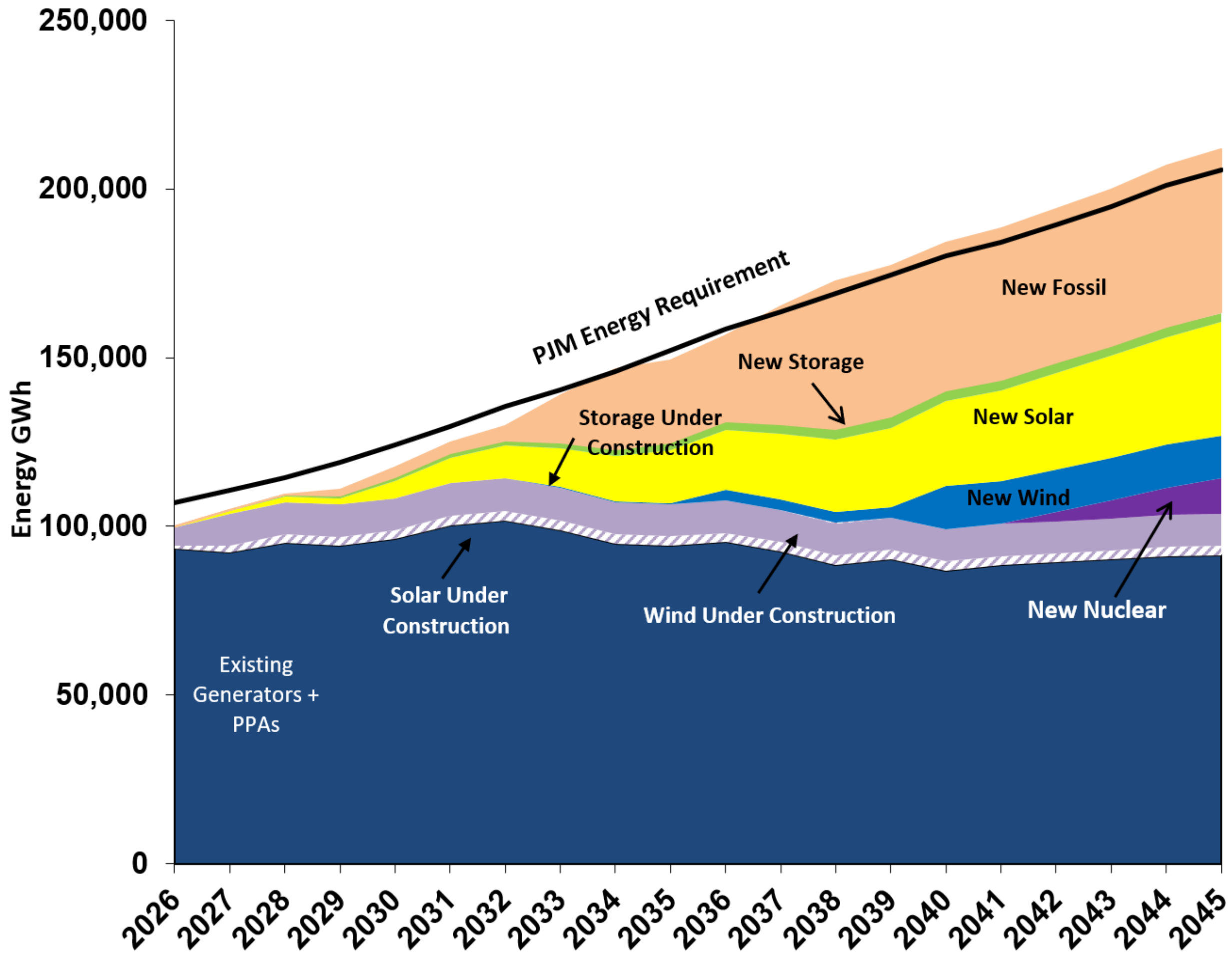
Appendix 5C: Least Cost VCEA Compliant without EPA - Summer Capacity, Energy, and RECs

