McGuireWoods

McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, VA 23219-3916
Phone: 804.775.1000
Fax: 804.775.1061
www.mcguirewoods.com

Vishwa B. Link
Direct: 804.775.4330
vlink@mcguirewoods.com

October 15, 2024

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 2024 Integrated Resource Plan
filing pursuant to Va. Code § 56-597 et seq.
Case No. PUR-2024-00184

Dear Mr. Logan:

Please find enclosed for electronic filing in the above-captioned proceeding the 2024 Integrated Resource Plan (the "2024 IRP") 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 2024 IRP that comply with the Va. Code, the Guidelines, and the requirements of relevant prior Commission orders. Also enclosed is a copy of the Company's proposed notice in this proceeding pursuant to Section E of the Guidelines.

Along with the 2024 IRP, the Company is filing its Motion for Entry of a Protective Order and Additional Protective Treatment for Extraordinarily Sensitive Information under separate cover.

Separate from these filings with the Commission, the Company is providing Commission Staff with the Guidelines schedules associated with the 2024 IRP in electronic format pursuant to Section E of the Guidelines, and is providing a copy of the 2024 IRP to members of the General Assembly pursuant to Va. Code § 56-599.

To the extent the Commission modifies Rule 260 of the Rules of Practice and Procedure, 5 VAC 5-20-260, in its procedural order for this proceeding related to the deadline to respond to discovery requests, the Company respectfully requests that the Commission allow the Company, Staff, and all respondents at least five (5) *business* days to respond or object to interrogatories or requests for production of documents after the receipt of same. Requiring the response time to be in *business* days instead of *calendar* days allows for intervening weekends and holidays to not be counted and allows the Company and parties time for more fulsome and complete responses. Granting this request will not prejudice Staff or any party in this proceeding and will allow sufficient time to respond to what the Company expects to be a significant amount of discovery over the next several months.

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.
C. Meade Browder, Jr., Esq.
Paul E. Pfeffer, Esq.
Lisa R. Crabtree, Esq.
Sarah B. Nielsen, Esq.
Nicole M. Allaband, Esq.

Order / Guideline	Requirement	2024 IRP Section
Va. Code § 56-598 (1)	An IRP should: 1. Integrate, over the planning period, the electric utility's forecast of demand for electric generation supply with recommended plans to meet that forecasted demand and assure adequate and sufficient reliability of service: a. Generating electricity from generation facilities that it currently operates or intends to construct or purchase; b. Purchasing electricity from affiliates and third parties; c. Reducing load growth and peak demand growth through cost-effective demand reduction programs; and d. Utilizing energy storage facilities to help meet forecasted demand and assure adequate and sufficient reliability of service.	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years
Va. Code § 56-598 (2)	An IRP should: 2. Identify a portfolio of electric generation supply resources, including purchased and self-generated electric power, that: a. Consistent with § 56-585.1, is most likely to provide the electric generation supply needed to meet the forecasted demand, net of any reductions from demand side programs, so that the utility will continue to provide reliable service at reasonable prices over the long term; and b. Will consider low cost energy/capacity available from short-term or spot market transactions, consistent with a reasonable assessment of risk with respect to both price and generation supply availability over the term of the plan.	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Chapter 3.1.2** Power Purchase Agreements
Va. Code § 56-598 (3)	An IRP should: 3. Reflect a diversity of electric generation supply and cost-effective demand reduction contracts and services so as to reduce the risks associated with an over-reliance on any particular fuel or type of generation demand and supply resources and be consistent with the Commonwealth's energy policies as set forth in § 45.2-1706.1.	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years
Va. Code § 56-598 (4)	An IRP should: 4. Include such additional information as the Commission requests pertaining to how the electric utility intends to meets its obligation to provide electric generation service for use by its retail customers over the planning period.	**2024 IRP** Reference Index
Va. Code § 56-599 (A)	Each electric utility shall file an updated integrated resource plan by October 15, in each year immediately preceding the year the utility is subject to a biennial review of rates for generation and distribution services filing. A copy of each integrated resource plan shall be provided to the Chairmen of the House Committee on Labor and Commerce, the Chairman of the Senate Committees on Commerce and Labor, and to the Chairman of the Commission on Electric Utility Regulation. After January 1, 2024, each electric utility not subject to an annual review shall file an annual update to the integrated resource plan by October 15, in each year that the utility is subject to review of rates for generation and distribution services filing.	**2024 IRP**
Va. Code § 56-599 (A)	All updated integrated resource plans shall comply with the provisions of any relevant order of the Commission establishing guidelines for the format and contents of updated and revised integrated resource plans. Each integrated resource plan shall consider options for maintaining and enhancing rate stability, energy independence, economic development including retention and expansion of energy-intensive industries, and service reliability.	**2024 IRP** Reference Index
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 1. Entering into short-term and long-term electric power purchase contracts.	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Chapter 3.1.2** Power Purchase Agreements
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 2. Owning and operating electric power generation facilities.	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Chapter 3.2** Building Renewable Energy Resources **Chapter 3.5** Nuclear **Chapter 3.6** Reliability Resources Under Development
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 3. Building new generation facilities.	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Chapter 3.2** Building Renewable Energy Resources **Chapter 3.5** Nuclear **Chapter 3.6** Reliability Resources Under Development
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 4. Relying on purchases from the short term or spot markets.	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Chapter 2.2** Changes to the PJM Market Affect the Planning Environment
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 5. Making investments in demand-side resources, including energy efficiency and demand-side management services;	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Chapter 3.2.5** Energy Efficiency and Demand Response as Resources to Manage Customer Load **Chapter 3.8.2** Demand-Side Management **Appendix 3D** Demand-Side Management

Order / Guideline	Requirement	2024 IRP Section
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 6. Taking such other actions, as the Commission may approve, to diversify its generation supply portfolio and ensure that the electric utility is able to implement an approved plan;	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 7. The methods by which the electric utility proposes to acquire the supply and demand resources identified in its proposed integrated resource plan;	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 8. The effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities;	**Chapter 5.1** Overview of the Primary Portfolios **Appendix 5A** Environmental Regulations
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 9. The most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations;	**Chapter 5.2** Modeling Results for the Portfolios **Chapter 5.3** Sensitivity Analyses
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 10. Long-term electric distribution grid planning and proposed electric distribution grid transformation projects, including a comprehensive assessment of the potential application of grid-enhancing technologies and advanced conductors in a manner that ensures grid reliability and safeguards the cybersecurity and physical security of the electric distribution grid. An electric utility that does not include grid-enhancing technologies or advanced conductors in an integrated resource plan shall include a detailed explanation of why such technologies or conductors are not included in such plan.	**Chapter 3.3** Distribution Grid Transformation **Appendix 3L** Distribution **Appendix 3M** Grid Transformation Plan **Appendix 3N** 2024 Integrated Distribution Planning Roadmap
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 11. Developing a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity; and	**Chapter 3.8.2** Demand-Side Management **Appendix 3D** Demand-Side Management
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 12. Developing a long-term plan to integrate new energy storage facilities into existing generation and distribution assets to assist with grid transformation.	**Chapter 3.2.4** Energy Storage **Chapter 3.7** Future Supply-Side Resource Options
Va. Code § 56-599 (C)	As part of preparing any integrated resource plan pursuant to this section, each utility shall conduct a facility retirement study for owned facilities located in the Commonwealth that emit carbon dioxide as a byproduct of combusting fuel and shall include the study results in its integrated resource plan. Upon filing the integrated resource plan with the Commission, the utility shall contemporaneously disclose the study results to each planning district commission, county board of supervisors, and city and town council where such electric generation unit is located, the Department of Energy, the Department of Housing and Community Development, the Virginia Employment Commission, and the Virginia Council on Environmental Justice. The disclosure shall include (i) the driving factors of the decision to retire and (ii) the anticipated retirement year of any electric generation unit included in the plan. Any electric generating facility with an anticipated retirement date that meets the criteria of § 45.2-1701.1 shall comply with the public disclosure requirements therein.	Not Applicable
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
Chapter 296 Enactment Clause 18	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. Considerations 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 and 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 may seem appropriate.	**Appendix 3D** Demand-Side Management **Appendix 3J** National Comparison Analyses
Guideline (A)	In order to understand the basis for the utility's plan, the IRP filing shall include a narrative summary detailing the underlying assumptions reflected in its forecast as further described in the guidelines. To better follow the utility's planning process, the narrative shall include a description of the utility's rationale for the selection of any particular generation addition or demand-side management program to fulfill its forecasted need. Such description should include the utility's evaluation of its purchase options and cost/benefit analyses for each resource option to confirm and justify each resource option it has chosen. Such narrative shall also describe the planning process including timelines and appropriate reviews and/or approvals of the utility's plan. For members of PJM Interconnection, LLC ("PJM"), the narrative should describe how the IRP incorporates the PJM planning and implementation processes and how it will satisfy PJM load obligations.	**Chapter 2** Current Challenges to Reliability **Chapter 3** Producing Cleaner Energy While Ensuring Reliability **Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Appendix 5B** Cost Assumptions

Order / Guideline	Requirement	2024 IRP Section
Guideline (A)	These guidelines also include sample schedules to supplement this narrative discussion and assist the utilities in developing a tabulation of the utility's forecast for at least a 15-year period and identify the projected supply-side or demand-side resource additions and solutions to adequately and reliably meet the electricity needs of the Commonwealth. This tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the same period. These guidelines also direct that all IRP filings include information to comparably evaluate various supply-side technologies and demand-side programs and technologies on an equivalent basis as more fully described below in Section F(7).	See References for Guideline (F)(7) and Schedules
Guideline (C)(1)	1. Forecast. A three-year historical record and a 15-year forecast of the utility's native load requirements, the utility's PJM load obligations if appropriate, and other system capacity or firm energy obligations for each peak season along with the supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads, and the reserve margin thus produced.	**Chapter 2.1** Load Forecast **Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Appendix 2B-8** Projected Summer & Winter Peak Load & Energy Forecast **Appendix 2B-9** Required Reserve Margin (for VCEA with EPA) **Appendix 5C** Capacity, Energy, and RECs for the Primary Portfolios
Guideline (C)(2)	2. Option analyses. A comprehensive analysis of all existing and new resource options (supply- and demand-side), including costs, benefits, risks, uncertainties, reliability, and customer acceptance where appropriate, considered and chosen by the utility for satisfaction of native load requirements and other system obligations necessary to provide reliable electric utility service, at the lowest reasonable cost, over the planning period.	**Chapter 3** Producing Cleaner Energy While Ensuring Reliability
Guideline (C)(2)(a)	a. Purchased Power - assess the potential costs and benefits of purchasing power from wholesale power suppliers and power marketers to supply it with needed capacity and describe in detail any decision to purchase electricity from the wholesale power market.	**Chapter 2.2** Changes to the PJM Market Affecting the Plan Environment
Guideline (C)(2)(b)	b. Supply-side Energy Resources - assess the potential costs and benefits of reasonably available traditional and alternative supply-side energy resource options, including, but not limited to technologies such as, nuclear, pulverized coal, clean coal, circulating fluidized bed, wood, combined cycle, integrated gasification combined cycle, and combustion turbine, as well as renewable energy resources such as those derived from sunlight, wind, falling water, sustainable biomass, energy from waste, municipal solid waste, wave motion, tides, and geothermal power.	**Chapter 3** Producing Cleaner Energy While Ensuring Reliability
Guideline (C)(2)(c)	c. Demand-side Options - assess the potential costs and benefits of programs that promote demand-side management. For purposes of these guidelines, peak reduction and demand response programs and energy efficiency and conservation programs will collectively be referred to as demand-side options.	**Chapter 3.2.5** Energy Efficiency and Demand Response as Resources to Manage Customer Load **Appendix 3D** Demand-Side Management
Guideline (C)(2)(d)	d. Evaluation of Resource Options - analyze potential resource options and combinations of resource options to serve system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction or implementation costs, transmission and distribution costs, environmental impacts and compliance costs.	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years
Guideline (C)(3)	3. Data availability. To the extent the information requested is not currently available or is not applicable, the utility will clearly note and explain this in the appropriate location in the plan, narrative, or schedule.	As Applicable
Guideline (D)	Each utility shall provide a narrative summary detailing the major trends, events, and/or conditions reflected in the forecasted data submitted in response to these guidelines.	**Chapter 2** Current Challenges to Reliability **Chapter 3.4** Resource Adequacy **Chapter 5.4** Extreme Weather Analysis
Guideline (D)(1)	1. Discussion regarding the forecasted peak load obligation and energy requirements. PJM members should also discuss the relationship of the utility's expected non-coincident peak and its expected PJM related load obligations.	**Chapter 2.1** Load Forecast
Guideline (D)(2)	2. Discussion regarding company goals and plans in response to directives of Chapters 23 and 24 of Title 56 of the Code of Virginia, including compliance with energy efficiency, energy conservation, demand-side and response programs, and the provision of electricity from renewable energy resources.	**Executive Summary** **Chapter 3** Producing Cleaner Energy While Ensuring Reliability **Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Appendix 3C** Generation Under Construction **Appendix 3E** Description of Active DSM Programs **Appendix 3F** Recently Approved Program
Guideline (D)(3)	3. Discussion regarding the complete planning process, including timelines, assumptions, reviews, approvals, etc., of the company's plans. For PJM members, the discussion should also describe how the IRP integrates into the complete planning process of PJM.	**Chapter 2.3** Transmission Considerations **Chapter 2.4** Generation Considerations **Appendix 5B** Cost Assumptions

Order / Guideline	Requirement	2024 IRP Section
Guideline (D)(4)	4. Discussion of the critical input assumptions to determine the load forecast and expected changes in load growth including factors such as energy conservation, efficiency, load management, demand response, variations in customer class sizes, expected levels of economic activity, variations in fuel prices and appliance inventories, etc.	**Chapter 2.1** Load Forecast **Appendix 2B-13** Economic Assumptions
Guideline (D)(5)	5. Discussion regarding cost/benefit analyses and the results of such factors on this plan, including the methodology used to consider equal or comparable treatment afforded both the demand-side options and supply-side resources.	**Chapter 3.1** Supply-Side Generating Resources **Appendix 3D** Demand-Side Management **Appendix 5B** Cost Assumptions
Guideline (D)(6)	6. Planned changes in operating characteristics such as unit retirements, unit uprates or derates, changes in unit availabilities, changes in capacity resource mix, changes in fuel supplies or transport, emissions compliance, unit performance, etc.	**Chapter 3.2** Producing Cleaner Energy While Ensuring Reliability **Appendix 3B-10** Potential Unit Retirements **Appendix 3B-11** Planned Changes to Existing Generation Units **Appendix 5A** Environmental Regulations **Appendix 5B** Cost Assumptions
Guideline (D)(7)	7. Discussion regarding the effectiveness of the utility's IRP to meet its load obligations with supply-side and demand-side resources to enable the utility to provide reliable service at reasonable prices over the long term.	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years **Chapter 4.2** Virginia Bill Analysis
Guideline (E)	By September 1, 2009, and every two years thereafter, each utility shall file with the Commission its then current integrated resource plan, which shall include all information required by these guidelines for the ensuing 15-year planning period along with the prior three-year historical period. The process and analyses shall be described in a narrative discussion and the results presented in tabular format using an EXCEL spreadsheet format, similar to the attached sample schedules, and be provided in both printed and electronic media. For those utilities that operate as part of a multi-state integrated power system, the schedules should be submitted for both the individual company and the generation planning pool of which the utility is a member. The top line stating the company name should indicate that the data reflects the individual utility company or the total system. For partial ownership of any facility, please provide the percent ownership and footnote accordingly.	**2024 IRP**
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 3.8** 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.	Motion for Protective Order
Guideline (E)	As § 56-599 E requires the giving of notice and an opportunity to be heard, each utility shall also include a copy of its proposed notice to be used to afford such an opportunity.	**2024 IRP** Proposed Notice
Guideline (F)(1)	1. Forecast of Load. The forecast shall include descriptions of the methods, models, and assumptions used by the utility to prepare its forecasts of its loads, requirements associated with the utility's PJM load obligation (MW) if appropriate, the utility's peak load (MW) and energy sales (MWh) and the variables used in the models	**Chapter 2.1** Load Forecast **Appendix 2A** Load Forecast Methodologies
Guideline (F)(1)(a)	a. The most recent three-year history and 15-year forecast of energy sales (kWh) by each customer class	**Appendix 2B-1** Total Sales by Customer Class (DOM LSE) (GWh) **Appendix 2B-2** Virginia Sales by Customer Class (DOM LSE) (GWh) **Appendix 2B-3** North Carolina Sales by Customer Class (DOM LSE) (GWh)
Guideline (F)(1)(b)	b. The most recent three-year history and 15-year forecast of the utility's peak load and the expected load obligation to satisfy PJM's coincident peak forecast if appropriate, and the utility's coincident peak load and associated noncoincident peak load for summer and winter seasons of each year (prior to any DSM), annual energy forecasts, and resultant reserve margins. During the forecast period, the tabulation shall also indicate the projected effects of incremental demand-side options on the forecasted annual energy and peak loads	**Appendix 2B-8** Projected Summer & Winter Peak Load & Energy Forecast **Appendix 2B-9** Required Reserve Margin (for VCEA with EPA)
Guideline (F)(1)(c)	c. Where future resources are required, a description and associated characteristics of the option that the utility proposes to use to address the forecasted need	**Chapter 3.2** Building Renewable Energy Resources **Chapter 3.5** Nuclear **Chapter 3.6** Reliability Resources Under Development **Chapter 3.7** Future Supply-Side Resource Options

Order / Guideline	Requirement	2024 IRP Section
Guideline (F)(2)	2. Supply-side Resources. The forecast shall provide data for its existing and planned electric generating facilities (including planned additions and retirements and rating changes, as well as firm purchase contracts, including cogeneration and small power production) and a narrative description of the driver(s) underlying such anticipated changes such as expected environmental compliance, carbon restrictions, technology enhancements, etc.	**Chapter 2** Current Challenges to Reliability **Chapter 3** Producing Cleaner Energy While Ensuring Reliability **Appendix 5A** Environmental Regulations
Guideline (F)(2)(a)	a. Existing Generation. For existing units in service: i. Type of fuel(s) used ii. Type of unit (e.g., base, intermediate, or peaking) iii. Location of each existing unit iv. Commercial Operation Date v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW)) vi. Units to be placed in reserve shutdown or retired from service with expected date of shutdown or retirement and an economic analysis supporting the planned retirement or shutdown dates vii. Units with specific plans for life extension, refurbishment, fuel conversion, modification or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, expected return to service date, capacity rating upon return to service, a general description of work to be performed as well as an economic analysis supporting such plans for existing units viii. Major capital improvements such as the addition of scrubbers, shall be evaluated through the IRP analysis to assess whether such improvements are cost justified when compared to other alternatives, including retirement and replacement of such resources ix. Other changes to existing generating units that are expected to increase or decrease generation capability of such units.	**Chapter 3.1** Supply-Side Generating Resources **Appendix 3B-1** Existing Generation Units in Service **Appendix 3B-10** Potential Unit Retirements **Appendix 3B-11** Planned Changes to Existing Generation Units
Guideline (F)(2)(b)	b. Assessment of Supply-side Resources. Include the current overall assessment of existing and potential traditional and alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent IRP or annual report.	**Chapter 3** Producing Cleaner Energy While Ensuring Reliability
Guideline (F)(2)(b)(i)	i. For the currently operational or potential future supply-side energy resources included, provide information on the capacity and energy available or projected to be available from the resource and associated costs. The utility shall also provide this information for any actual or potential supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.	**Chapter 3.8** The Five-Year Reliability Plan **Appendix 3C-3** Renewable Resources for VCEA with EPA **Appendix 3C-4** Potential Supply-Side Resources for VCEA with EPA **Appendix 3C-5** Summer Capacity Position for VCEA with EPA **Appendix 3C-6** Capacity Position for VCEA with EPA **Appendix 3C-7** Construction Forecast
Guideline (F)(2)(b)(ii)	ii. For supply-side energy resources evaluated but rejected, a description of the resource; the potential capacity and energy associated with the resource; estimated costs and the reasons for the rejection of the resource.	**Chapter 3.7** Future Supply-Side Resource Options
Guideline (F)(2)(c)	c. Planned Generation Additions. A list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition: i. Type of conventional or alternative facility and fuel(s) used ii. Type of unit (e .g . baseload, intermediate, peaking) iii. Location of each planned unit, including description of locational benefits identified by PJM and/or the utility iv. Expected Commercial Operation Date v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW)) vi. Summaries of the analyses supporting such new generation additions, including its type of fuel and designation as base, intermediate, or peaking capacity vii. Estimated cost of planned unit additions to compare with demand-side options	**Chapter 3** Producing Cleaner Energy While Ensuring Reliability **Appendix 3C-1** Generation under Construction **Appendix 3C-2** Planned Generation under Development **Appendix 3K-1** Comparison of Per MWh Costs of Selected Resources
Guideline (F)(2)(d)	d. Non-Utility Generation. A separate list of all non-utility electric generating facilities included in the IRP, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and contractual capacity (including any contract dispatch conditions or limitations), and the contractual start and expiration dates. The utility shall also indicate which facilities are included in their total supply of resources	**Section 5.1.3** Power Purchase Agreements **Appendix 5B** Other Generation Units
Guideline (F)(3)	3. Capacity Position. Provide a narrative discussion and tabulation reflecting the capacity position of the utility in relation to satisfying PJM's load obligation, similar to Schedule 16 of the attached schedules.	**Chapter 3.1** Supply-Side Generating Resources **Appendix 3C-5** Summer Capacity Position for VCEA with EPA **Appendix 5C** Capacity, Energy, and RECs for the Primary Portfolios
Guideline (F)(4)	4. Wholesale Contracts for the Purchase and Sale of Power. A list of firm wholesale purchased power and sales contracts reflected in the plan, including the primary fuel type, designation as base, intermediate, or peaking capacity, contract capacity, location, commencement and expiration dates, and volume.	**Appendix 2B-11** Wholesale Power Sales Contracts

Order / Guideline	Requirement	2024 IRP Section
Guideline (F)(5)	5. Demand-side Options. Provide the results of its overall assessment of existing and potential demand-side option programs, including a descriptive summary of each analysis performed or used by the utility in its assessment and any changes to the methods and assumptions employed since its last IRP. Such descriptive summary, and corresponding schedules, shall clearly identify the total impact of each DSM program.	**Chapter 3.2.5** Energy Efficiency and Demand Response as Resources to Manage Customer Load **Appendix 3D** Demand-Side Management **Appendix 2B-12** Load Duration Curves **Appendix 3E** Description of Active DSM Programs **Appendix 3F** Description of Proposed Programs **Appendix 3I** Projected Savings Attributable to DSM Programs by 2029 **Appendix 3K-1** Comparison of Per MWh Costs of Selected Resources
Guideline (F)(6)	6. Evaluation of Resource Options. Provide a description and a summary of the results of the utility's analyses of potential resource options and combinations of resource options performed by it pursuant to these guidelines to determine its integrated resource plan. IRP filings should identify and include forecasted transmission interconnection and enhancement costs associated with specific resources evaluated in conjunction with the analysis of resource options.	**Chapter 3.7** Future Supply-Side Resource Options **Appendix 2E** Renewable Energy Interconnection and Integration Costs
Guideline (F)(7)	7. Comparative Costs of Options. Provide detailed information on levelized busbar costs, annual revenue requirements or equivalent methodology for various supply-side options and demand-side options to permit comparison of such resources on equitable footing. Such data should be tabulated and at a minimum, reflect the resource's heat rate, variable and fixed operating maintenance costs, expected service life, overnight construction costs, fixed charged rate, and the basis of escalation for each component.	**Appendix 3K-1** Levelized Busbar Costs / Levelized Cost of Energy **Appendix 3K-2** Tabular Results of Busbar **Appendix 3K-3** Busbar Assumptions
Schedule 1	Peak load and energy forecast	**Appendix 2B-8** Projected Summer & Winter Peak Load & Energy Forecast for VCEA with EPA
Schedule 2	Generation output	**Appendix 3B-7** Energy Generation by Type for VCEA with EPA
Schedule 3	System output mix	**Appendix 3B-9** Energy Generation by Type (%) for VCEA with EPA
Schedule 4	Seasonal capability	**Appendix 3C-6** Capacity Position for VCEA with EPA
Schedule 5	Seasonal load	**Appendix 2B-10** Summer and Winter Peak
Schedule 6	Reserve margin	**Appendix 2B-9** Required Reserve Margin (for VCEA with EPA)
Schedule 7	Installed capacity	**Appendix 3B-6** Existing Capacity for VCEA with EPA
Schedule 8	Equivalent availability factor	**Appendix 3B-3** Equivalent Availability Factor for VCEA with EPA
Schedule 9	Net capacity factor	**Appendix 3B-4** Net Capacity Factor
Schedule 10	Average heat rate	**Appendix 3B-5** Heat Rates
Schedule 11	Renewable resources	**Appendix 3C-3** Renewable Resources for VCEA with EPA
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Order / Guideline	Requirement	2024 IRP Section
Schedule 15	Planned unit performance data	**Appendix 3C-1** Generation under Construction **Appendix 3C-2** Planned Generation under Development **Appendix 3C-4** Potential Supply-Side Resources for VCEA with EPA
Schedule 16	Utility capacity position	**Appendix 3C-5** Summer Capacity Position for VCEA with EPA
Schedule 17	Construction forecast	**Appendix 3C-7** Construction Forecast
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Case No. PUR-2023-00142 Final Order at 4	Continue to monitor new and developing energy storage technologies and refine its assumptions in future RPS plan and IRP proceedings	**Chapter 3.2.4** Energy Storage **Chapter 3.7** Future Supply-Side Resource Options
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	**Chapter 5** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years
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** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 years **Appendix 5C** Capacity, Energy, and RECs for the Primary Portfolios
Case No. PUR-2020-00035 Final Order at 12	We direct the Company to continue to model energy efficiency targets after 2025	**Appendix 2A** Load Forecast Methodologies
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** Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years
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** Virginia Bill Analysis **Appendix 4A** Virginia Bill Analysis

Order / Guideline	Requirement	2024 IRP Section
Case No. PUR-2018-00065 Final Order at 11	In future IRPs, the Company shall: 2. Continue to use the PJM load forecast, reduced by the energy efficiency spending requirement of Senate Bill 966 (Enactment Clause 15), both as an energy reduction and a supply resource, and separately identify the load associated with data centers.	**Chapter 2.1** Load Forecast **Appendix 2A** Load Forecast Methodologies
Case No. PUR-2018-00065 Final Order at 11	In future IRPs, the Company shall: 3. Model battery storage using the most updated cost estimates available.	**Chapter 3.2.4** Energy Storage **Chapter 3.7** Future Supply-Side Resource Options **Appendix 5B** Cost Assumptions
Case No. PUR-2018-00065 Final Order at 11	In future IRPs, the Company shall: 4. Model compliance with the Regional Greenhouse Gas Initiative.	**Chapter 5.3** Sensitivity Analyses **Appendix 5B** Cost Assumptions
Case No. PUR-2018-00065 Final Order at 11 Case No. PUR-2018-00065 Dec. 2018 Order at 5, n. 14	In future IRPs, the Company shall: 5. Model gas transportation costs, including a reasonable estimate of fuel transportation costs (firm and interruptible transportation, if applicable) associated with all natural gas generation facilities as well as fuel commodity costs, consistent with the December 2018 Order	**Appendix 5B** Cost Assumptions
Case No. PUR-2018-00065 Final Order at 11-12 Case No. PUR-2018-00065 Order on Reconsideration at 5	In future IRPs, the Company shall: 7. Model future solar PV tracking resources using two alternative capacity factor values: (a) the actual capacity performance of Dominion's Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and (The Commission additionally noted that for the 2020 IRP, the Company should use the three-year average of calendar years 2017-2019. For those solar tracking facilities that have not been in service for three years, the Company should use the historic data that is available.) (b) 25%. In the Order on Reconsideration, the Commission approved the Company's request to run one of the capacity factors contained in Directive #7 as a sensitivity; however, if the Company chooses to do so, it shall model the actual capacity performance of Dominion's Company-owned solar tracking fleet as the baseline assumption and use 25% as the sensitivity.	**Chapter 3.2.1** Solar Facilities
Case No. PUR-2018-00065 Final Order at 12	In future IRPs, the Company shall: 8. Systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects (Code § 56-599 B 10). For identified grid transformation projects, the Company shall include: (a) A detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) Detailed cost estimates of each proposed investment; (c) The benefits associated with each proposed investment; and (d) Alternatives considered for each proposed investment.	**Chapter 3.3** Distribution Grid Transformation **Appendix 3L** Distribution **Appendix 3M** Grid Transformation Plan
Case No. PUR-2018-00065 Final Order at 12, n. 49	In future IRPs, the Company shall: 9. Provide a schedule identifying the Company's contribution towards meeting the 5,000 MW target identified in Code § 56-585.1:4, including (a) a list of each project in service or under construction; (b) the nameplate capacity of each project; (c) the actual or projected in-service date; (d) whether the project is Company-build or a third-party PPA; and (e) the cost recovery mechanism (e.g., fuel, base rates, RAC, ring-fence arrangement, etc.) The Company shall also maintain this information on an on-going basis and provide it to Staff upon request.	**Appendix 3B-8** Solar and Wind Generating Facilities
Case No. PUR-2018-00065 Final Order at 12	In future IRPs, the Company shall: 10. Provide, in addition to a list of planned transmission projects, the projected cost per transmission project and indicate whether or not each project is subject to PJM's Regional Transmission Expansion Planning process.	**Appendix 2C-2** List of Planned Transmission Projects during the Planning Period
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.	**2024 IRP** Reference Index
Case No. PUE-2015-00035 Final Order at 10	The Commission directs the Company to: continue to investigate the feasibility and cost of extending the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2	**Chapter 3.5.1** Nuclear License Extensions
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	In future IRP filings, Dominion shall: include a more detailed analysis of market alternatives, especially third-party purchases that may provide long-term price stability, and includes, but is not limited to, wind and solar resources	**Chapter 2.2** Changes to the PJM Market Affect the Planning Environment **Chapter 3.1.2** Power Purchase Agreements **Appendix 5B** Cost Assumptions
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	In future IRP filings, Dominion shall: examine wind and solar purchases at prices (including prices available through long-term purchase power agreements) and in quantities that are being seen in the market at the time the Company prepares its IRP filings	**Chapter 2.2** Changes to the PJM Market Affect the Planning Environment **Chapter 3.1.2** Power Purchase Agreements **Appendix 5B** Cost Assumptions

Order / Guideline	Requirement	2024 IRP Section
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	In future IRP filings, Dominion shall: provide a comparison of the cost of purchasing power from wind and solar resources from third-party vendors versus self-build options, including off-shore and on-shore wind, with this comparison including information from a variety of third-party vendors	**Chapter 2.2** Changes to the PJM Market Affect the Planning Environment **Chapter 3.1.2** Power Purchase Agreements **Appendix 5B** Cost Assumptions
Case No. PUE-2015-00035 Final Order at 17	In future IRPs, Dominion shall: develop a plan for identifying, quantifying, and mitigating cost and integration issues associated with greater reliance on solar photovoltaic generation	**Appendix 2E** Renewable Energy Interconnection and Integration Costs
Case No. PUE-2013-00088 Final Order at 4	Next, we find that in future IRP filings, the Company shall provide further analysis related to the construction of North Anna 3 and the future of Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2, all of which have licenses that are scheduled to expire within the next thirty years.	**Chapter 3.5** Nuclear
Case No. PUE-2013-00088 Final Order at 5-6	The Company shall also provide status updates on any discussions it engages in with the United States Nuclear Regulatory Commission on a possible extension for the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2, in its future IRP and IRP update filings.	**Chapter 3.5.1** Nuclear License Extensions
Case No. PUE-2013-00088 Final Order at 8	Next, the Commission finds that in future IRP filings, Dominion Virginia Power should compare the cost of its demand-side management proposals to the cost of new generating resource alternatives. Specifically, Staff has suggested that it would be informative to compare the Company's expected demand-side management costs per megawatt hour saved to its expected supply side costs per megawatt hour. We agree and direct the Company to evaluate demand-side management alternatives using this methodology.	**Appendix 3K-1** Comparison of Per MWh Costs of Selected Resources
Case No. PUE-2013-00088 Final Order at 8	Further, we direct Dominion Virginia Power to include a broad band of prices used in future forecasting assumptions, such as forecasting assumptions related to fuel prices, effluent prices, market prices and renewable energy credit costs, in order to continue to set reasonable boundaries around the modeling assumptions, and to continue to refine the specific assumptions and sensitivity adjustments of its modeling data in future IRP filings.	**Chapter 5.3** Sensitivity Analyses **Appendix 5B** Cost Assumptions

NOTICE TO THE PUBLIC
OF A FILING BY VIRGINIA ELECTRIC AND POWER COMPANY
OF ITS INTEGRATED RESOURCE PLAN
CASE NO. PUR-2024-00184

On October 15, 2024, Virginia Electric and Power Company (the "Company"), submitted to the State Corporation Commission ("Commission") its 2024 Integrated Resource Plan (the "2024 IRP") pursuant to § 56-597 *et seq*. of the Code of Virginia ("Va. Code"). An integrated resource plan, as defined by Va. Code § 56-597, is "a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility." Pursuant to Va. Code § 56-599 D, the Commission will analyze the Company's 2024 IRP and make a determination as to whether the 2024 IRP is reasonable and in the public interest.

On [**date**], the Commission entered an Order for Notice and Comment ("Procedural Order") that, among other things, directed the Company to provide notice to the public and offered interested persons an opportunity to comment or request a hearing on the Company's 2024 IRP.

An electronic copy of the Company's 2024 IRP may be obtained, at no charge, by requesting it in writing from Nicole M. Allaband, Esquire, McGuireWoods LLP, Gateway Plaza, 800 East Canal Street, Richmond, Virginia 23219, or nallaband@mcguirewoods.com. If acceptable to the requesting party, the Company may provide the documents by electronic means. Interested persons may also download unofficial copies of the 2024 IRP and other documents from the Commission's website: http://www.scc.virginia.gov/case.

On or before [**date**], interested persons may file written comments concerning the issues in this case with Bernard Logan, Clerk, State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118. Interested persons desiring to submit comments electronically may do so by following the instructions found on the Commission's website: http://www.scc.virginia.gov/case. Comments shall refer to Case No. PUR-2024-00184.

On or before [**date**], interested persons may request that the Commission convene a hearing on the Company's 2024 IRP by filing a request for a hearing with the Clerk of the Commission at the address set forth above. Requests for hearing must include: (i) a precise statement of the filing party's interest in the proceeding; (ii) a statement of the specific action sought to the extent then known; (iii) a statement of the legal basis for such action; and (iv) a precise statement why a hearing should be conducted in this matter.

Any interested person may participate as a respondent in this proceeding by filing a notice of participation on or before [**date**]. Such notice of participation shall include the email addresses of such parties and their counsel. The respondent simultaneously shall serve a copy of the notice of participation on counsel to the Company. Pursuant to 5 VAC 5-20-80, *Participation as a respondent*, of the Commission's Rules of Practice and Procedure ("Rules of Practice"), any notice of participation shall set forth: (i) a precise statement of the interest of the respondent; (ii) a statement of the specific action sought to the extent known; and (iii) the factual and legal basis for the action. Any organization, corporation, or government body participating as a respondent must be represented by counsel as required by Rule 5 VAC 5-20-30, *Counsel*, of the Rules of Practice. All filings shall refer to Case No. PUR-2024-00184. For additional information about participation as a respondent, any person or entity should obtain a copy of the Commission's Procedural Order.

The Commission's Rules of Practice may be viewed at http://www.virginia.gov/case. A printed copy of the Commission's Rules of Practice and an official copy of the Commission's Procedural Order in this proceeding may be obtained from the Clerk of the Commission at the address set forth above.

VIRGINIA ELECTRIC AND POWER COMPANY

Virginia Electric and Power Company's Report of Its 2024 Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Case No. PUR-2024-00184
Docket No. E-100, Sub 204

Filed: October 15, 2024

Dominion Energy®

VIRGINIA ELECTRIC
AND POWER COMPANY

2024 Integrated Resource Plan

Case No. PUR-2024-00184
Docket No. E-100, Sub 204
Filed October 15, 2024

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[1] Filed in Virginia only.
[2] Filed in North Carolina only.

List of Acronyms

Acronym	Meaning
2024 IRP	2024 Integrated Resource Plan
AI	Artificial Intelligence
BGE	Baltimore Gas and Electric
BRA	Base Residual Auction
CAGR	Compound Annual Growth Rate
CC	Combined-Cycle
CCS	Carbon Capture and Sequestration
CIR	Capacity Injection Rights
CLOA	Construction Letter of Authorization
CO_2	Carbon Dioxide
Company	Virginia Electric and Power Company
CPCN	Certificate of Public Convenience and Necessity
CT	Combustion Turbine
CVOW	Coastal Virginia Offshore Wind
CVOW Project	CVOW Commercial Project
DAC	Direct Air Capture
DER	Distributed Energy Resource
Dominion Energy	Dominion Energy, Inc.
DOM LSE	Dominion Energy Load Serving Entity
DOM Zone	Dominion Energy Zone
DSM	Demand-Side Management
EFORd	Equivalent Forced Outage Rate Demand
EIA	U.S. Energy Information Administration
EJ	Environmental Justice
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitations Guidelines
EPA	U.S. Environmental Protection Agency
ESA	Electric Service Agreements
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FRR	Fixed Resource Requirement
GET	Grid Enhancing Technologies
GHG	Greenhouse Gas
Gross CONE	Gross Cost of New Energy
GTSA	Grid Transformation and Security Act of 2018
GW	Gigawatts
GWh	Gigawatt Hours
ICF	ICF Resources, LLC
IDP	Integrated Distribution Planning

Acronym	Meaning
IRP	Integrated Resource Plan
kV	Kilovolts
kWh	Kilowatt Hours
LDES	Long Duration Energy Storage
LNG	Liquefied Natural Gas
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MW	Megawatts
MWh	Megawatt Hour
NC Public Staff	North Carolina Utilities Commission Public Staff
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
NOVEC	Northern Virginia Electric Cooperative
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
ODEC	Old Dominion Electric Cooperative
PJM	PJM Interconnection, L.L.C.
Planning Period	15-year Period of 2025 to 2039
PPA	Power Purchase Agreement
REC	Renewable Energy Certificate(s)
RFP	Request for Proposal
Roadmap	IDP Roadmap
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SCC	Virginia State Corporation Commission
SELOA	Substation Engineering Letters of Authorization
SMR	Small Modular Reactor
Stakeholder Process	2024 Dominion Energy Virginia and North Carolina Integrated Resource Plan Stakeholder Process
SUP	Strategic Underground Program
V2G	Vehicle-to-grid
Va. Code	Code of Virginia
VCEA	Virginia Clean Economy Act of 2020
VEJA	Virginia Environmental Justice Act

Meeting the Need for Reliable, Affordable, and Increasingly Clean Energy

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 2.7 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina.

Our mission is to provide the reliable, affordable, and increasingly clean energy that powers our customers every day. Dominion Energy has a proven track record of operating its generation, transmission, and distribution systems reliably, with our customers having uninterrupted power 99.98% of the time. Our rates have remained consistently below the national average (currently more than 14 percent below the national average) and have increased less than the general rate of inflation since 2007. And the Company is a nationally recognized leader in the development and operation of renewable and carbon-free offshore wind, solar, energy storage, and nuclear energy technology.