Capacity



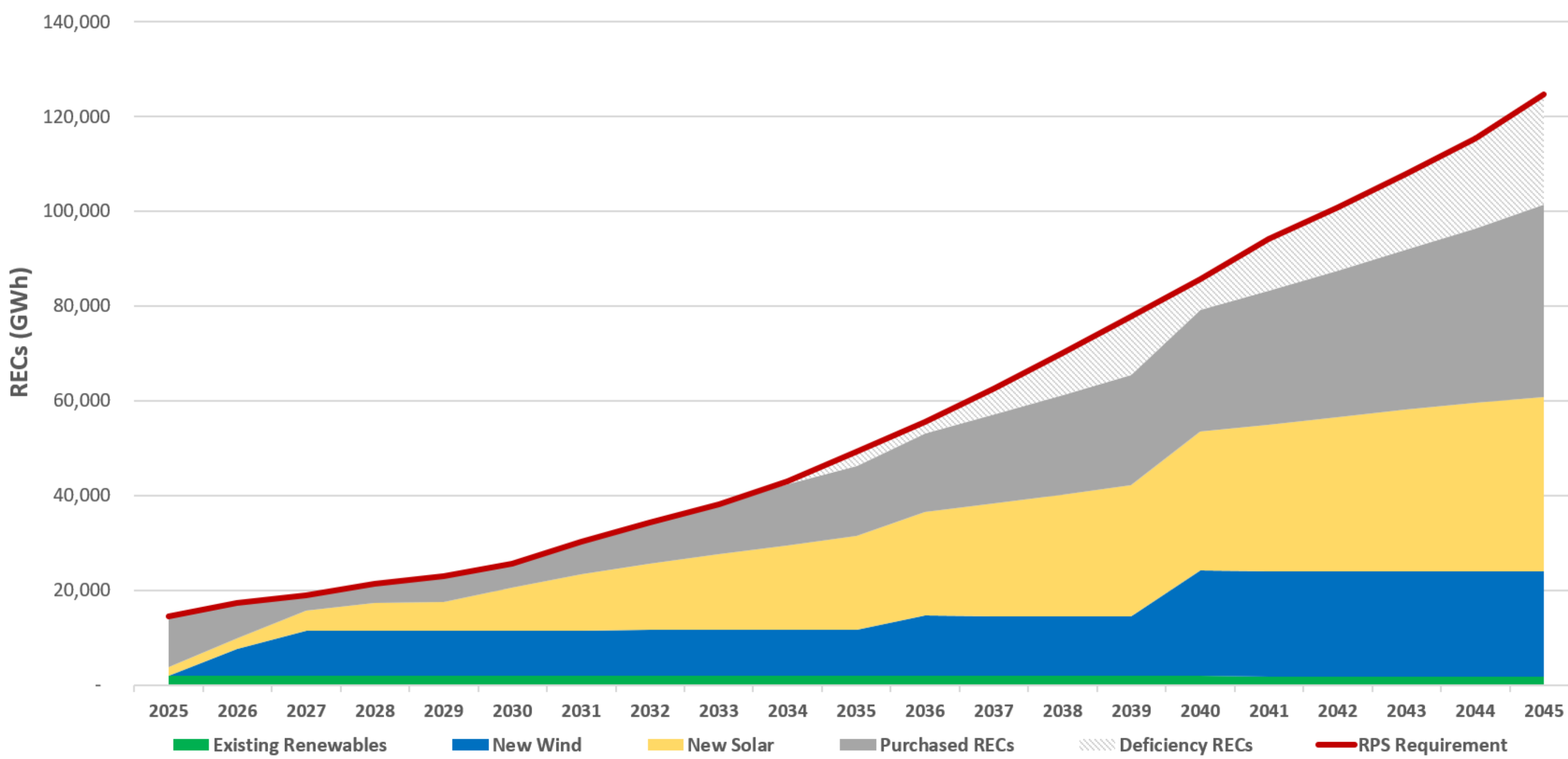
Appendix 5C: Least Cost VCEA Compliant without EPA - Summer Capacity, Energy, and RECs