We are constructing the largest offshore wind farm in the United States. We are expanding our solar portfolio—already the largest solar portfolio in PJM Interconnection, LLC ("PJM")—our 13-state regional transmission organization. We have been a leading nuclear operator for more than half a century and operate the only four nuclear units in the nation licensed for 80 years. We remain committed to transitioning to a cleaner energy future, consistent with state and federal public policy directives, in a manner that does not compromise reliability or affordability.

Looking forward, the need for additional in-state resources to generate, transmit, and distribute power reliably is acute, consistent with the previous integrated resource plan ("IRP"). Demand is forecasted to increase 5.5% annually over the next decade and double by 2039 in the Company's delivery zone within PJM. Dominion Energy has an obligation to serve this demand. Doing so will require 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. As required by the Code of Virginia ("Va. Code") § 56-599, energy independence along with rate stability, economic development, and service reliability must be considered in every IRP.

This 2024 IRP focuses heavily on reliance on utility resources, recognizing the limits on the ability to import power from elsewhere in PJM. An over-reliance on imported power creates reliability and price risks for our customers, particularly as conventional generation resources have retired and will continue to retire across PJM for economic and environmental compliance reasons. Energy security has arguably never been more important for the well-being of the communities that we serve.

Against that backdrop, the 2024 IRP presents multiple potential portfolios (the "Portfolios") the Company could take to meet our customers' capacity and energy needs over the next 15 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 IRP is a "snapshot in time" and not a request to approve any specific resource or Portfolio.

However, it is apparent under any reasonable set of planning assumptions that maintaining reliability and affordability will require an "all of the above" approach that includes continued focus on energy efficiency programs, an expanded and improved transmission and distribution grid, and more of all available generation resources—wind (primarily offshore), solar, natural gas and nuclear, along with energy storage. The Company must maintain a focus on a diverse portfolio of energy supply resources, and that will include investment not only in planned renewable and energy storage resources but also traditional dispatchable generation and new technologies.

Two dynamics within PJM since the last IRP filing—both related to reliability concerns—have underscored the need for additional power generation and electric transmission resources within the Company's delivery zone, as well as the value of generation resources which can produce energy at times of peak need.

First, PJM holds annual capacity auctions 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. 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 most recent capacity auction in July 2024 yielded the highest capacity price ever for the Dominion Energy Zone ("DOM Zone"), which has the highest forecasted load growth of any area within PJM. The price within the DOM Zone was 65 percent higher than the price for PJM generally, and more than 15 times the prior year's clearing price for the rest of PJM.

Second, to recognize the contribution of different resources to reliability, PJM adopted an approach called "effective load carrying capability" ("ELCC"), which the Federal Energy Regulatory Commission ("FERC") approved in January 2024. This method allows PJM to measure how much capacity may be provided by different generation resources at different times. In general, a resource that contributes a significant level of capacity during historically high-risk hours (*i.e.*, hours with very high electricity demand and low resource output) will have a higher capacity value than a resource that delivers the same capacity during historically low-risk hours. This decision reflects lessons learned from, among other things, Winter Storm Elliott, where all-time winter peaks occurred on Christmas Eve 2022 during the early morning hours when renewable resources were not available.

The ELCC methodology results in significant discounting of the capacity value of resources that cannot produce electricity upon demand (such as intermittent resources dependent on the sun or the wind) and assigning relatively higher values to resources that can run on demand—otherwise known as dispatchable resources—which include nuclear and natural gas units. This shift further supports the proposition that serving our customers reliably requires a balanced and effective mix of resources, and not over-reliance on any single generation technology or category.

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 specific actions the Company must take in implementing this process.[1] For the 2024 Dominion Energy Virginia and North Carolina Integrated Resource Plan Stakeholder Process ("Stakeholder Process"), we retained the expertise of professional third-party facilitators to ensure this process is conducted efficiently, fairly, and effectively. In doing so, the Company has created a website (devirp.dominionenergy.com) dedicated to the Stakeholder Process (see Appendix 1 for details of the Stakeholder Process).

The Stakeholder Process over the past year consisted of four phases: (1) a kick-off meeting that provided all stakeholders with a foundation of knowledge on the IRP; (2) small group meetings where stakeholders had candid conversations with the facilitators; (3) topic-specific workshops for more in-depth conversations; and (4) summary meetings before the filing to review the collective input and recommendations of stakeholders incorporated into the IRP, and after the filing for an overview of final information.

In sum, the 2024 IRP highlights the need to address significant demand growth through resource adequacy across all functions of the utility, the balance between clean energy priorities and the paramount requirement of service reliability, and maintaining rates that continue to be affordable for our customers to support a vibrant economy for Virginia and North Carolina. Dominion Energy remains confident, with the ongoing support of policy makers, regulators, and other stakeholders, in its ability to continue to successfully deliver on all of these mission elements.

[1] Va. Code § 56-599 D.

The Integrated Resource Plan

The purpose of an IRP is to show pathways that the Company could take to reliably meet our customers' energy needs over the next 15 years. This 2024 IRP is meant for use as a long-term planning document based on a "snapshot in time" of current technologies, market information, and projections. IRPs are not a request to approve any specific resource or Portfolio but rather to assess their reasonableness for long-term planning purposes.

In this 2024 IRP, the Company presents four primary resource Portfolios to meet customers' needs in the future under different scenarios, which are designed using constraint-based least-cost planning techniques and proven technologies. The Portfolios provide potential pathways to meeting customers' energy and capacity needs while transitioning to a cleaner energy future and at the same time maintaining reliability and affordability. The Portfolios evaluate the impacts of the Virginia Clean Economy Act of 2020 ("VCEA") and new federal environmental rules impacting carbon-emitting generation units. Given uncertainty in technological development and changing laws over an extended 15-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.

Dominion Energy files this 2024 IRP with the Virginia State Corporation Commission ("SCC") in accordance with Va. Code § 56-597 *et seq.* and the SCC's guidelines issued on December 23, 2008, in Case No. PUE-2008-00099. The Company also files this 2024 IRP with the North Carolina Utilities Commission ("NCUC") in accordance with §§ 62-2 and 62-110.1(c) of the North Carolina General Statutes and Rule R8-60 of NCUC's Rules and Regulations. The 2024 IRP also addresses requirements identified by the SCC and NCUC in prior relevant orders, as well as current and pending provisions of state and federal law and regulation.

Stakeholder Process Highlight: During the Stakeholder Process, the Company received feedback from stakeholders regarding all aspects of the IRP, both quantitative and qualitative. The Company carefully considered all feedback and questions received, and incorporated them into the 2024 IRP where possible, while taking into consideration complex modeling constraints, the need for complete data, and operational and regulatory requirements. Appendix 1 includes a Stakeholder Process Report.

Chapter 1. Commitment to Reliability

We have an obligation to serve: As a regulated public 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 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. As a vertically integrated utility, 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 supply-side portfolio consists of 20,131 megawatts ("MW") of generation capacity, including approximately 1,277 MW of resources owned by third parties from which the Company purchases the output through power purchase agreements ("PPAs"). The Company's demand-side management ("DSM") portfolio consists of energy efficiency and demand response programs in Virginia and North Carolina.

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). 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, as well as more than 1,000 substations. The DOM Zone is part of PJM,[2] 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

[2] 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.

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.

Dominion Energy also owns approximately 60,000 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia and North Carolina. Distribution lines bring power from substations to individual neighborhoods, homes, and businesses.

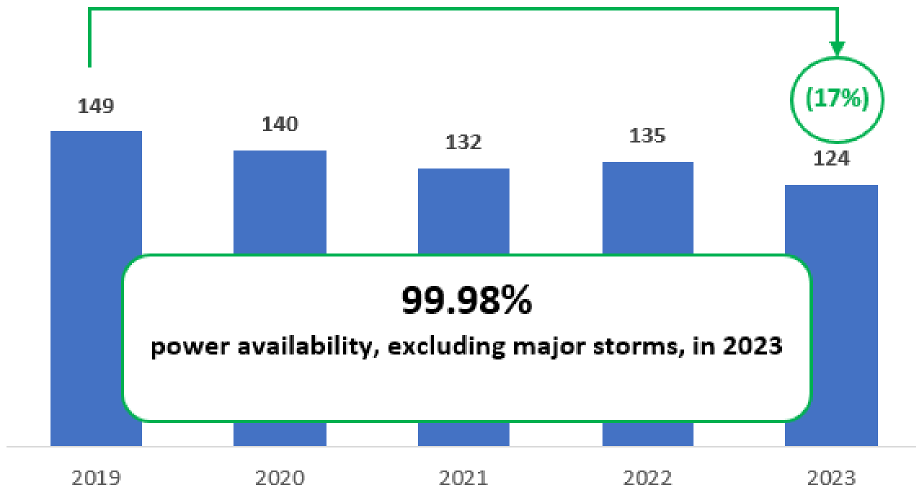
Power generation is the process of creating electricity from a primary source of energy, whether nuclear, natural gas, coal, solar, wind, or water. For power generation, reliability requires a sufficient number of generation resources and resource diversity to avoid over-reliance on any one energy source, 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[3] ("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") 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.

[3] NERC was created in 1968 in the aftermath of the Northeast Blackout of 1965.

Figure 1.1: SAIDI in Dominion Energy's Service Territory (minutes)



Dominion Energy serves 2.5 million residential customers and approximately 200,000 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 of this 2024 IRP, 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 and electrification of energy needs, especially transportation, which has historically been met primarily by fossil fuels.

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 grid transformation.

2.1 The Load Forecast

Dominion Energy develops load forecasts to determine customers' future energy and capacity needs and to plan to meet those needs. The 2024 IRP presents two load forecasts: 1) the 2024 PJM Derived Load Forecast and 2) the 2024 Company Load Forecast. At the SCC's directive, the Company used the 2024 PJM Derived Load Forecast in the development of all Portfolios. Details on the methodologies used to develop the PJM Derived Load Forecast and the Company Load Forecast, including the data center forecast, electric vehicle ("EV") forecast, energy efficiency adjustment, and retail choice adjustment, are provided in Appendix 2A. Additional data underlying the load forecasts is presented in Appendix 2B.

The PJM Derived Load Forecast continues to grow over the next 15 years

Figure 2.1.1 presents the 2024 PJM Derived Load Forecast for coincident peak[4] for the DOM Zone. Overall, the 15-year compound annual growth rate ("CAGR")[5] for the DOM Zone is 4.8%. The figure separates out the DOM LSE and non-DOM LSE portions ("Residual DOM Zone) of the DOM Zone zonal coincident peak. This highlights the differences in the growth expected by these two parts of the DOM Zone.

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[4] 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 load serving entity ("LSE").
[5] CAGR is the average growth rate, in this case growth in load, over a period of time.

Figure 2.1.1: 2024 PJM Derived Load Forecast for Coincident Peak for the DOM Zone

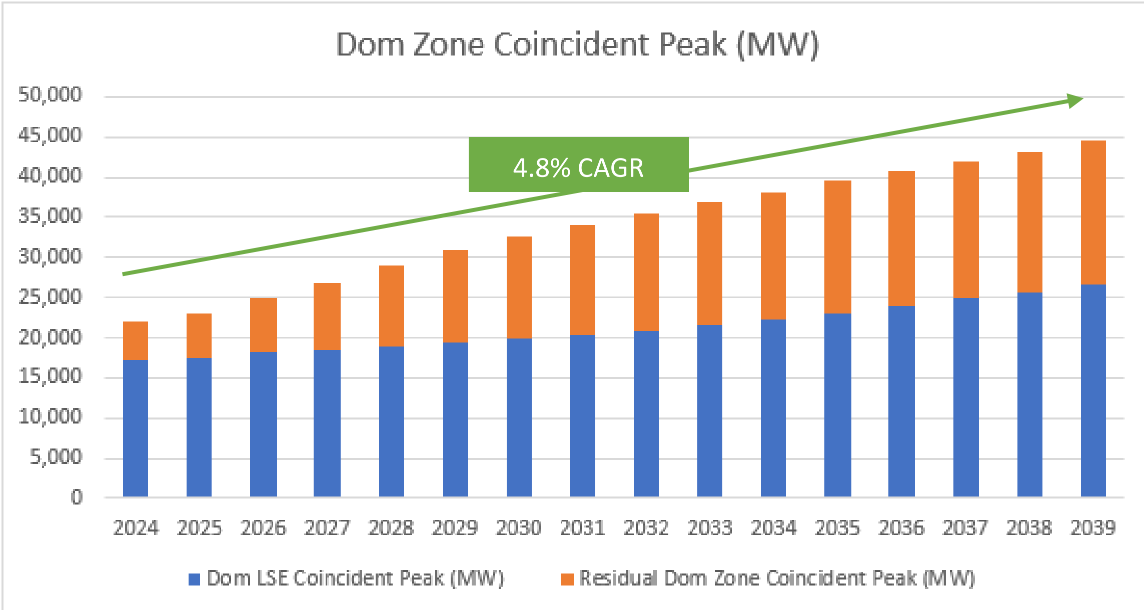
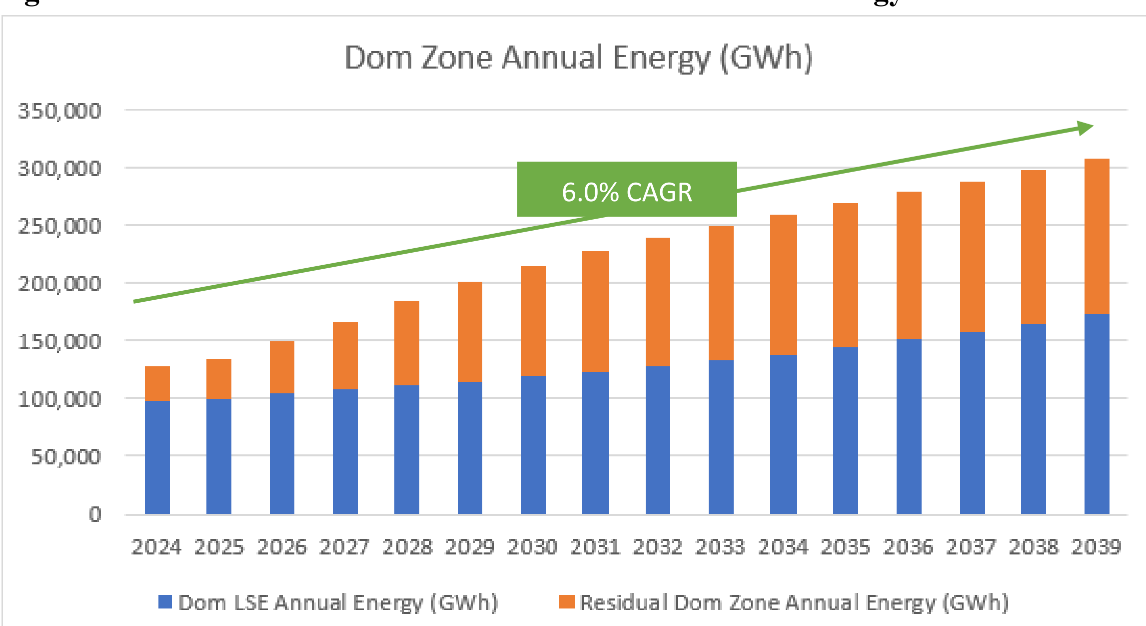


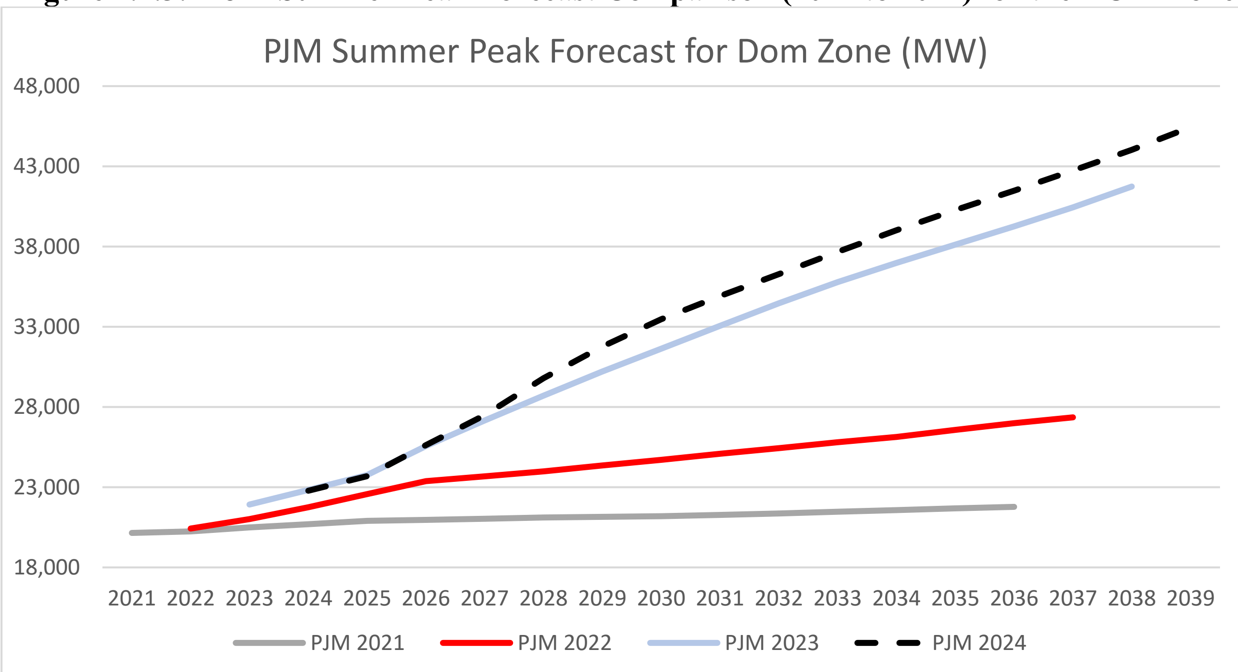
Figure 2.1.2 presents the 2024 PJM Derived Load Forecast for energy demand for the DOM Zone. Overall, the 15-year CAGR for the DOM Zone is 6.0%. The figure separates out the DOM LSE and the Residual DOM Zone portions of the zonal energy demand. This highlights the differences in the growth expected by these two parts of the DOM Zone. It is important to note that Dominion Energy is the transmission provider throughout the DOM Zone, not just for its own retail customers.

Figure 2.1.2: 2024 PJM Derived Load Forecast for Annual Energy for the DOM Zone



PJM's 2024 Load Forecast for the DOM Zone increased for the fourth year in a row relative to the prior year's forecast, as can be seen in Figure 2.1.3. Key drivers to the year-over-year change in the PJM DOM Zone Load Forecast include: 1) increases in data center load growth focused in the NOVEC and ODEC service territories, and 2) revisions to the PJM EV load projections.

Figure 2.1.3: PJM Summer Peak Forecast Comparison (2021 to 2024) for the DOM Zone



The DOM Zone's peak demand is growing faster than all other PJM zones

Dominion Energy's peak loads have been increasing each year and the load forecast predicts peak loads will continue to grow. Looking further into the growth components, Figure 2.1.4 below shows the average annual growth in the summer peak demand for various PJM load zones by key drivers.[6] The DOM Zone is forecasted to grow faster than any other PJM zone. Growth in DSM and distributed solar sufficiently offsets the increases in summer peak demand associated with economic expansion. However, the increase in demand associated with EVs and data centers (captured in the "Adjustments" category in Figure 2.1.4) far exceeds these DSM and distributed solar offsets.

[6] In Figure 2.1.4, DOM Zone is referred to as VEPCO.