Energy



Appendix 5C: Least Cost VCEA Compliant without EPA - Summer Capacity, Energy, and RECs

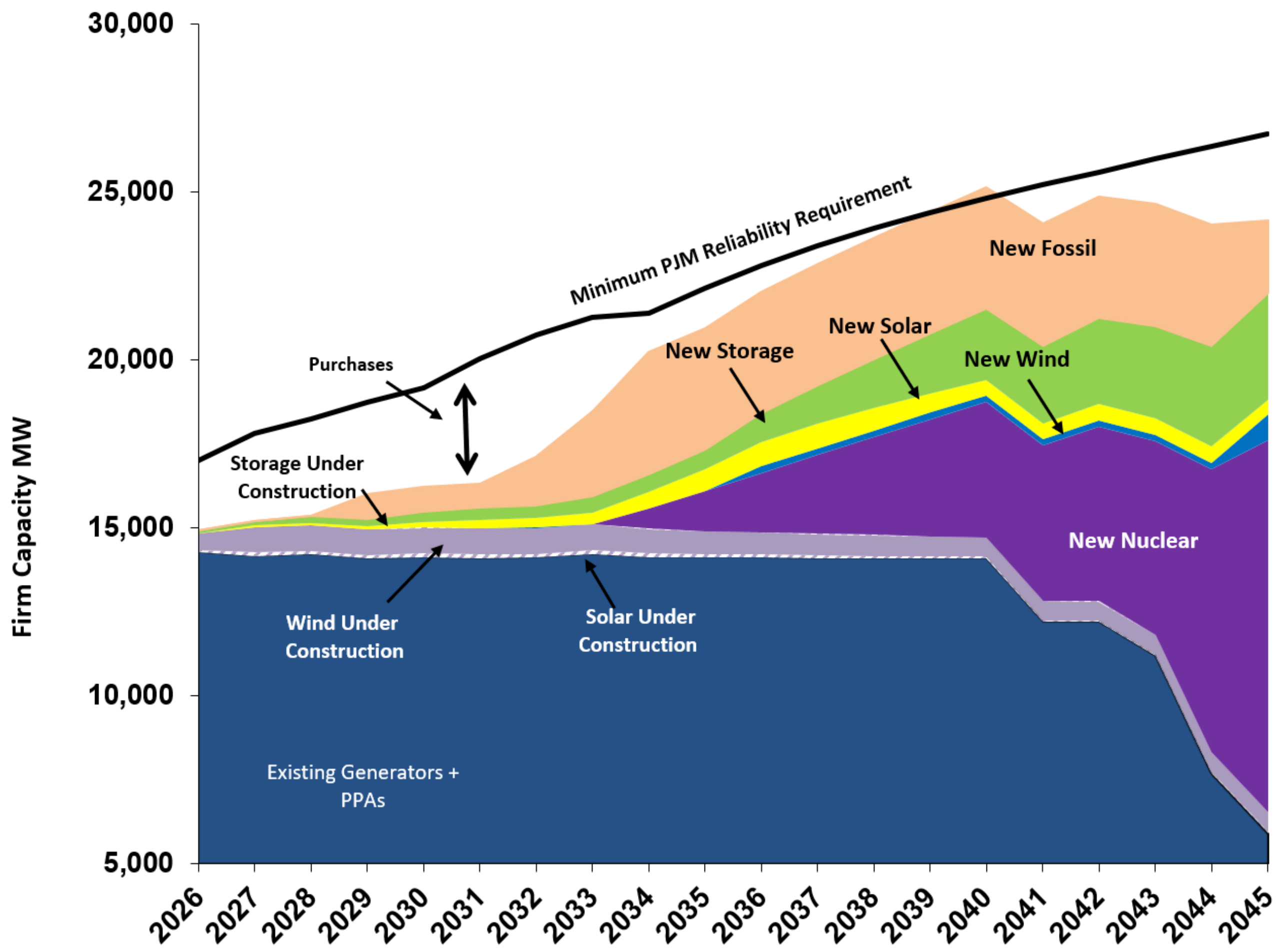
RECs



Note: *After processing the figures underlying Appendix 5C, the Company discovered a de minimus issue related to Storage Projects, which resulted in a Firm Capacity overstatement not exceeding 17MW annually and an understatement not exceeding 28MW annually.*

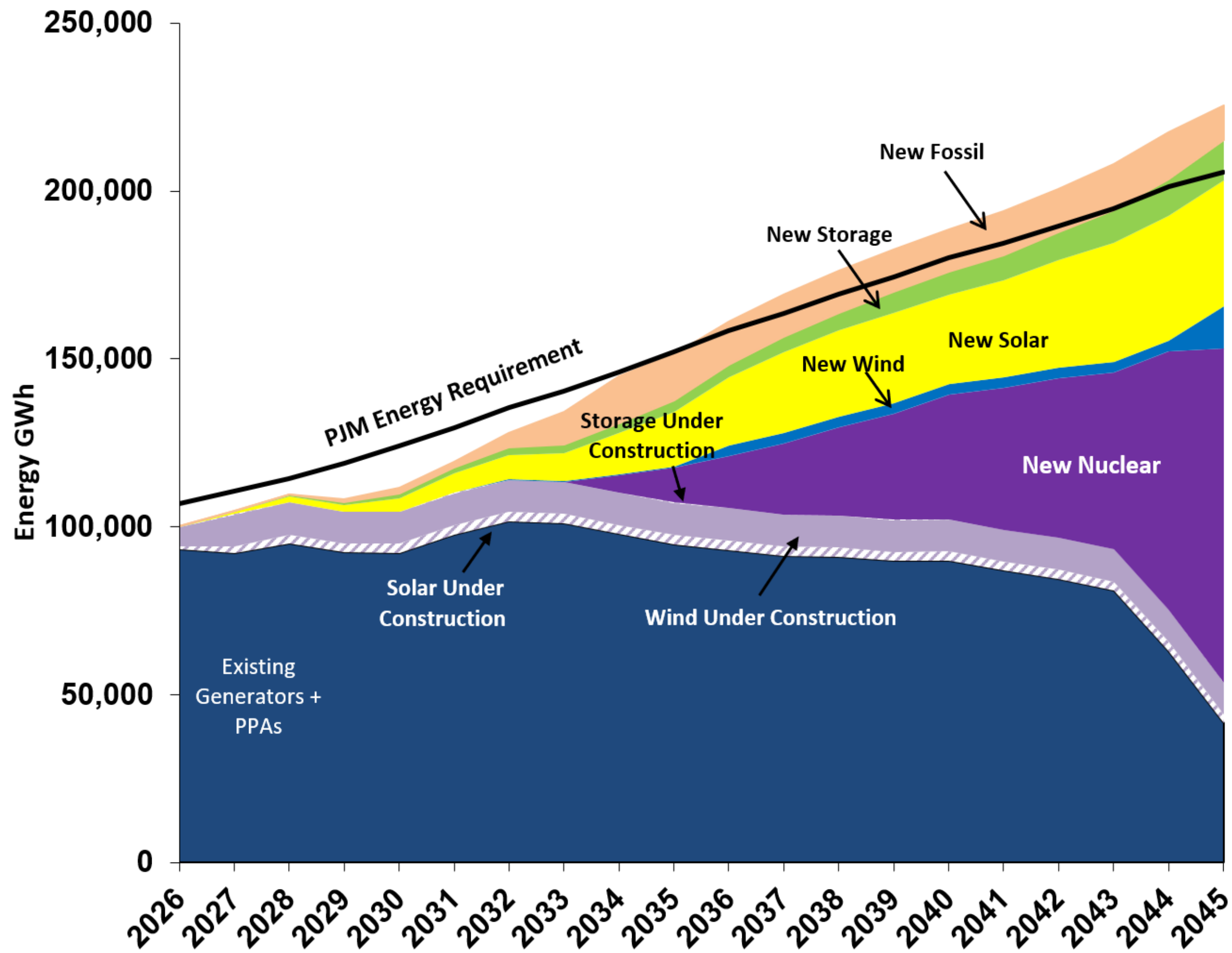
Appendix 5C: Forced Retirements by 2045 - Summer Capacity, Energy, and RECs