Figure 2.1.4: PJM Summer Peak Average Annual Growth (2024 to 2039)[7]

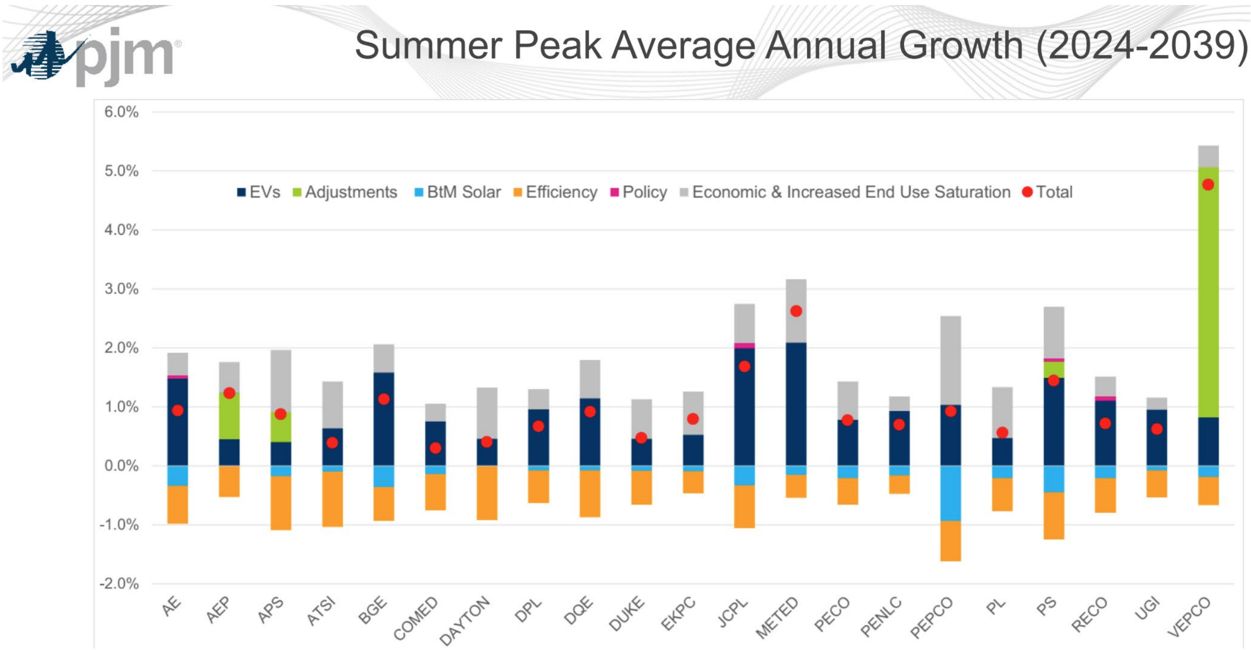
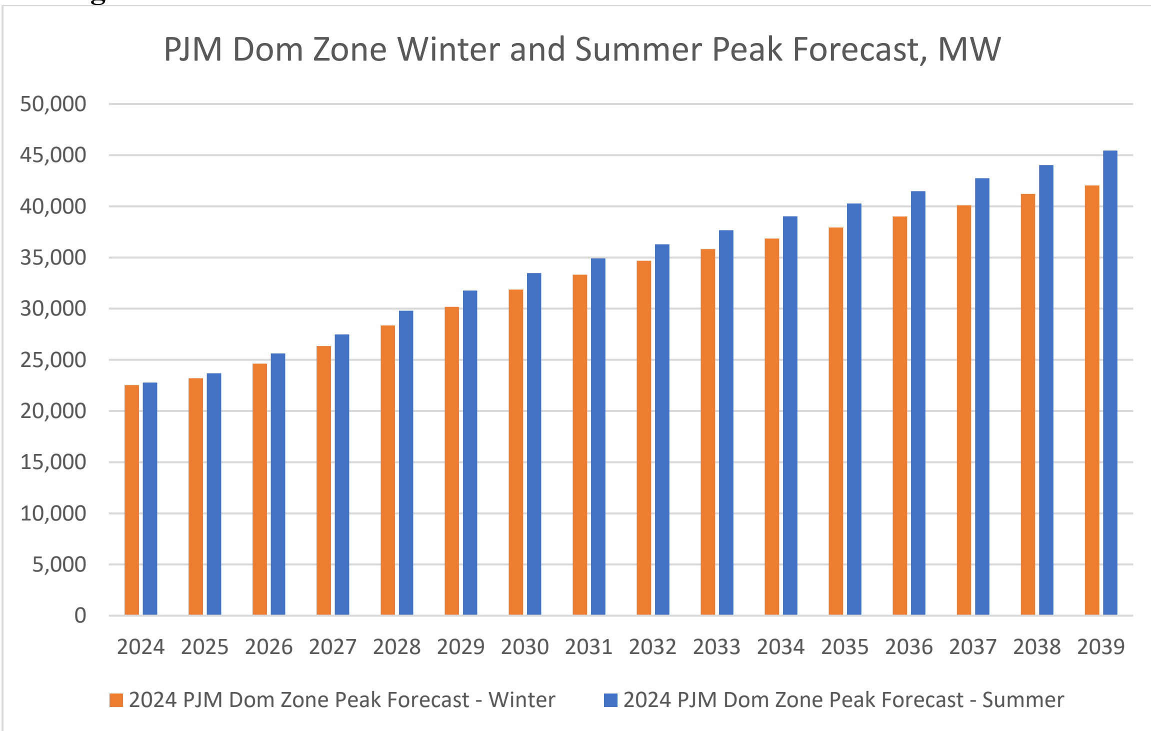


Figure 2.1.5 shows the PJM DOM Zone winter and summer forecasted peaks. Over the 15-year forecast horizon, winter and summer peaks are projected to grow by 4.2% and 4.7%, respectively, on a compound annual basis. Forecasted peaks assume normal weather, meaning that extreme weather events could cause actual peaks to greatly exceed the forecast in any given year and for sustained periods. It is important to emphasize here that a utility system must be designed for extreme weather events, not just normal weather. See Chapter 5.4 for additional discussion of extreme weather.

7 https://www.pjm.com/-/media/committees-groups/committees/pc/2023/20231205/20231205-item-06---2024-preliminary-pjm-load-forecast.ashx.

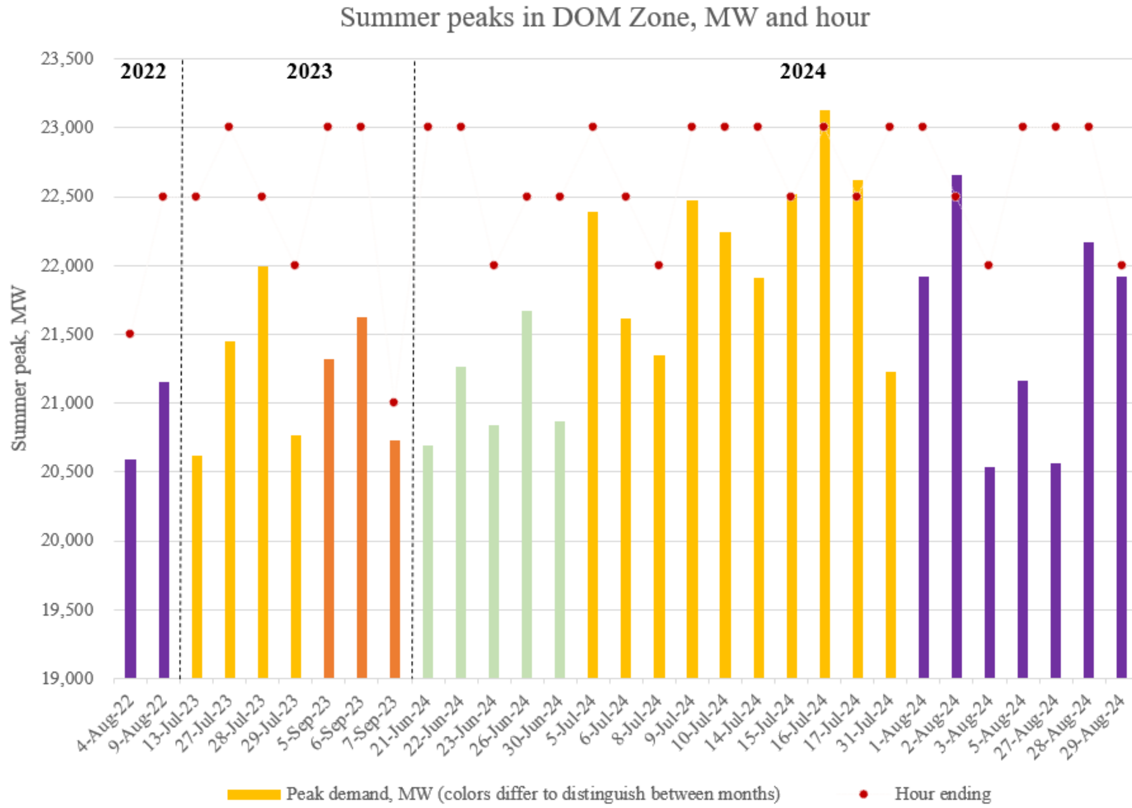
Figure 2.1.5: PJM DOM Zone Winter and Summer Peak Demand Forecast[8]



In addition to increasing demand, changes in load shape (*i.e.,* the shifts in timing of higher and lower energy usage during the day) could increase reliability risks. For instance, the high demand during the late afternoon or early evening associated with the charging of EVs, combined with air conditioners trying to keep up with the high temperatures, and the decrease in solar output with the setting sun, could pose challenges to reliability, especially during very hot days. Indeed, PJM identified July hours ending 18 and 19 (*i.e.*, 5:00-7:00 pm) as the riskiest hours for loss of load in summer. Over the last two years, system peaks in the DOM Zone have been occurring in winter mornings and summer evenings, when renewable output is less available. Moreover, the top 30 all-time summer peaks in the DOM Zone have all been set since 2022, 15 of which were set in hour ending 18 (see Figure 2.1.6 below). A diverse portfolio of resources will be needed to ensure the Company can meet customers' needs at all hours of the day, including peaks when renewable output may not be available.

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

Figure 2.1.6: Highest summer peaks in the DOM Zone in 2022 to 2024



Electrification and data centers are two of the key drivers of load growth in the DOM Zone and DOM LSE

Economic growth, electrification (mostly with EVs), and accelerating data center expansion are driving the most significant demand growth in the Company's history and they show no signs of abating.

The transportation industry is actively continuing its shift toward electrification of personal vehicles, fleets, and mass transit. EV adoption will continue to contribute to growth in electric demand. Separate from this 2024 IRP, the Company will be filing a Transportation Electrification Plan by February 3, 2025, as directed by the SCC in Case No. PUR-2020-00151.

Dominion Energy serves the largest data center market in the world, larger than the next five biggest U.S. data center markets combined. Data centers are large block load customers. Since 2013, the Company has averaged around 15 data center connections (*i.e.*, data center campuses) per year. In 2023, the Company connected 15 data center campuses with an ultimate capacity of 933 MW. The Company has connected 14 new data center campuses in 2024 as of August, with an ultimate capacity of 949 MWs. The Company expects to connect two additional data center campuses by the end of the year, for a total of 16 new data center campus connects, with an ultimate capacity of almost 1 gigawatt ("GW") in 2024, which is equivalent to approximately 100 million

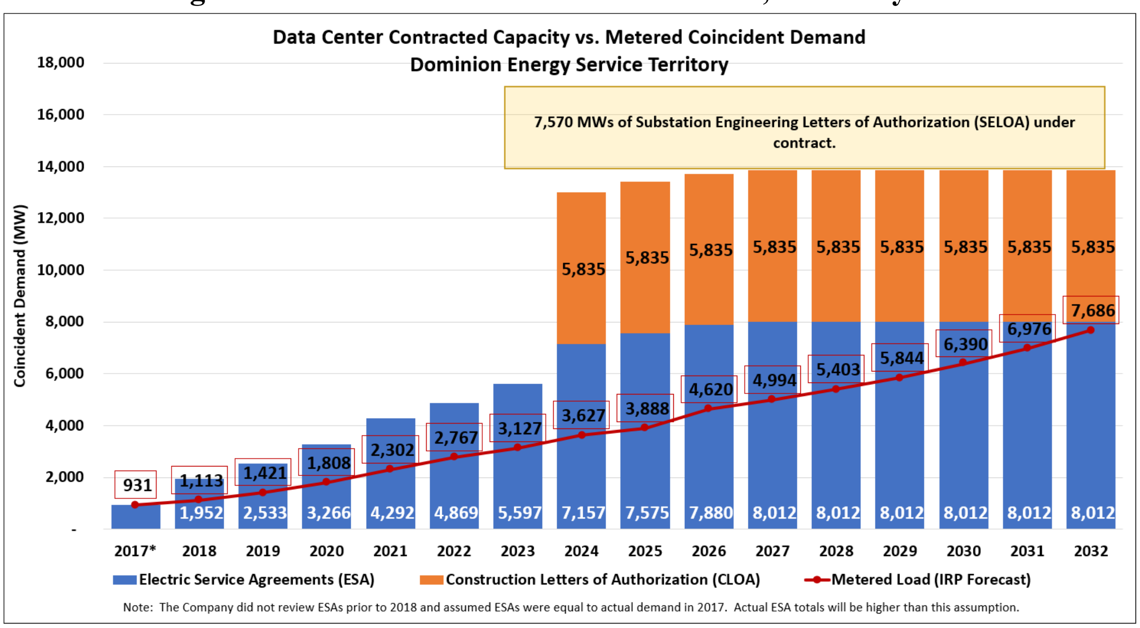
LED bulbs.[9] The big drivers of current and future growth include migration to the cloud as businesses outsource information technology functions, smartphone technology and apps, 5G technology, digitization of data, and artificial intelligence ("AI"). From storing videos to hosting AI systems that allow consumers to create documents, web pages, music, and more, data centers serve the needs of the public every day.

Dominion Energy is confident in its Data Center Load Forecast. The Company uses a combination of historical metered data along with forward-looking customer intelligence, derived from long-term relationships with customers, to develop its Data Center Load Forecast. The Company provides a DOM LSE 15-year data center load forecast to PJM, who independently reviews and verifies before incorporating it into PJM's own forecast.

Dominion Energy's Data Center Load Forecast is informed and validated by existing contracts with customers. As projects progress, customers enter into a series of contracts with binding financial commitments. Dominion Energy regularly reviews this contractual approach to ensure that its Data Center Load Forecast reflects projects that will come to fruition.

Figure 2.1.7 illustrates customer contracts executed as of July 2024. These contracts are broken into (i) Substation Engineering Letters of Authorization ("SELOA"), (ii) Construction Letters of Authorization ("CLOA"), and (iii) Electric Service Agreements ("ESA"). As a customer moves from (i) to (iii), the cost commitment and obligation by the customer increases.

Figure 2.1.7: Customer Contracts Executed, as of July 2024



[9] Based on typical performance, a light-emitting diode A19 lamp is roughly 92 lumens per watt and consumes about 10 watts.

As shown above, in Figure 2.1.7, the Company is currently studying 7,570 MW of data center demand within the SELOAs stage, which means a customer has requested the Company to begin the necessary engineering for new distribution and substation infrastructure required to serve the customer. There are also 5,835 MW of data center demand that have executed CLOAs, which are contracts that enable construction of the required distribution and substation electric infrastructure to begin. Should a customer in this stage elect to discontinue a project, they are obligated to reimburse the Company for its investment to date. Finally, the 8,012 MW included in ESAs represent contracts for electric service between Dominion Energy and a customer. Each contract is structured for an individual account. By signing an ESA, the customer is committing to consuming a certain level of electricity annually – often with ramp schedules where the contracted MW grow over time.

These contracted amounts do not contemplate the many data center projects that are in a development phase and have not yet reached a point in the service connection process where a contract is executed. The ESA contracts in hand already support the 2024 IRP load forecast through 2032, if not beyond.

There are 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 and custom savings programs, lighting, HVAC and other energy efficiency products. Dominion Energy continues to explore opportunities for and interest in demand response programs with its largest customers.

Also of note, data centers contribute to the economic development in the areas that they are located. Not only do they contribute to local, state, and federal tax revenues, but they also directly and indirectly influence employment.

2.2 Changes to the PJM Market Affect the Planning Environment

Dominion Energy participates in the PJM capacity planning process and capacity auctions to ensure supply of capacity resources for its customer load. As a member of PJM, the Company has the option to participate in the capacity market either (i) through the reliability pricing model ("RPM") forward capacity market, or (ii) through the fixed resource requirement ("FRR") alternative.

The FRR alternative allows LSEs in PJM to cover the capacity load in their service area through their own generation or bilateral capacity transactions.[10] The RPM is PJM's resource adequacy construct. The purpose of the RPM is to develop a long-term pricing signal for capacity resources and LSE obligations that is consistent with the PJM RTEP process. RPM adds stability and a locational nature to the pricing signal for capacity. Under the RPM model, utilities participate in

[10] A bilateral capacity transaction is an agreement between two parties where one party sells/transfers capacity rights to a second party to allow the second party to use the capacity rights to meet their own capacity obligations.

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.

As more fully described below, Dominion Energy has traditionally participated in the RPM capacity market. In 2021, for the 2022/2023 Delivery Year (*i.e.*, planning year), the Company elected the FRR alternative. On May 2, 2024, the Company announced its intention to leave the FRR alternative and return to RPM, as of the 2025/2026 Delivery Year, due to changes to the capacity rules that rendered this decision in the best interest of the Company's customers.

2.2.1 Short-Term Capacity Planning

As a member of PJM, Dominion Energy is a signatory to PJM's Reliability Assurance Agreement, 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[11] 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, 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.

Currently, for the 2024/2025 delivery year, the Company offers its capacity resources, including owned and contracted generation, into its FRR Plan as a generation provider. In other words, in operating under the FRR alternative, the Company would self-supply its capacity obligation. As an LSE, the Company is obligated to provide sufficient generation to cover its load obligation. The load obligation is calculated using PJM's most current load forecast and planning parameters such as equivalent forced outage rate demand ("EFORd"),[12] ELCC, and reserve margin requirements.

Beginning June 1, 2025, the Company will return to the RPM capacity market. Importantly for modeling purposes, the modeling is indifferent to whether the Company satisfies its capacity obligation through the RPM auction or through the FRR alternative because the Company models the forecasted reserve margin at the minimum reserve margin in either case.

2.2.2 Long-Term Capacity Planning

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

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

[12] 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.

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 2025/2026 delivery year assumptions for the 2025 calendar year in this 2024 IRP because it represents the expected peak load during the summer of 2025.

The Company makes one assumption when applying the PJM reserve margin to its modeling efforts. Since PJM uses a shorter planning period than the Company (*i.e.*, ten years for PJM rather than 15 years for this 2024 IRP), 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.*, 2039).

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. 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.

In February 2023, PJM reported that its New Services Queue consisted primarily of renewables (94%) and gas (6%), and not all of these projects are expected to be constructed. PJM found that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth in the foreseeable future. The completion rate (from queue to steel in the ground) would have to increase significantly to maintain required reserve margins.

For the first time in recent history, PJM could face decreasing reserve margins should these trends continue. The PJM study found that at current low rates of renewable entry, consistent with its Low New Entry scenario, the projected reserve margin would be 15%. The projected total capacity from generating resources would not meet projected peak loads. By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%, as projected demand response may be insufficient to cover peak demand expectations.

Even if new resource entry progresses as projected in the High New Entry scenario, it is still crucial to maintain needed existing resources, as well as quickly incentivize and integrate new entry. Integration of significant amounts of additional resources envisioned to meet this demand will be challenging, and therefore addressing issues such as resource capacity accreditation is critical in the near term.

2.2.3 PJM Capacity Market Reform Lowered ELCC Values for Most Generating Resources

In addition to the challenges to new entry and reduced reserve margins, in 2024, PJM updated the ELCCs values for renewable and energy storage resources and gave dispatchable resources ELCCs for the first time. Most resources, particularly renewable resources and shorter duration (*i.e.*, 4 hour) energy storage saw a significant decrease in value.

According to PJM, the capacity value of each resource type is influenced by load shape, resource profile shape and variance, resource limitations, amount of resources and compatibility with other resources. As defined by PJM, ELCC is a measure of the additional load that a particular generator of interest can supply without a change in reliability. The metric of reliability used by PJM is loss-of-load expectation, a probabilistic metric that is driven by the timing of high loss-of-load probability hours. Therefore, PJM states that a resource that contributes a significant level of capacity during high-risk hours (hours during which PJM expects the peak demand to occur) will have a higher capacity value (*i.e.*, a higher ELCC) than a resource that delivers the same capacity only during low-risk hours.

For the purposes of the 2024 IRP, the Company used the PJM ELCC studies published in March and April of 2024 to estimate the capacity value of generation and energy storage resources. PJM provides values for a 10-year period (through delivery year 2034/2035). Beyond that time period, the Company used projected ELCC values from ICF Resources, LLC ("ICF").

A comparison of the ELCC values for the resources from the 2023 IRP to the latest 2024 study is below in Figure 2.2.3.1. Not only do the 2024 study results show a significant and immediate decline in value for most renewable and energy storage resources, but the study showed that ELCCs for these resources will decline even further between 2025 and 2035. This means, in terms of capacity value, significantly more renewable and energy storage resources would be needed to replace a single traditional dispatchable resource. The decline in ELCC value coupled with the existing challenges to bring new resources online means that existing and future dispatchable resources are needed to ensure continued reliability.

Figure 2.2.3.1: Comparison of ELCC Values by Resource Type

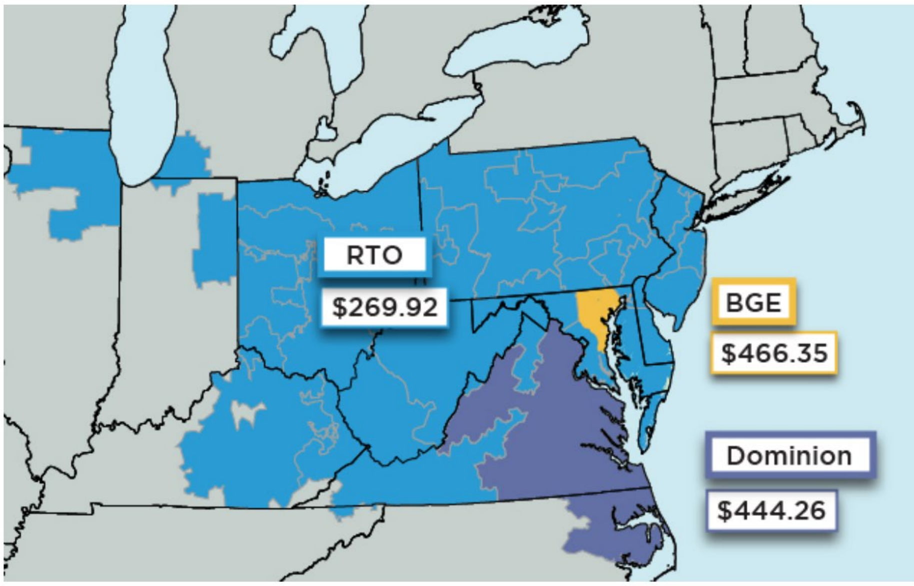
Selected Resources	2023 IRP Value	PJM ELCC Ratings (2025/2026 vs. 2034/2035 Delivery Year)
Fixed-Tilt Solar	37%	9% declining to 3%
Tracking Solar	55%	14% declining to 4%
4-hr Storage	82%	59% declining to 38%
Offshore Wind	43%	60% declining to 20%
Nuclear	PJM calculated capacity value using the EFORd methodology prior to 2024.	95% declining to 93%
Gas CC		79% increasing to 82%
Gas CT		62% increasing to 78%

2.2.4 The 2025/2026 PJM BRA Results

On July 30, 2024, PJM published the results of the BRA for the 2025/2026 Delivery Year (see Figure 2.2.4.1). The results showed a significant increase in auction prices across PJM. Two zones that are modeled separately, the Baltimore Gas and Electric ("BGE") zone in Maryland and the

DOM Zone, had even higher prices. The key drivers for the higher auction prices are a decrease in supply due to generation retirements, load growth in PJM, and the new ELCC rating methodology. The clearing price from the BRA for the DOM Zone was $444.26/MW-Day which is over 60% higher than the Regional Transmission Organization ("RTO") clearing price of $269.92 and 15 times higher than the previous 2024/2025 RTO clearing price of $28.92/MW-Day. This clearing price shows that there was insufficient capacity offered into the BRA resulting in a DOM Zone clearing price equal to the Gross Cost of New Entry ("Gross CONE")[13] price cap.

Figure 2.2.4.1: PJM 2025/2026 RPM Capacity Auction Results - Capacity Prices[14]



Elevated capacity prices at the RTO and DOM Zone affirm 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.

2.2.5 Limited Energy and Capacity Availability in the PJM Market Increase Risks Associated with Market Exposure

As required by Va. Code § 56-599, energy independence along with rate stability, economic development, and service reliability must be considered in every IRP.

PJM is responsible for finding the least cost means of satisfying demand while meeting the reliability requirements, and dispatches power generators within the entire RTO accordingly. Dominion Energy works with PJM to satisfy its LSE requirements through load procurement in the PJM market. The Company also coordinates with PJM on power generation in the operational

[13] Gross CONE is the total amount of annual revenue that a new generation resource would need to recover its capital investment and other costs over its economic life.
[14] https://www.pjm.com/-/media/about-pjm/newsroom/2024-releases/20240730-pjm-capacity-auction-procures-sufficient-resources-to-meet-rto-reliability-requirement.ashx.

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.

Over the last decade, the Company has depended upon market power purchases for an increasing share of total energy served. In 2021, the Company purchased 14% of its total energy served from the PJM market, in 2022 that number increased to 21%, and in 2023 that number increased again to 22%.

While market purchases have been, and will continue to be, part of meeting customers' needs, overdependence on market purchases could be cause for concern. Power may not be available for purchase when it is needed, for example during extreme weather events or other demand spikes. This risk is expected to be exacerbated in the future in light of the new environmental regulations described in Chapter 5.1 and Appendix 5A, the PJM capacity market reform, and other states' energy policies. While the Company will still continue to utilize the PJM energy and capacity markets to provide energy and capacity as needed to meet the Company's load requirements, resource adequacy is a vital issue that must be addressed at the state level.

Hourly energy availability depends on sufficiency of generation capacity in the Company's fleet, as well as energy import capability within the PJM footprint and within the entire Eastern Interconnection.

Based on a series of PJM reports[15] analyzing potential impacts of integration of renewable resources, further discussed in Chapter 2.4.2, maintaining reliability of electric service is becoming more challenging as dispatchable generators retire. Reserves are declining, which means that generating capacity available to PJM for dispatch exceeds projected demand by a smaller margin than it used to. This safety cushion is essential for reliability. Limited availability of capacity could lead to load shed.

Capacity availability and reliability (*i.e.*, generator class ELCC ratings based on performance in extreme load events) also affects its pricing, which in turn affects electric bills. Had there been more generating capacity available within the DOM Zone for the 2025/2026 capacity auction, capacity prices within DOM Zone could have cleared at a lower price. However, due to generation capacity scarcity, the DOM Zone was modeled separately, as discussed in Chapter 2.2.4.

[15] *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.

Improvements in the transmission system 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.

As required by Virginia Code § 56-599, energy independence along with rate stability, economic development, and service reliability must be considered in every IRP. 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.

The recent increase in load is expected to continue, as reflected in the most recent PJM Load Forecast as discussed in Chapter 2.1. To avoid overreliance on the energy and capacity market and consider energy independence, the Company is developing and building generating capacity, as discussed in Chapters 3.2, 3.5, and 3.6.

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 of our 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 and operates 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.

The Company's transmission system is designed and operated to ensure adequate and reliable service to customers while meeting all regulatory requirements and standards. Specifically, the

Company's transmission system is developed to comply with NERC Reliability Standards, as well as the Southeastern Reliability Corporation Supplements to the NERC Reliability Standards. The federally mandated NERC Reliability Standards constitute the minimum criteria with which all public utilities must comply as components of the interstate electric transmission system. Moreover, the Energy Policy Act of 2005 mandates that electric utilities follow these NERC Reliability Standards and imposes significant fines for noncompliance.

The Company participates in numerous regional, inter-regional, and sub-regional studies to assess the reliability and adequacy of the interconnected transmission system. Since Dominion Energy is a member of PJM, PJM is registered with NERC as the Company's planning coordinator and transmission planner. Accordingly, the Company participates in the PJM RTEP to develop the RTO-wide transmission plan for PJM.

The PJM RTEP is a FERC-approved annual transmission planning process that includes extensive analysis of the electric transmission system to determine any needed improvements or additional infrastructure to interconnect new generation and/or customers and ensure continued reliability. The PJM RTEP covers the entire PJM control area and includes projects proposed by PJM, as well as projects proposed by Dominion Energy and other PJM members through internal planning processes. The PJM RTEP process includes both a 5-year and a 15-year outlook.

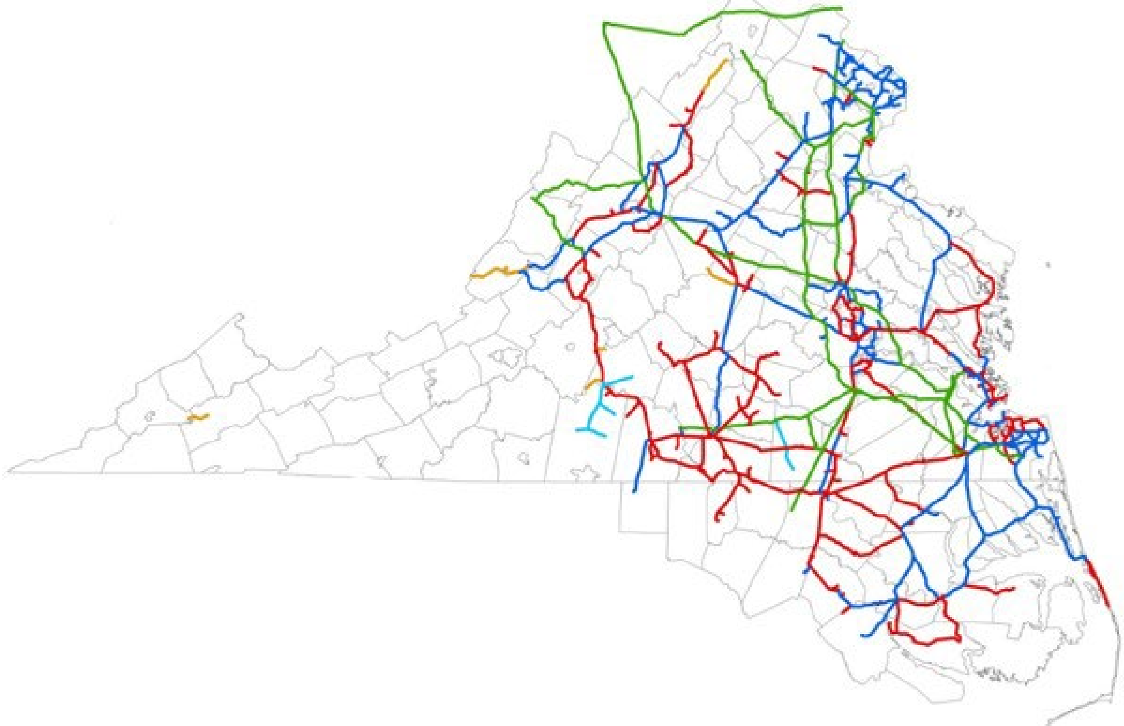
The Company also evaluates its ability to support expected customer growth through its internal transmission planning process. The results of these evaluations indicate if any transmission improvements are needed, which the Company includes in the PJM RTEP process as appropriate. The Company then seeks approval for the transmission improvements from the appropriate regulatory body.

Additionally, the Company performs seasonal operating studies to identify facilities in its transmission system that could be critical during the upcoming season. The Company coordinates with neighboring utilities to maintain adequate levels of transfer capability to facilitate economic and emergency power flows.

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. These facilities are 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



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

Through participation in the PJM RTEP as well as regional, inter-regional, and sub-regional studies described in Chapter 2.3.1, the Company annually assesses the reliability and adequacy of the interconnected transmission system to ensure the system is adequate to meet customers' electrical demands both in the near-term and long-term planning horizons. Based on proposals reviewed and approved by the PJM Board, the Company was awarded over 150 electric transmission projects totaling $2.5 billion in December 2023.

In addition to investing in new infrastructure, the Company is also working with PJM to find cost-effective ways to upgrade existing infrastructure on existing rights-of-way, in order to allow existing lines to carry more electricity (*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.

The Company is currently participating in PJM's latest Open Window,[16] which commenced on July 15, 2024, to identify additional infrastructure needs to accommodate load growth both in Virginia and beyond. The Company is working expeditiously with PJM, the SCC, local officials, and other stakeholders to fast-track critical projects to ensure continued reliability of the transmission system. The Company will continue to evaluate the transmission system and plan for the expected load growth.

For example, as announced in October 2024, Dominion Energy, American Electric Power, and FirstEnergy Corp. have entered into an innovative joint planning agreement to propose several new regional electric transmission projects across multiple states within the PJM footprint.

The companies jointly proposed the projects through PJM's RTEP Open Window process in September. The proposed projects include several new 765 kV, 500 kV and 345 kV transmission lines in Virginia, Ohio, and West Virginia. The projects remain in the early stages of development. If selected by PJM, the companies would then undertake an extensive, multi-year process to select routes, perform environmental studies, engage with communities, obtain state and local permitting and build the projects.

In addition to the joint proposals, each of the three companies have also submitted individual proposals for other transmission projects consistent with how each company has participated in past PJM open windows.

Stakeholder Process Highlight: Stakeholders provided qualitative feedback regarding reliability focused on GETs and advanced conductors. Including information on GETs in the 2024 IRP is based on stakeholder feedback.

The Company also continually assesses GETs as part of transmission planning. GETs consist of a group of technologies that offer a variety of benefits, such as managing congestion, increasing line utilization rates, and enhancing operational efficiency of the transmission grid. GETs include both software and hardware solutions. In the software arena, GETs have the capability to enhance control and protection systems, advanced sensing and metering tools, real-time contingency analysis tools, and artificial-intelligence assisted operator decision-making processes. Hardware solutions generally focus on improving physical assets and infrastructure used to carry, convert, or control electricity. A broad classification of GETs incorporates advanced technologies for cyber risk detection and encrypted substation communications, digital platforms for analysis of power quality issues, and automation tools to optimize outage planning. The groups of technologies that fall under a narrower classification of GETs include: dynamic line ratings,

[16] When needs are identified, PJM opens competitive planning "windows" so that transmission owners and other developers can submit solutions they've designed. If a solution is selected and approved by the PJM Board of Managers, the developer will seek siting approval for construction and maintenance of substations and transmission lines included in its proposal. PJM's competitive window planning process encourages submissions from a variety of sources and gives PJM the opportunity to assess creative and efficient regional transmission solutions.

dynamic transformer ratings, power flow controllers, and topology optimization. Further details on GETs is located in Appendix 2D.

2.3.3 Transmission System Reliability Analyses

Due to the projected increase in demand, the increasing penetration of renewable energy and energy storage resources, and the retirement of synchronous generators, the Company continues to conduct reliability analyses to study the impacts of these trends on the transmission system and to 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 2024 IRP: (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. A summary of the results of the Company's analysis is included below. Additional details regarding the types of analyses conducted are provided in Appendix 2D.

The import analysis found that the DOM Zone's import capability in 2028 ranges between 11,414 MW in winter peak, 11,788 MW in summer peak, and 13,136 MW in shoulder months. The higher import capability limits are due to additional transmission infrastructure under construction or under development, particularly projects in northern Virginia and an additional line that will interconnect Dominion Energy with First Energy. Although planned upgrades to the transmission system will support increased power imports to the DOM Zone, the analysis does not assess the *availability* of energy to import to the DOM Zone. Notably, given federal and state policies incentivizing or mandating the retirement of traditional dispatchable generation, and the increasing penetration of renewable energy resources, there may be less energy available to import to the DOM Zone when needed, especially during extreme weather events.

The inertial and frequency response analysis demonstrates that traditional synchronous generation resources provide inertia that slow down deviations in frequency in the electric system and help maintain system reliability. Inverter-based resources on the other hand operate differently and cannot currently supply the inertia to maintain a balanced grid. However, future technological advances may enable inverter-based resources to supply "virtual inertia" that will help ensure reliable operations. The Company is evaluating this technology as part of its Locks Microgrid project associated with its Grid Transformation Plan.

Similarly, traditional synchronous generation resources help in quickly detecting and responding to short-circuit events or faults. However, inverter-based resources do not provide significant fault current and the system's response to faults is becoming less predictable as the penetration of inverter-based resources increases. The analysis showed that in areas with high penetration of inverter-based resources, the system's short-circuit strength is deficient. The study recommends adding synchronous condensers or reducing the number of inverter-based resources.

The ability to restore power to the system without external support (*i.e.*, black start) is crucial for ensuring system reliability. Black start units must be dispatchable and provide predictable output, which is not possible for intermittent resources. As more intermittent resources are connected to the transmission and distribution grid, system restoration procedures must be re-evaluated and new technologies, such as grid-forming inverters, will need to be investigated. See Appendix 2D for more information on technologies the Company is investigating to support the transmission grid.

Although the two Portfolios (VCEA with EPA and VCEA without EPA) evaluated within the transmission study 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 ("CC") units and quick-start combustion turbines ("CTs"), 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.

2.4 Generation Considerations

2.4.1 Expanding Generation Resource Adequacy

Historically, the Company's transmission planning scope includes the entire DOM Zone, whereas the Company's generation planning scope focuses primarily on the DOM LSE. The tightening supply of energy and capacity and increasing demand for energy, 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 supply-side resources 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 energy potentially available to Dominion Energy for purchase from PJM to serve DOM LSE customers for planning purposes in this 2024 IRP, 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 2024 IRP is discussed in Chapter 5.2.

2.4.2 Development Challenges

There are challenges to the siting and development of new power generation resources across all technologies, including project interconnection, supply chain, labor shortages, and land use and permitting delays, to name a few. Specific to project interconnection, while PJM reform is well underway, the length of time for the interconnection study process and the costs of network upgrades or interconnection facilities under the current PJM process remain as development and construction challenges. Supply chain challenges include supply shortages due to increased demand, price increases, shipping delays, and regulatory and trade barriers that impact both 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, and energy storage projects, such as lithium, cobalt, and nickel, due to the rapid increase in demand driven primarily by the growth of EVs. Additionally, a growing need for skilled labor for manufacturing and installation of power generation systems and labor shortages more generally can slow project deployment and increase labor costs. Time associated with permitting approvals, and evolving land use requirements also pose challenges to construction timelines and cost.

Specific to project interconnection, while PJM reform is well underway, the length of time for the interconnection study process and the costs of network upgrades or interconnection facilities under the current PJM process remain as development and construction challenges. Potential mitigation of these challenges is underway with interconnection queue reform by PJM and FERC. In early 2021, PJM announced a pause in its generation queue study process and the start of a stakeholder process—the Interconnection Process Reform Task Force—due to a backlog of queue projects waiting on final interconnection service agreements. The task force developed a new interconnection queue analysis process to accommodate the integration of large numbers of renewable energy projects within the transmission system, which was approved by PJM's stakeholders in May 2022 and by FERC in November of 2022. Under the new process, all projects located on the same feeder are placed in and remain in one cluster for the reliability study and cost allocation analysis. Once implementation of the new process is complete, the new queue study process is projected to take less than 24 months from start to finish, which includes the execution of final generator interconnection agreement.