Capacity



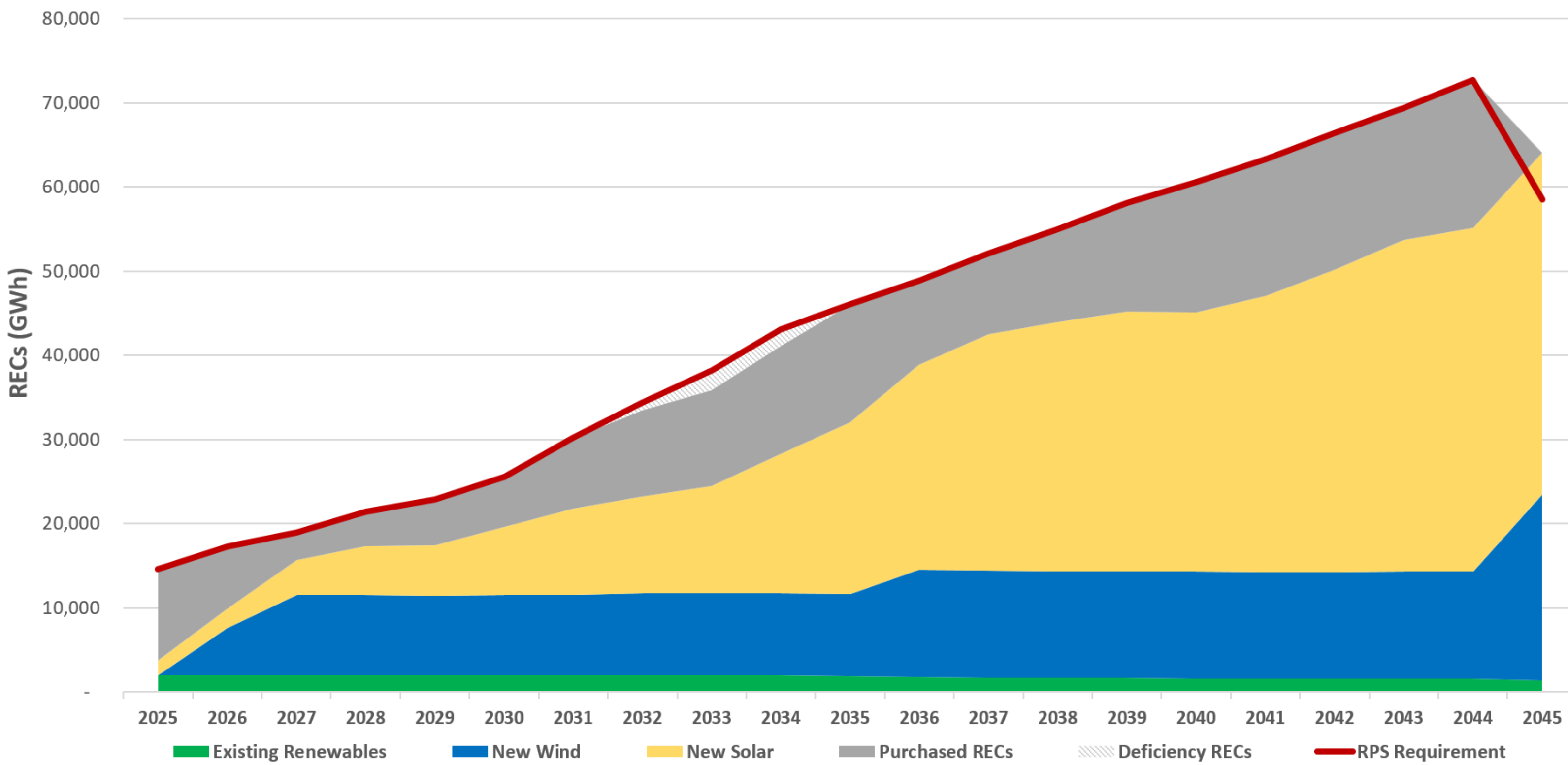
Appendix 5C: Forced Retirements by 2045 - Summer Capacity, Energy, and RECs

Energy



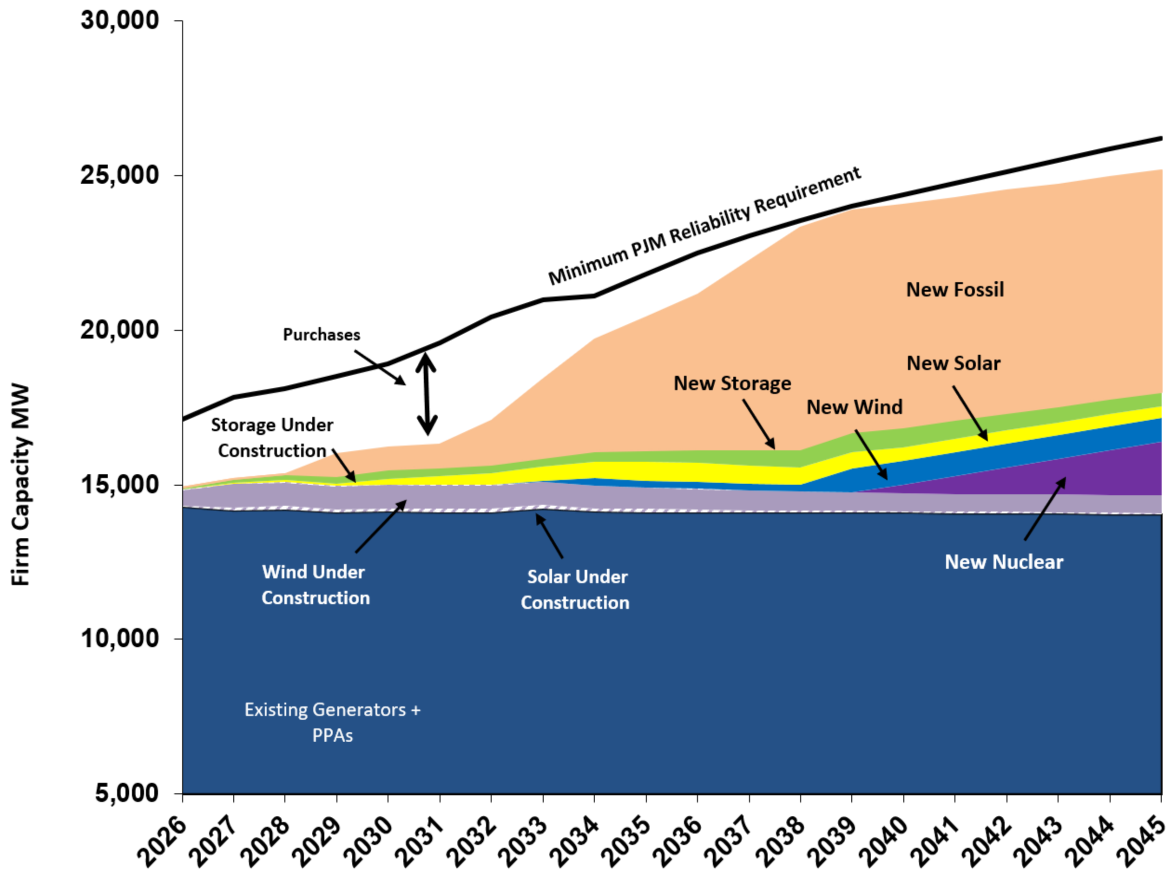
Appendix 5C: Forced Retirements by 2045 - Summer Capacity, Energy, and RECs