Separately, FERC issued a notice of proposed rulemaking in June 2022 to address significant backlogs in interconnection studies across the country. FERC proposed to implement a first-ready served queue cluster study process, improved interconnection queue processing speed, updated modeling and performance requirements for system reliability, technological advancements to the interconnection process, as well as development of a benchmarking planning case for extreme weather events. Queue reform, once fully implemented, is intended to accelerate viable projects through the queue to facilitate faster construction and commission.

Details regarding the Company's analysis of interconnection and integration costs, including transmission integration, generation re-dispatch, and regulating reserves costs, associated with renewable energy are included in Appendix 2E. The Company has updated its estimates for renewable energy integration costs compared to prior IRPs and continues to refine and assess the necessary grid modifications and associated costs of renewable energy integration.

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 in energy and capacity and result in increasing savings in power generation and emissions.

To meet the development targets of the VCEA for renewable and energy storage resources, 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 over the next decade and longer 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 SMRs, or LDES, 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.*, 2025 to 2029) 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 Fleet

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 2023 capacity resource mix by unit type.

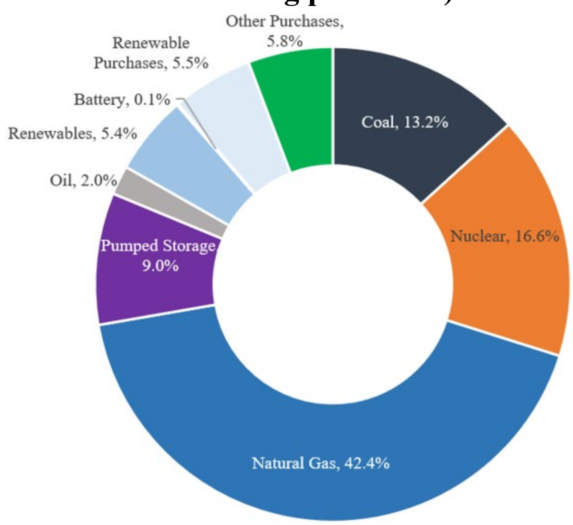
Figure 3.1.1.1: 2023 Capacity Resource Mix by Unit Type

Generation Resource Type	Number of Generating Units	Net Summer Capacity (MW)	Percentage of Net Summer Capacity
Nuclear	4	3,348	16.6%
Natural Gas	29	8,533	42.4%
Pumped Storage	6	1,808	9.0%
Coal	6	2,666	13.2%
Oil	21	400	2.0%
Renewable - solar, wind, hydro, biomass	27	1,087	5.4%
Energy Storage	1	20	0.1%
Renewable Purchases		1,109	5.5%
Other Purchases		1,160	5.8%
Total		**20,131**	**100.0%**

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

Due to differences in operating and fuel costs of various types of units and PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. PJM dispatches all generating and energy storage resources within the power pool in the PJM footprint, including the Company's generation fleet. PJM dispatches resources in the PJM power pool from the lowest cost units to the highest cost units, while maintaining its mandated reliability standards. The Company's electric customers receive the economic and reliability benefits of all resources in the PJM power pool regardless of the source. Figures 3.1.1.2. and 3.1.1.3 provide the Company's 2023 actual capacity and energy mix. Appendix 3A provides capacity-related information directed by the SCC.[17]

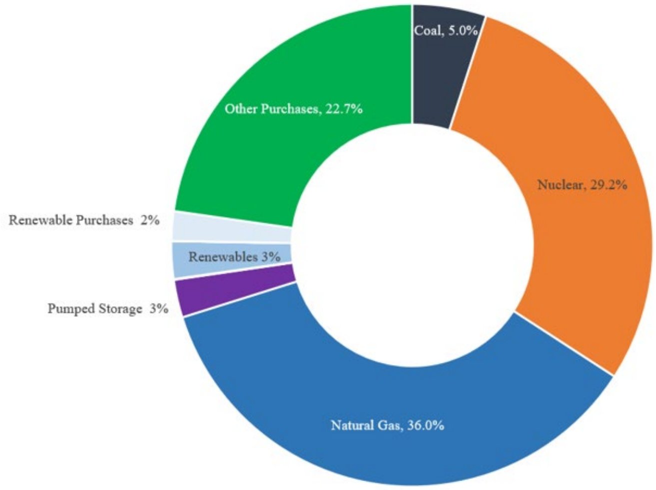
Figure 3.1.1.2: Capacity Mix (Summer Installed Capacity as of December 31, 2023, including purchases)



This represents *potentially available contribution* of each type of generating resource owned by the Company or procured through bilateral transactions (such as bundled PPAs).

[17] 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: 2023 Energy Mix



The energy mix chart shows the *sources of energy actually delivered* to the Company's customers in 2023. Although still relatively small, energy supplied by solar in 2023 was almost 5 times the contribution in 2022.

3.1.2 Power Purchase Agreements

Dominion Energy supplements its generation fleet with third-party PPAs. The Company has existing contracts with renewable energy and fossil based PPAs, for approximately 1,277 MW (nameplate capacity) as of the end of 2023.

During the past several years, the Company has increased its engagement of third-party solar and energy storage developers in both its Virginia and North Carolina service territories.

In Virginia, the Company issues annual request for proposals ("RFPs") for solar, onshore wind, and energy storage resources, and will continue to do so.

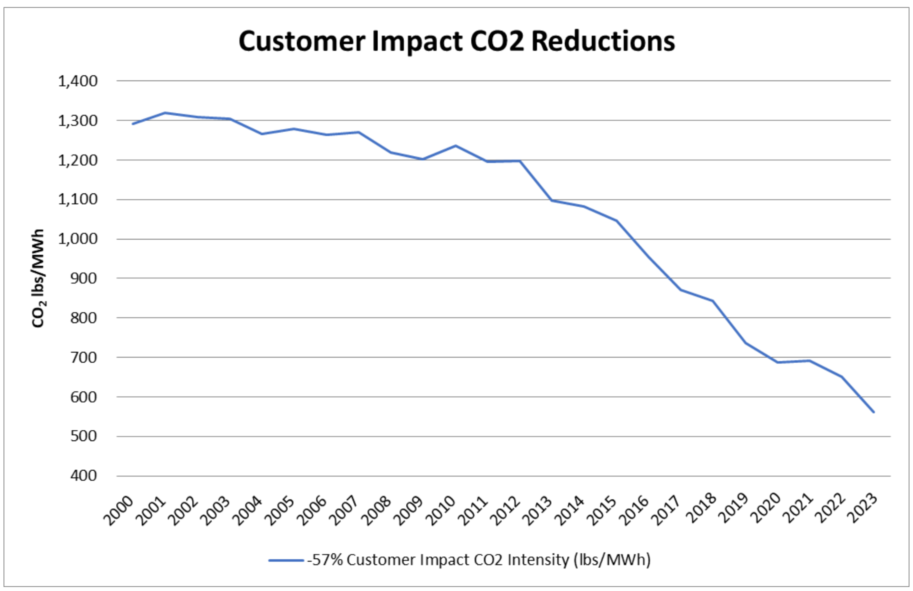
In North Carolina, the Company offers the avoided cost tariffs to qualifying facilities under the Public Utilities Regulatory Policies Act, to sell capacity and energy at the Company's published North Carolina Schedule 19 rates. The Company has 90 effective PPAs totaling approximately 692 MW (nameplate). Of this, 687 MW (nameplate) are from 89 solar facilities that were in operation as of the first quarter of 2024.

3.1.3 Company-Owned System Generation – Reduction in Emissions

> **Stakeholder Process Highlight**: During the Stakeholder Process, we received input to include information on carbon emissions. As a result, the Company included more information on carbon emissions and carbon intensity in the 2024 IRP.

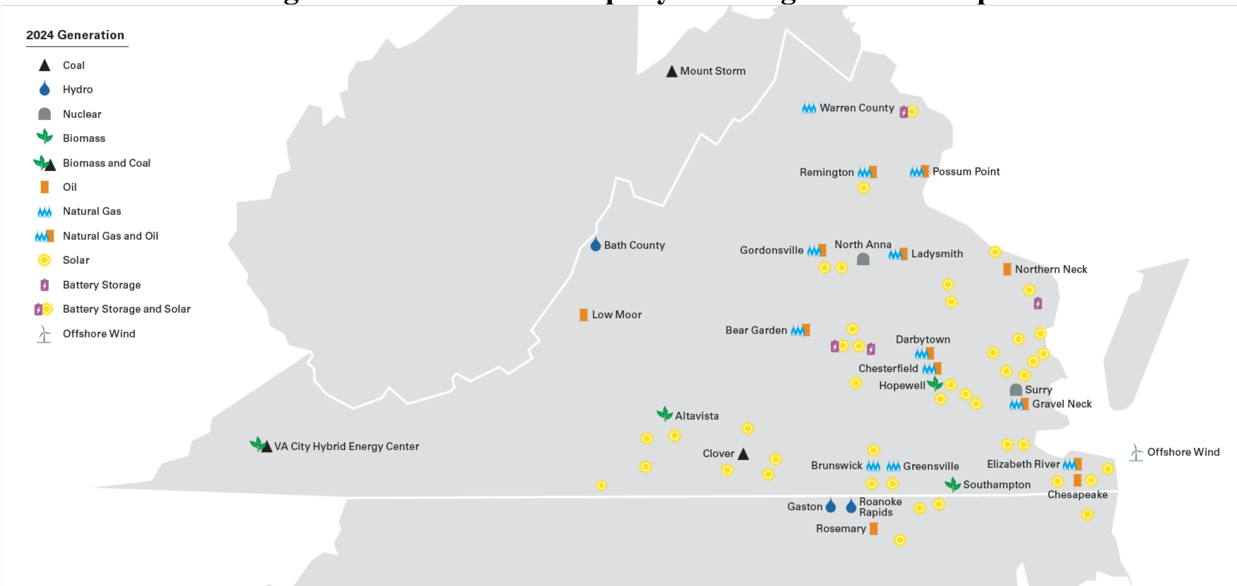
Over the past two decades, the Company has made changes to its generation mix that have significantly improved environmental performance. These changes include the retirement of certain units, the conversion of certain units to cleaner fuels, and the addition of air pollution controls. This integrated 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 3.1.3.1, customer impact CO_2 intensity has decreased by 57% since 2000.

Figure 3.1.3.1: Customer Impact CO_2 Intensity



Pursuant to the Grid Transformation and Security Act of 2018 ("GTSA") and the VCEA, the Company has made great strides in developing solar generation across Virginia. See Figure 3.1.3.2 below. Additional details regarding the Company's existing generation fleet as well as third-party PPAs are provided in Appendix 3B.

Figure 3.1.3.2: 2024 Company-owned generation map



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. 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 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.

3.2.1 Solar Facilities

Since the passage of the VCEA, Dominion Energy has petitioned for the SCC approval of 3,636 MW of Company-owned solar projects and solar PPAs in its annual Renewable Portfolio Standard ("RPS") Development Plan proceeding.[18] Most of these projects and PPAs have received SCC approval and are in the development, construction, or operation phase.

[18] The total amount of MW includes the projects that are being petitioned for concurrently with the filing of the 2024 IRP in the Company's 2024 RPS Development Plan proceeding in Case No. PUR-2024-00147.

In North Carolina, the Company has entered into PPAs totaling nearly 700 MW (nameplate) with qualifying facilities under the Public Utilities Regulatory Policies Act, as stated in Chapter 3.1.2.

3.2.2 Onshore Wind

Dominion Energy continues to evaluate onshore wind projects brought for its consideration through the annual RFP process. While the Company is interested in cost-effective onshore wind projects, the current availability of land suitable for onshore wind construction in Virginia and is, and likely will continue to be, a constraint.

3.2.3 Offshore Wind

In October 2020, a pilot for the Coastal Virginia Offshore Wind Commercial Project ("CVOW Project") consisting of two offshore wind energy turbines generating 6 MW each and located 27 miles off the coast of Virginia Beach went into operation.

In December 2022, Dominion Energy received SCC approval of the commercial portion of the CVOW Project, which represents nearly 2,600 MW of clean energy. It is proceeding on time and on budget and is expected to be in-service by the end of 2026.

In August 2024, Dominion Energy also secured the rights for a 176,505-acre lease area off the coast of Virginia Beach, adjacent and to the east of where the Company's CVOW Project is currently under construction. Winning the lease provides Dominion Energy with the option to pursue additional offshore wind development in the mid-Atlantic. The Bureau of Ocean Energy Management indicates the lease area could support between 2.1 GW and 4.0 GW of offshore wind energy generation. The lease area is located approximately 35 nautical miles from the mouth of the Chesapeake Bay.

The Company has also recently acquired a portion of an offshore wind lease for 38,964 acres off the coast of North Carolina, which will allow for development of an 800 MW offshore wind facility—enough to power 200,000 homes and businesses.

3.2.4 Energy Storage

There are four classifications of energy storage resources: chemical, thermal, mechanical, and electrochemical.

Dominion Energy has been operating the Bath County Pumped Storage Station since 1985. This facility, located in Bath County, Virginia, is one of the largest pumped storage hydroelectric power plants in the world. The expansion of renewable resources has caused us to research and deploy other types of energy storage resources onto our system.

In 2018, the GTSA established a pilot program allowing the Company to pilot 30 MW of electrochemical battery storage, and in 2020, the VCEA expanded on the GTSA by setting targets for the development of energy storage in Virginia. The Inflation Reduction Act further provided incremental incentives for energy storage projects.

To date, the SCC has approved the Company's development of 28.34 MW of the 30-megawatt pilot allowance in the GTSA. Three Lithium-ion Battery Energy Storage Systems are currently operational. Three other projects are comprised of three non-lithium batteries and one lithium-ion battery and are expected to reach commercialization by the end of 2027. The Company continues to evaluate additional opportunities for the remaining MW of the GTSA pilot program.

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. Additional information about the Company continuing to pilot long duration storage options is provided in Chapter 3.7.

In addition to these pilot projects, the Company solicits energy storage projects and PPAs in its annual RFPs and petitions the SCC for approval of the best projects in its annual RPS Development Plan proceeding.

3.2.5 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, save energy with smart technology and ENERGY STAR® Products, earn rewards for managing EV charging, and benefit from a home energy audit. 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.

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 1,306 gigawatt hours ("GWh") in 2024 and 2,500 GWh by 2029. From a demand perspective, DSM programs also reduce the summer capacity needs by 314 MW in 2024 and 553 MW by 2029. See Appendix 3D for additional information. Additional information about the Company's active programs, recently approved programs, and forecasted growth is included in Appendices 3E, 3F, and 3G, respectively. Projected program-by-program savings in 2029 are shown in Appendix 3I.

The analysis conducted by DNV GL Energy Insights U.S.A. comparing primary fuel sources for generation is provided in Appendix 3J. Appendix 3K compares the costs of the Company's DSM programs to the costs of supply-side resources on a levelized-cost-per-MWh basis.[19]

3.3 Distribution Grid Transformation

As society has grown more dependent on electricity, customers tolerance for outages has waned. The safe, reliable, and consistent grid connectivity has never been more important than it is today. Fundamental changes in the energy industry driven by the rise in DERs and expanding electrification have prompted the need for utilities across the country to modernize their distribution grids and transform how distribution grid planning occurs. As the distribution grid evolves to support a more dynamic energy system, the Company must continuously identify new scenarios and solutions to ensure safe and reliable service. Those solutions will likely include emerging technologies, such as a comprehensive distributed energy resource ("DER") management system, customer-owned assets leveraged for grid support as non-wires alternatives and grid hardening to support a more resilient distribution system. Regardless of which solutions are implemented, a robust and secure telecommunication infrastructure platform that provides real-time situational awareness and supports analysis and control of intelligent grid components will be essential for an adaptable and responsive distribution grid.

The proliferation of DERs is changing the way the distribution grid operates. DER output is highly variable which can lead to fluctuations in grid power quality and reliability. To serve all customers effectively, the Company must safeguard the distribution grid against challenges that arise when integrating DERs. While the Company invests in technologies to strengthen and provide greater visibility and control of the distribution grid, equipment is also needed from the developers of DERs to ensure that their interconnection does not compromise the safety or reliability of the distribution grid.

Appendix 3L provides an overview of the Company's distribution planning process and current initiatives related to the distribution grid, 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. Appendix 3M provides additional details on the projects and successes of the Grid Transformation Plan. Appendix 3N is the Company's current integrated distribution planning ("IDP") roadmap ("Roadmap"), which presents tangible goals for the components of IDP on which the Company plans to focus in the near term. Figure 3.3.1 provides a visual representation of the Roadmap.

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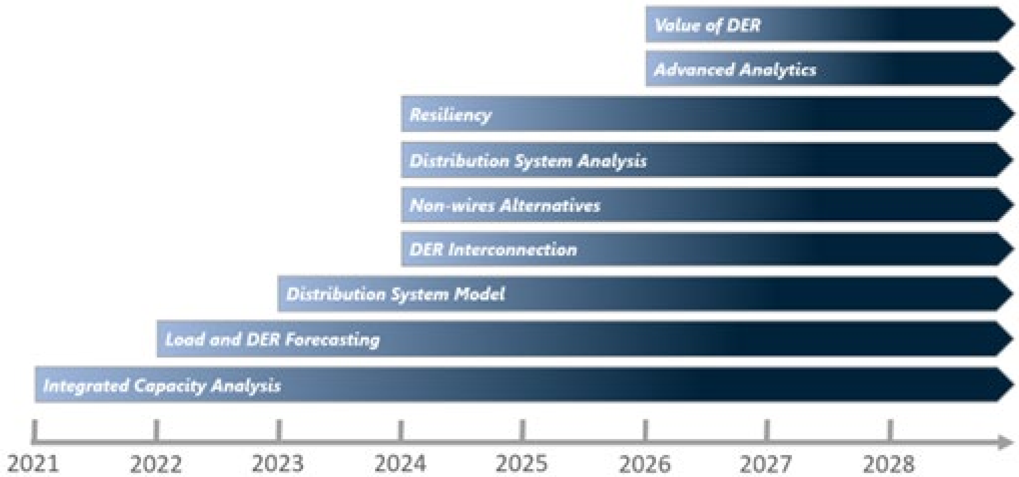
[19] The Company does not use levelized costs to screen DSM programs. DSM programs produce benefits in the form of avoided supply-side capacity and energy costs (*i.e.*, benefits of the DSM programs are reductions in capacity and energy costs and therefore are benefits in that they are reducing the amount of energy and capacity that would otherwise be needed) that are netted against DSM program costs and incentives.

Figure 3.3.1: 2023 IDP Roadmap



The IDP concept is not static, and further changes are expected in the next decade. But the IDP Roadmap sets the Company on a trajectory to give higher priority to foundational components of IDP, such as advanced forecasting and system model enhancements, while balancing the resources required to implement these components and the interdependencies among many of the components.

3.4 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 Winter Storm Elliott demonstrated that extreme weather can challenge the stability of the Eastern Interconnection absent significant new investments.[20]

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 compete with 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.

[20] For example, during Winter Storm Elliott, PJM had to reduce power supplies to TVA due to a transmission operating limit in PJM, and TVA had to shed load. PJM also curtailed non-firm power purchases scheduled to be delivered to Duke Energy on the evening of December 23, 2022 and the morning of December 24, 2022, during Duke Energy's load shed event.

3.4.1 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 solar, wind, and storage resources, with 6.6 GW of new 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.

Federal and 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.

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.

3.4.2 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.

3.5 Nuclear

For over half a century, nuclear energy has provided reliable, affordable, and zero carbon electricity to meet customer load demands and remains a fundamental component of the transition to net zero emissions. As the need for reliable and clean power grows, nuclear power is also a necessary resource to maintain reliability and affordability. Dominion Energy is extending the life of its current nuclear units and prudently considering additional nuclear energy resources in the form of small modular reactors ("SMRs").

3.5.1 Nuclear License Extensions

The Company owns two nuclear stations in Virginia, Surry and North Anna, and each station has two power generating units. These stations serve as baseload, meaning they run most of the time, and ensure reliable supply of energy, which makes them critical for the Company's fleet. The licenses to operate Surry Units 1 and 2 were renewed by the Nuclear Regulatory Commission ("NRC") in May 2021, permitting continued operation through 2052 and 2053, respectively. The NRC issued the license renewals for North Anna Units 1 and 2 in August 2024, allowing the units to operate through 2058 and 2060, respectively. The Company is now completing the upgrades necessary to reliably and safely operate these units in the extended period of operations. Extending the life of the Company's baseload nuclear generation is crucial for maintaining reliability in all weather conditions, especially during demand peaks. At present, the Company operates the only four nuclear units in the United States licensed for 80 years.

3.5.2 Small Modular Reactors

Light water SMRs are based on traditional nuclear reactor designs that have been in use for decades. Specifically, they utilize light water technology, where water is used as both a coolant and a neutron moderator, similar to conventional large-scale nuclear reactors. Advanced non-light water SMRs, often referred to as advanced modular reactors, are based on different principles compared to traditional light water reactors. While they still use nuclear fission to generate heat, they employ alternative coolants such as gas, liquid metal, or molten salt instead of water.

Building on the decades of nuclear power operations, SMRs could play a pivotal role in the growing clean energy mix as a promising future supply-side resource option.

> **Stakeholder Process Highlight**: The 2024 IRP includes SMRs in the model along with a qualitative discussion on the role of SMRs in meeting load demand and the transition to clean energy as well as qualitative discussions regarding long duration storage, and carbon capture, sequestration, and storage.

SMRs are a classification of nuclear reactors with an output of approximately 300 MW of electricity per reactor, although the output varies by design. This output is about one-third of the generating capacity of traditional nuclear power reactors. The modular nature allows for portions of the plant to be factory-fabricated and delivered to the site, improving construction quality and reducing construction timelines.

Through decades of research and development to improve the cost and safety of nuclear power production, SMRs have incorporated design improvements to reduce safety risks. Given the small size and modular construction process, it is possible to locate SMRs on a wide variety of sites, including brownfield sites (*e.g.*, retired fossil-fuel generation sites), existing nuclear power generation sites, other industrial areas, and areas closer to the electric demand. Such sites could be helpful in utilizing existing infrastructure, such as the use of existing interconnection points to the transmission grid.

Among the key benefits and improvements of SMRs over traditional nuclear technology is the increased use of passive safety systems. Passive safety systems rely on natural forces, such as gravity, pressure differences, or natural heat convection to accomplish safety functions without the need for operator action or a power source. This results in a power plant that is simpler, has less equipment, and does not require an emergency back-up source of power. The fabrication of SMRs includes the repeat production of modular assemblies, incorporating a variety of components to a consistent design, reducing cost and time for production, and thus making SMRs scalable.

Another key advantage of SMRs is their capability to produce electricity around the clock, providing reliability and stability to the electric grid. The SMR designs being developed are also expected to be dispatchable, or on-demand, meaning that they will be able to ramp up and down to meet demand within timeframes comparable to those of natural gas-fired CC facilities, thus helping ensure reliability and resiliency and support the integration of more renewable resources into the grid.

Although this technology has not yet been deployed at scale, SMR design activities and regulatory licensing are accelerating both domestically and abroad. The NRC has been actively engaged in licensing activities related to SMRs. Examples include the approval of the design for an SMR developed by NuScale Power, LLC in August of 2020, the issuance of a final safety evaluation for a demonstration reactor to be deployed by Kairos Power in June of 2023, and the acceptance of TerraPower's construction permit application in May of 2024.

Further, state and federal policy changes support the development of SMRs. The 2024 Virginia General Assembly approved and enacted SB454, which allows the Company to petition the SCC for the approval of a rate adjustment clause to recover the costs associated with SMR project development costs along separate development phases. At the federal level, the ADVANCE Act was signed into law in July of 2024. This landmark legislation supports the development and deployment of new nuclear energy technologies by reducing regulatory costs for companies seeking to license advanced nuclear reactor technologies, establishing an accelerated licensing review process to site and construct reactors at existing nuclear sites, and strengthening the U.S. nuclear energy fuel cycle and supply chain infrastructure, among other provisions.

The Company plans to continue to evaluate the feasibility and cost of SMRs. In July of 2024, the Company issued an RFP to leading SMR nuclear technology companies to evaluate the feasibility of developing an SMR at the Company's North Anna Power Station site. The Company plans to update modeling assumptions related to SMRs in future filings based on its continued evaluation of SMR technologies. Based on updated capital, operating and maintenance costs, continued progress of licensing timelines, it is conceivable that the deployment of SMRs could be further accelerated by the Company, with the first SMR being placed in service in the early-to-mid 2030s.

3.6 Reliability Resources Under Development

3.6.1 Natural Gas-Fired Units

Natural gas resources are essential for the energy transition, given they are dispatchable resources that play a vital role in supporting increased reliance on intermittent renewable resources. With flexible operating characteristics, giving them the ability to follow load, natural gas units support the grid to generate energy when it is needed, thus allowing the units 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 to meet large swings in energy output of intermittent generation. For example, Winter Storm Elliott 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. CTs provide the capability to quickly dispatch when needed, with a proven history of being highly available, running reliably, and having the ability to provide energy over a longer period of demand. Availability of backup fuel on site increases the reliability of not only these units but the entire grid by ensuring that electricity can be generated when customers need it the most, even when fuel supplies are constrained. The development of gas-fired generation can take place on brownfield sites to take advantage of existing capacity injection rights ("CIRs"). CTs can also help to address probable transmission system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities, including support for system restoration by providing black start capabilities. See Appendix 2D.

For these reasons, the Company is evaluating sites and equipment for the construction of new gas-fired units. New simple cycle CTs will be dual-fuel capable, have additional onsite backup fuel supply, and will be capable of blending hydrogen. Multiple fueling capabilities provide flexibility to endure multi-day extreme weather events if gas supply is limited. In order to meet the energy and capacity needs associated with the load forecast and without a commercially viable carbon-free, dispatchable generation alternative, CTs will be the critical component to ensuring grid reliability in the near term.

In this 2024 IRP, the Company modeled advanced class CTs, such as the H-Class CT, in two applications. First, utilities are investigating the use of advanced class CTs in a simple-cycle capacity to reduce emissions while maintaining the flexibility to meet peak loads. Currently, there are no commercially operating units in the United States but one unit is operating in a testing capacity. The Company will continue to monitor this technology and refine its assumptions in future IRPs. Second, the Company included an advanced class CC unit, 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' everyday loads.

In order 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.

3.6.2 LNG Storage Facility

The Company's Brunswick County Power Station and Greensville County Power Station are natural gas-fired CC electric generating facilities that commenced operations in 2016 and 2018, respectively. These large and efficient power stations have a combined nameplate capacity of nearly 3,000 MW with the ability to generate enough around-the-clock electricity to serve more than 700,000 Virginia homes. Together, Brunswick and Greensville represent approximately 16% of the Company's total firm capacity in delivery year 2026; therefore, they are critically important components of the Company's generation fleet.

To maintain a readily available, reliable fuel source for these power stations, the Company applied for a Certificate of Public Convenience and Necessity ("CPCN") Amendment to construct a liquefied natural gas ("LNG") Storage Facility (Case no. PUR-2024-00096). The proposed LNG Storage Facility will include pretreatment, liquefaction, storage, and vaporization facilities, as well as station yard pipeline facilities to receive the gas at the LNG Storage Facility and re-deliver the regasified LNG.

3.7 Future Supply-Side Resource Options

The following sections provide details on certain newer supply-side resource options the Company has considered and will continue to evaluate for possible inclusion in future IRPs.

Stakeholder Process Highlight: During the Stakeholder Process the Company received requests from stakeholders to include specific technologies in the IRP modeling such as long duration storage, tidal wave, hydrogen, SMRs and geothermal as well as carbon capture and sequestration. The Company continues to evaluate these technologies and will consider them for future IRPs.

- **Long Duration Energy Storage.** Long duration energy storage ("LDES") technologies can provide longer discharge durations compared to lithium-ion battery storage. LDES systems can be categorized in three segments, based on the technology design: thermal, electrochemical, and mechanical. Across the U.S., pilot projects are being developed to validate technologies, use cases, and garner support for greater levels of commercialization. The Company recently received the SCC's approval to pilot three non-lithium technologies where two of them are LDES technologies. The Darbytown Power Station will pilot two non-lithium-ion technologies, a Zinc-Halide battery capable of discharging for 4-hours and an Iron-air battery capable of discharging for 100-hours. The Virginia State University location will pilot a Nickel-Hydrogen battery technology capable of discharging for 10 hours. Each of these technologies is electrochemical.

- **Advanced Solar System.** Continuous research on solar technologies such as advanced tracking systems, organic, bifacial, and tandem perovskite-silicon modules, and grid-forming inverters, continues to enhance system efficiency and output, reduce intermittency profiles, and increase overall operational efficiency of solar generation. As these technologies mature and reach commercial development, there is an opportunity to expand carbon-free generation with potentially less land use and costs. Additional work is being pursued to develop dual land use at solar sites. Agrivoltaics systems aim to enable agriculture production co-located with solar facilities, including crop production, livestock and sheep grazing among others. Several states such as Massachusetts, New York and Illinois have developed state-level incentives to promote development of agrivoltaics systems at scale.

- **Power Generation Technology with Carbon Capture and Sequestration.** Coal power plants and natural gas CCs equipped with carbon capture and sequestration ("CCS") are consistently modeled as potential alternatives for a low-carbon electric generation portfolio. Low-carbon scenarios developed by the Intergovernmental Panel on Climate Change, the International Energy Agency, Bloomberg New Energy Finance, and others highlight contributions from CCS in achieving significant carbon emission reductions in the electric generation sector. While CCS could enable a considerable amount of existing dispatchable generation to remain operational, its implementation faces significant challenges across the United States, particularly in the Mid-Atlantic region. The primary obstacles include the lack of infrastructure, such as dedicated CO_2 pipelines for transport and suitable underground geologic formations for permanent sequestration. These challenges are especially pronounced in Virginia and North Carolina. Emerging carbon utilization technologies, which aim to use captured carbon as a feedstock in industrial, chemicals, and synthetic fuel sectors, could potentially address some of these infrastructure challenges. However, the scale of carbon utilization is yet to be determined to confirm the technologies' feasibility to be deployed in power generation applications. Dominion Energy continues to engage with technology and infrastructure developers to monitor market progress in this area.

- **Direct Air Capture Technology ("DAC").** This emerging technology is an industrial process designed for the large-scale capture of atmospheric CO_2. DAC technology pulls in atmospheric air, and through a series of chemical reactions extracts the CO_2 while returning the rest to the environment. This process mimics what plants and trees do during photosynthesis, but DAC does it much faster and with a smaller land footprint. Similar to CCS, DAC delivers the CO_2 in a pure, compressed form that can then be stored underground or reused. The potential of the DAC technology is closely tied to electric systems where renewable energy is available at a very low cost to power the industrial process that removes CO_2 from the air. Like CCS, DAC will require infrastructure to support CO_2 transportation and sequestration. Alternatively, the captured CO_2 could be stored in a solid form for safe storage, creating a "negative emissions" industrial scale process. It could also be used for CO_2 enhanced oil field recovery and as a feedstock to produce synthetic fuels, achieving carbon neutral transportation fuels.

- **Methane Pyrolysis.** Methane pyrolysis splits natural gas into hydrogen and solid carbon (such as high-quality graphite), through thermo-catalyst reaction, microwaves, or thermal decomposition. The quality and quantity of hydrogen and solid carbon depend on the system design and the reaction mechanism. This process offers some potential benefits, including the utilization of existing natural gas infrastructure to produce hydrogen at the point of consumption, which reduces the need for extensive transportation and storage infrastructure. Additionally, it provides clean or low-carbon hydrogen with significantly lower CO_2 emissions, which can be used in various emerging clean energy applications, such as power generation. The solid carbon can be used in multiple applications, including the production of lithium-ion batteries, asphalt, and other manufacturing processes. However, challenges remain, such as the dependency on the solid carbon market to support low cost of hydrogen. Companies developing these systems are targeting various potential carbon markets based on their technology and quality of solid carbon produced, but the ability of these markets to absorb the new source of carbon needs to be better understood to accurately assess the economic viability of this alternative. Additionally, availability of natural gas to support the hydrogen requirements and the reliability of these emerging technologies need to be evaluated to determine the best use cases.

- **Hydrogen.** Hydrogen is a versatile energy carrier that can store and transport energy, supporting the decarbonization of hard to abate sectors of the economy. Opportunities exist in the production, transportation, and utilization of hydrogen to foster a clean energy future, particularly when produced from low- or no-carbon sources. Hydrogen produced using excess renewable energy, which may become available as more renewable generation resources are added to the grid, offers medium- and long-term energy storage opportunities for later use in natural gas power plants, particularly to meet peak demands. Additionally, emerging hydrogen production technologies, such as methane pyrolysis and waste biomass reformation, could reduce the energy requirements from electrolysis. These advancements could make hydrogen production and delivery more cost-effective, especially when integrated with natural gas-fired CC plants. CT manufacturers and other power generation technologies are working to increase the proportion of hydrogen that can be blended with natural gas. Overall, the implementation of hydrogen as a fuel for power generation will depend on specific use cases and achieving several milestones, such as the development of hydrogen infrastructure to produce, transport, and store hydrogen at the scale required for different power generation technologies, as well as improvements in production efficiency and cost reduction.

- **Fusion.** Fusion offers a potential long-term firm clean energy source. Fusion, the opposite of fission, occurs when two nuclei combine to form a new nucleus, producing large amounts of energy. Fusion energy has seen significant advancements recently, with several key developments aimed at accelerating and demonstrating the technology's potential. In 2022, the White House announced a "Bold Vision" for deploying commercial fusion energy within a decade. In 2023, the NRC voted unanimously to regulate fusion energy under their byproduct material framework (10CFR30), the same framework used to regulate particle accelerators and medical research facilities. In 2023, the U.S. Department of Energy announced $46 million in funding to eight private fusion energy companies working on research, development and deployment of fusion power plants: a major step to achieve the Administrations Bold Decadal Vision and deploy pilot-scale demonstrations of fusion within a decade. Private investments from fusion energy companies have attracted over $7 billion to complement federal grants for the purpose of accelerating research and development in the field. According to the Fusion Industry Association, a non-profit trade organization, 70% of its member companies are targeting the early 2030s for the first fusion power plants. Scientific breakthroughs in fusion have also occurred in the U.S. and abroad, including the National Ignition Facility's experiment, exceeding scientific energy break-even in December of 2022, and a new world record for the amount of energy extracted from a fusion reaction at the UK-based JET laboratory set. These developments highlight the growing momentum and potential of fusion energy as a safe, abundant, and zero carbon energy source for the future.

- **EVs as a Resource.** EVs are becoming more prolific in most forms of transportation. With EVs, new technologies and software are being developed to maximize the benefits of electrification, such as load shifting and other applications that complement renewable generation. For example, vehicle-to-grid ("V2G") technologies are being developed through which electricity stored in EV batteries can be fed back onto the grid to lower peak demand or to provide grid support. See Appendix 3L, for a discussion of the Company's Electric School Bus Program through which it seeks to explore V2G technology. A precursor to taking advantage of this resource is a modernized grid that has full situational awareness.

3.8 The Five-Year Reliability Plan

Over the next five years (*i.e.*, 2025 to 2029), 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.

3.8.1 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, as further discussed in Chapter 3.6.1.
    - Continue evaluating opportunities for uprates or increased CIRs at existing generating units, as presented in Appendix 3B-11.

    - Continue to pursue regulatory approvals of the LNG Storage Facility to ensure reliable supply of fuel for the Brunswick and Greensville Power Stations.
    - Advance the development of SMRs, as discussed in Chapter 3.5.2.
    - Update retirement analysis of the Company's thermal generators on an annual basis, as discussed in Chapter 5.5.
- 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.
- Pilot energy storage projects, as discussed in Chapter 3.2.4.

3.8.2 Demand-Side Management

Dominion Energy will continue to identify and propose new, revised, or bundled DSM programs that work towards the proposed program targets of the GTSA and the energy savings targets of the VCEA and beyond in conjunction with the established DSM stakeholder process and the directional recommendations from the Company's long-term DSM plan. The Company recently completed a new DSM market potential study in May 2024 and used this as a basis for proposing future energy savings targets for 2026-2028 in a proceeding before the SCC.

In Virginia, Dominion Energy filed its Phase XII DSM application in December 2023, seeking approval of four new programs as a continuation of prior programs nearing completion, as well as enhancements to several existing programs. The SCC issued its final order approving the programs and enhancements on July 26, 2024.

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.

3.8.3 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. Working 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, including 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.

3.8.4 Distribution

The proliferation of distributed renewable, inverter-based resources significantly contributes 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, 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.

3.8.5 Increasingly Clean Actions in the Short-term

Dominion Energy continues to deliver on its commitment to making increasingly clean energy. As such, the Company plans to:

- Continue to evaluate the new Environmental Protection Agency ("EPA") regulations and their impact on the existing generation fleet and proposed new units.
- Maintain environmental stewardship over our legacy generation assets.
- Continue to execute on the VCEA mandates, including:
    - File annual plans for the development of solar, onshore wind, and energy storage resources consistent with the requirements established by the VCEA, including related requests for approval of CPCNs and for prudence determinations related to PPAs;
    - Complete construction of CVOW with a target in-service date of late 2026;
    - Continue construction and begin operation of approved solar and storage projects; and,
    - Comply with Virginia's mandatory RPS Program at a reasonable cost and in a prudent manner, and submit annual compliance certification to the SCC.
- Continue to evaluate renewable energy interconnection and integration costs.
- 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.

- Continue offering clean energy tariff to customers committed to supporting faster transition to clean energy through consuming electricity produced by renewable generators (directly or through purchased RECs/other carbon offset mechanisms).
- Administer the DSM and energy efficiency programs, listed in Appendices 3E and 3F;
- Continue evaluation of new technologies, further discussed in Chapter 3.7.
- Continue to evaluate pilot energy storage projects associated with the battery storage pilot program established by the GTSA, including LDES and non-lithium-ion technologies.
- Continue publishing hosting capacity maps for utility-scale and net metering DERs and transportation electrification.
- Continue to expand EV product offerings for customers.
- Continue to pilot V2G technology through the Electric School Bus Program.

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, particularly in New England, rely to a greater extent on natural gas 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 2024, the rate paid by a typical residential customer of Dominion Energy increased by about a 1.14% CAGR, while the rate paid by a typical large industrial customer decreased on a compound annual basis by about 0.9%. Over the same time period, the Consumer Price Index for All Urban Consumers, a proxy for inflation, increased by a CAGR of 2.226%

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 4.1.3 shows states by average commercial price per kilowatt hour ("kWh") and average consumption per commercial customer.