RECs



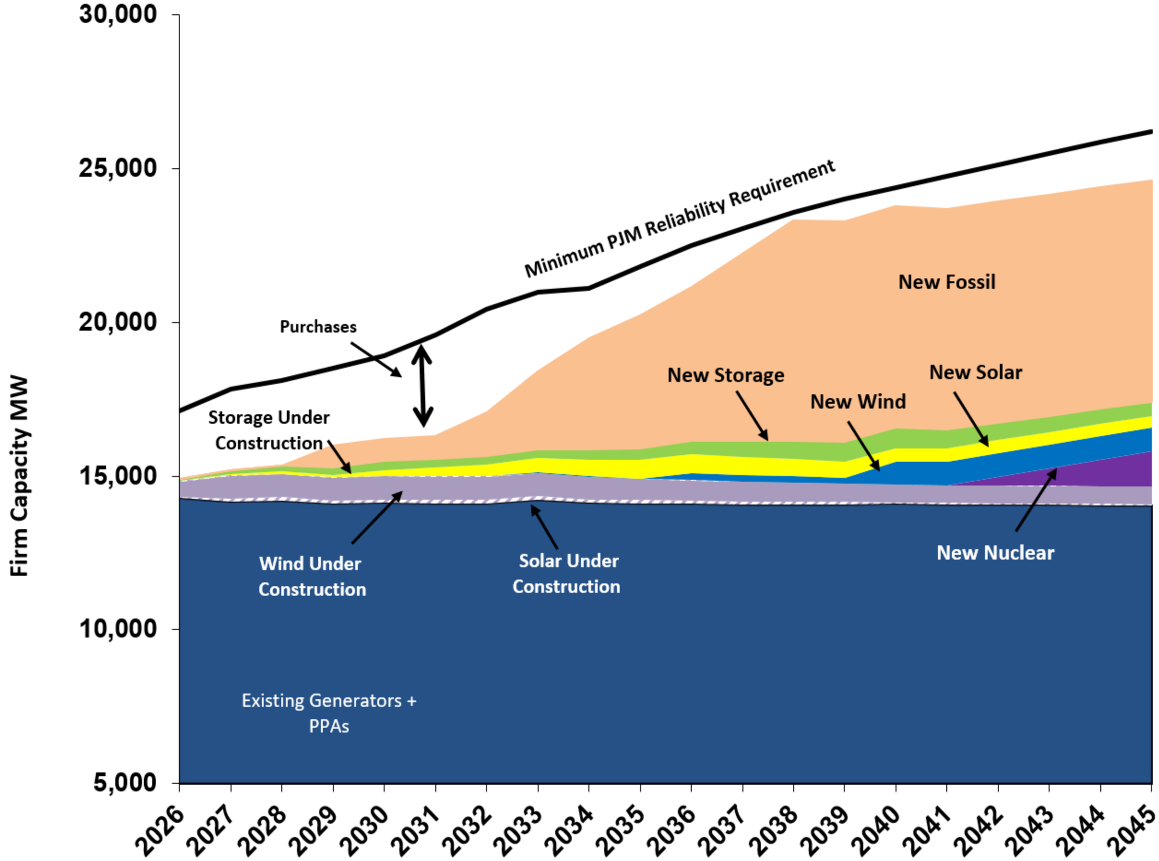
Note: *After processing the figures underlying Appendix 5C, the Company discovered a de minimus issue related to Storage Projects, which resulted in a Firm Capacity overstatement not exceeding 17MW annually and an understatement not exceeding 28MW annually.*

Appendix 5C: Winter Capacity Charts
Company Preferred Plan



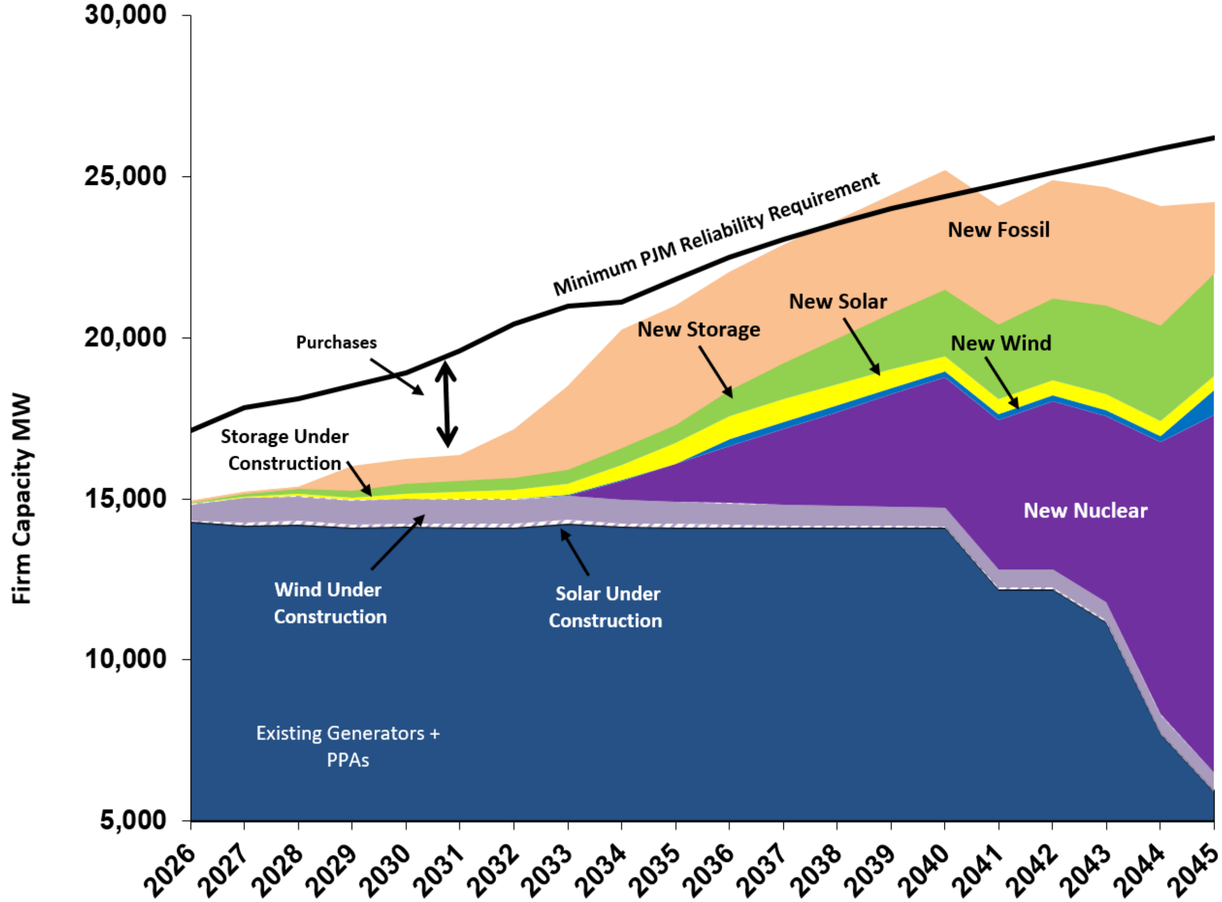
Plan A: (Company Preferred Plan) Least Cost VCEA Compliant

Appendix 5C: Winter Capacity Charts
Least Cost VCEA Compliant without EPA



Plan B: Least Cost VCEA Compliant without EPA

Appendix 5C: Winter Capacity Charts
Forced Retirements by 2045



Plan C: Forced Retirements by 2045