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

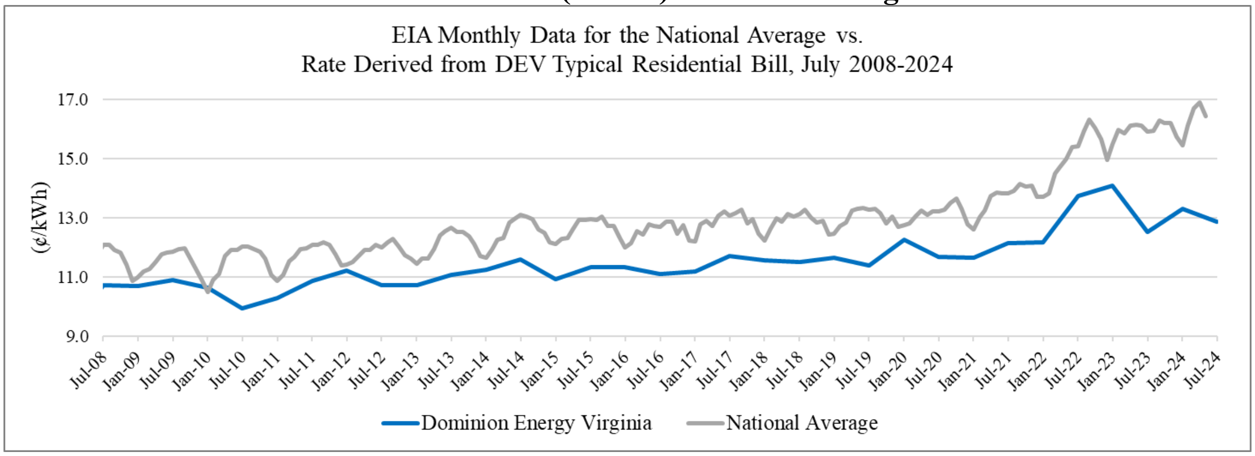


Figure 4.1.2: Historical Dominion Energy Industrial Rate vs. EIA National Average

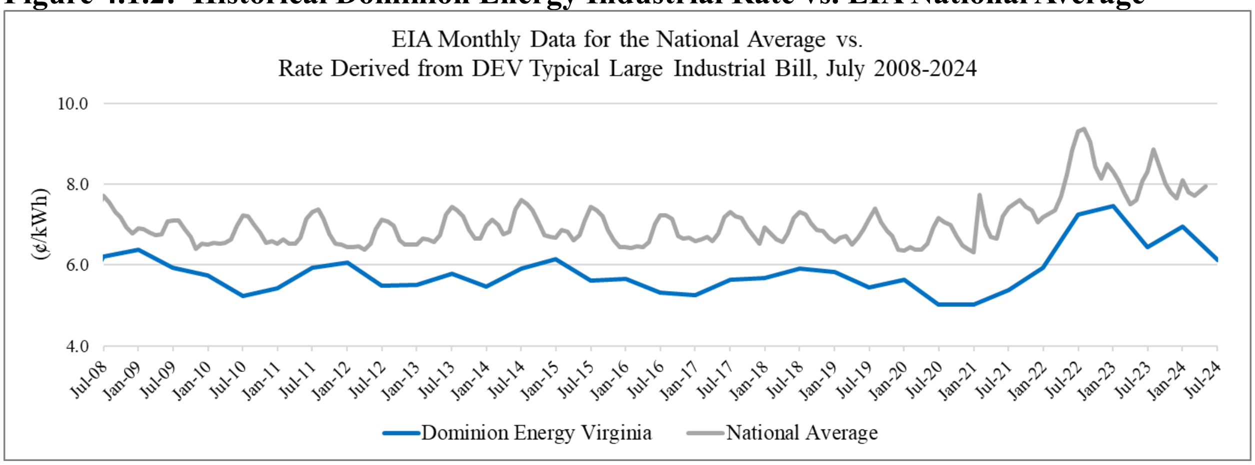
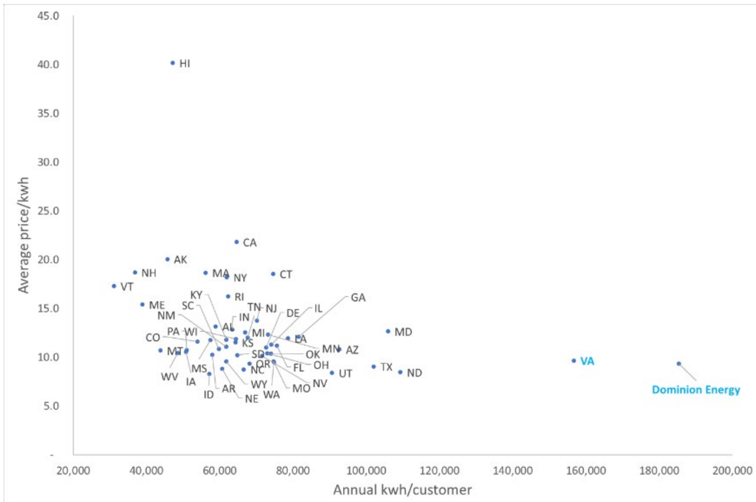


Figure 4.1.3: States by average commercial price per kWh and average consumption per commercial customer[21]



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 primary Portfolio presented in the 2024 IRP. The analysis encompasses three different customer classes and spans 2019 through 2039.

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, along with results of the bill analysis using both methodologies. From the Company's perspective, the Directed Methodology, which assumes no load growth, is increasingly unlikely as it reflects the cost of a build plan to meet substantial growth but not the actual growth over which to spread the associated costs. Considering actual connects, load growth, customer commitments, and the results of the recent PJM capacity auction, all factors point to substantial load growth, especially in the commercial sector.

[21] 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/.

That being said, 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** (excludes load growth)			
	Projected Bill	CAGR Dec. 2019	CAGR May 2020	CAGR Oct. 2024	Projected Bill	CAGR Dec. 2019	CAGR May 2020	CAGR Oct. 2024
12/31/2019	$122.66				$122.66			
5/1/2020	$116.18				$116.18			
10/1/2024	$142.77				$142.77			
Year End 2035	$215.62	3.59%	4.03%	3.73%	$277.31	5.23%	5.71%	6.08%
Year End 2039	$214.24	2.83%	3.16%	2.70%	$315.25	4.83%	5.21%	5.33%
Total Bill Increase (2035)		$92.96	$99.44	$72.85		$154.65	$161.13	$134.54

4.2.2 North Carolina

The NCUC, in its Order[22] dated August 16, 2024, directed that Dominion Energy work with the NCUC – Public Staff ("NC Public Staff") to develop a North Carolina-specific bill analysis, based on system-wide plans and include the analysis in the 2024 IRP. The Company and NC Public Staff discussed potential assumptions for the North-Carolina-specific bill analysis and this methodology is based on those assumptions. Additional detail about the methodology is provided in Appendix 4B.

The methodology forecasts incremental system revenue requirements and system residential bill impact differences associated with the VCEA with EPA Portfolio.

This bill impact analysis holds current base rates, fuel Rider A, and non-fuel rider rates constant throughout the analysis. Future bill changes are reflective of an estimated impact of the VCEA with EPA Portfolio on system operational costs and investments from 2025 through 2039. The estimated revenue requirements underlying the analysis are assumed to be recoverable each year for existing plant and for the year that each project commences commercial operations for new investment. The Company has not declared a cadence of future regulatory filings and this analysis is not intended to indicate such a cadence. The intent is to show how the VCEA with EPA Portfolio

[22] *In the Matter of 2023 Integrated Resource Plan and 2023 REPS Compliance Plan of Dominion Energy North Carolina,* Order Accepting 2023 IRP and REPS Compliance Plan and Providing Further Direction for Future Planning at 18, Docket No. E-100 Sub 192 (Aug. 16, 2024).

could impact customer bills. Figure 4.2.1.2 shows the results of the bill impact analysis for North Carolina.

Figure 4.2.1.2: North Carolina Residential Bill Projections (1,000 kWh per month)

	Projected Bill	CAGR
Year End 2024	$127.73	
Year End 2035	$201.96	4.3%
Year End 2039	$204.37	3.2%
Total Bill Increase (2035)	$76.64	

Chapter 5. Comparative Analysis of Strategic Pathways that Underpin the Primary Portfolios Over 15 Years

The projected resource mix is largely similar across the two REC RPS Portfolios and the two VCEA Portfolios as most of the resources available for inclusion in the primary Portfolios were needed. This continues to bolster the need for an "all of the above" approach.

Renewable generators and energy storage will comprise almost half of the Company's installed capacity mix (which also includes capacity purchases) by 2039, and the proportion of energy supplied by these resources increases from 3% in 2025 to approximately 30% in 2039. As a result, the carbon intensity decreases across all Portfolios, including those Portfolios that did not include the suite of 2024 EPA regulations.

All primary Portfolios also include the maximum possible amount of new offshore wind, SMRs, and natural gas-fired resources. Dispatchable generation will provide steady supply of energy and capacity through the Planning Period and are essential for ensuring reliability.

5.1 Overview of the Primary Portfolios

Dynamic shifts in Dominion Energy's planning environment include increasing load, higher and more frequent peaks in customer demand, significant changes to the PJM capacity market, and new federal environmental regulations, among others. These developments are reflected in updated planning assumptions underpinning this 2024 IRP, and their potential impacts on the Company's capacity and energy positions. Since resource needs are more predictable over a shorter time horizon, the Company has chosen to focus on the 15-year Planning Period mandated by statutes and guidelines of both Virginia and North Carolina. This allows the Company to use reasonable assumptions to develop an array of plausible pathways to reliably serving load over the next 15 years.

The EPA has recently finalized a suite of new environmental standards that affect the electric utility sector. These new standards include: (1) Federal Implementation Plan for the 2015 Ozone National Ambient Air Quality Standards (commonly referred to as the Good Neighbor Rule), (2) National Emission Standards for Hazardous Air Pollutants for Coal and Oil Fired Electric Generating Units (commonly referred to as the "Mercury and Air Toxics Standards" ("MATS")), (3) Supplemental Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category ("ELG"), (4) Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities: Legacy Surface Impoundments, and (5) New Source Performance Standards for Greenhouse Gas Emissions from New, Modified and Reconstructed Fossil Fuel Fired Electric Generating Units (111(b)) and Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil fuel-fired Electric Generating Units (111(d)). Appendix 5A provides additional details about these and other environmental regulations that regulate air, solid waste, water, and wildlife.

The implications of these new environmental regulations include potential retirements of fossil-fueled generators, which could in turn impact future fuel availability and prices, capacity prices, and energy prices, commonly referred to as a commodity complex. However, those new environmental standards all face legal challenges at this time, and the outcomes and the timings of the outcomes will be uncertain. Therefore, for this 2024 IRP, and to act as bookends on the analysis, two different commodity price forecasts were utilized to develop the primary Portfolios. One forecast assumes that environmental regulations in their current form as of May 2024 withstand the legal challenges (*i.e.*, environmental commodity price forecast), as a whole (which is not to say this is a probable outcome). Another forecast assumes that the new environmental standards do not withstand the legal challenges (*i.e.*, standard commodity price forecast) and therefore does not incorporate potential impact of these regulations, again, as a whole (also, not a probable outcome). Hence, the term "bookends," that while neither bookend is a probable outcome, it is valuable to consider them both as the probable outcome will be somewhere in between at a future date that is currently unknown.

Similarly, the Company needed to make certain compliance assumptions related to these new environmental regulations for the 2024 IRP modeling. The Company modeled compliance with 111(b) by limiting the capacity factors to 40% for both the generic 2x1 CC and advanced class CT units, and 20% for the generic 7F CT which were included in the modeling as new resources. For 111(d), the company modeled compliance by converting the Company's three remaining coal stations to burn natural gas by January 1, 2030, using costs published by the EPA. Similarly, the EPA published ELG compliance costs for the Clover Power Station, those costs were used to model compliance at all three coal stations. For MATS, the Company included $1.5 billion in additional capital costs for the Mount Storm Power Station as a high-level estimate of the cost to comply with the regulation. *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.*

In this 2024 IRP, the Company presents four primary Portfolios to meet customers' needs in the future under different planning assumptions. These Portfolios are designed using constraint-based least-cost planning techniques and proven energy generation technologies. Figure 5.1.1 below provides an overview of the Portfolios and the high-level assumptions underlying each Portfolio. 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 assuming the build plans for each primary Portfolio are provided in Appendix 5C.

Figure 5.1.1: Summary of Primary Portfolios, Sensitivity for NCUC and a Stakeholder Input Case

	1	2	3	4		
Name	REC RPS Only with EPA	REC RPS Only without EPA	VCEA with EPA	VCEA without EPA	NCUC Directed	Stakeholder Input
	Primary Portfolios				Sensitivity	Stakeholder Process
Description	RPS Only with EPA Environmental Regulations	RPS Only without EPA Environmental Regulations	RPS and VCEA Development Targets with EPA Environmental Regulations	RPS and VCEA Development Targets without EPA Environmental Regulations	NCUC Solar and Storage Build Limits	Stakeholder input with no new natural gas resources
Meets RPS Program (i.e., REC retirements) Requirement?	Yes					
Forced VCEA Development Targets?	No	No	Yes	Yes	Yes	Yes
Renewable Utility/PPA	Model Optimized	Model Optimized	65/35	65/35	65/35	65/35
REC Purchases	30%					
EPA Environmental Regulations (Finalized Rules as of 4/2024)	Yes	No	Yes	No	Yes	Yes
Solar Build Limits (MW)	1,020				Ramps Up 1,020 to 2,040	2,040
Storage Build Limits (MW)	350				Ramps Up 350 to 700	700
Onshore/Offshore Wind (MW)	60/3,400 (15-year limit)					60/6,000 (15-year limit)
Nuclear Build Limits (starting in 2034) (MW)	268					536
CCs (2x1) (MW)	2,536					None
CTs (3 Advanced Class) (MW)	2,454					None
CTs (1 7F) (MW)	944					None
Capacity Imports (Purchases) (MW)	3,300					6,600
Energy Imports	20% of Annual					
Retirements	Least Cost Optimized					
Load Forecast	PJM					
EE	Aligned with goals established in SCC's pending target setting proceeding; Beyond 2028 based on proposed targets with reasonable increase based on savings potential					

Stakeholder Process Highlight: The Company received feedback from stakeholders on showing a VCEA compliant plan that does not build new natural gas units. See the Stakeholder Process Report in Appendix 1.

An overview of the modeling results for each Portfolio are presented in the Table 5.1.2 below.

Table 5.1.2: Modeling Results Summary

	REC RPS Only with EPA	REC RPS Only without EPA	VCEA with EPA	VCEA without EPA
Net Present Value ("NPV") Total ($B)	$100.2	$93.7	$102.9	$97.0
Approximate CO_2 Emissions from Company in 2029 (Metric Tons)	19.6 M	25.0 M	19.3 M	24.6 M
Solar (MW)	11,932	11,932	12,210	12,210
Wind (MW)	3,460	3,460	3,460	3,460
Storage (MW)	4,577	4,577	4,100	4,100
Nuclear (MW)	1,340	1,340	1,340	1,340
Natural Gas Fired (MW)	5,934	5,934	5,934	5,934
Retirements (MW)	-	-	-	-

REC RPS Only With EPA Portfolio

The main assumptions for the REC RPS Only with EPA Portfolio are that it meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA.[23] It was designed utilizing the environmental commodity price forecast from ICF. The Company presents this Portfolio in compliance with prior SCC and NCUC orders for a "least cost plan" and for cost comparison purposes, only. For this Portfolio, the Company allowed the model to select any reasonable resource (*i.e.*, the model was not forced to select any specific resource). Consistent with this directive from prior orders, the Company did not exclude carbon-emitting resources as an option to reliably meet customers' energy and capacity needs and allowed the model to select the retirement dates for existing units on a least-cost optimization basis without regard for other factors that the Company considers when evaluating unit retirements. It is important to emphasize that this Portfolio does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. The Company does not consider this Portfolio as a viable or realistic alternative path forward based on these concerns, as well as the over-reliance on third-party solar PPAs to meet customer needs, which comes with risks related to project execution. It is worth noting that even in this Portfolio, where all of the Company's existing resources stay online, a significant amount of new development is required to meet growing customer capacity and energy needs.

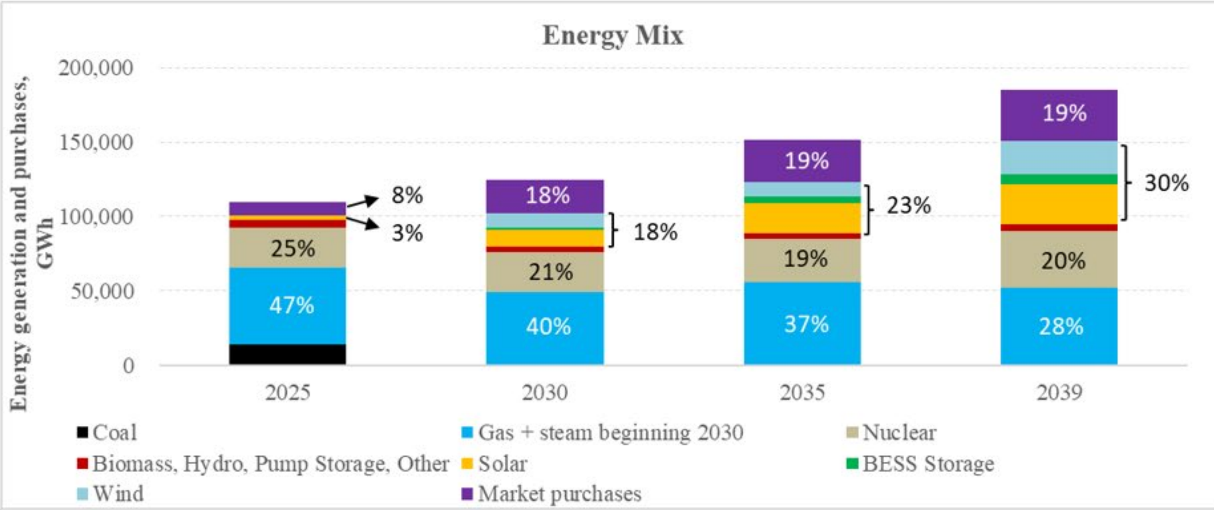
Figure 5.1.3: REC RPS Only With EPA Portfolio Build Summary

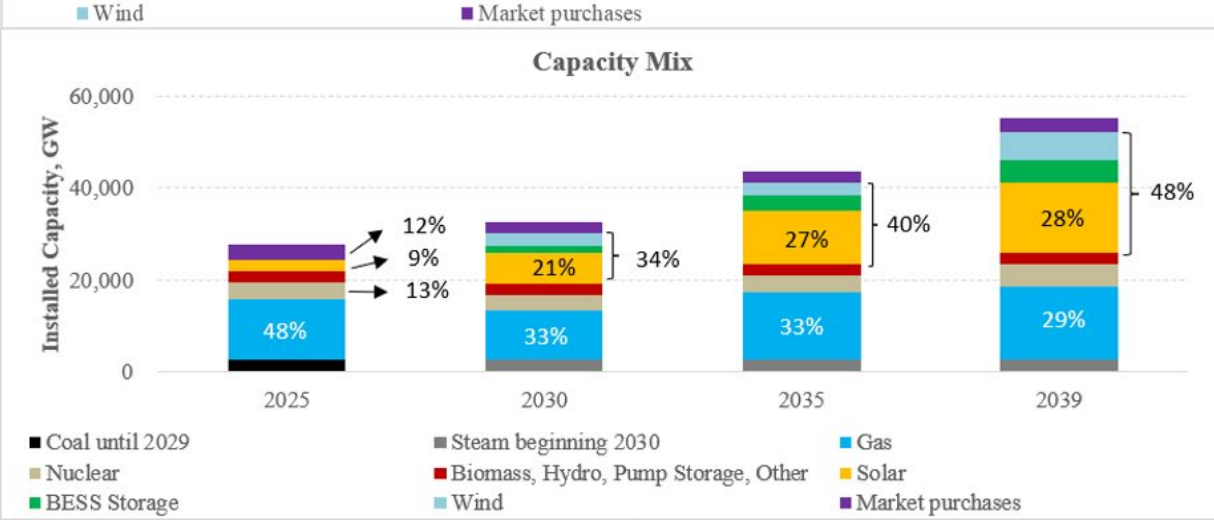
Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2025	20	-	-	-	-	-	-	2,352	-
2026	-	-	-	-	150	-	-	3,200	-
2027	206	-	4	-	92	-	-	2,300	-
2028	482	-	-	-	485	-	-	2,800	-
2029	1,020	-	-	-	350	-	-	2,700	-
2030	1,020	-	-	-	350	944	-	2,400	-
2031	1,020	-	-	60	350	-	-	2,800	-
2032	1,020	-	-	-	350	818	-	2,600	-
2033	1,020	-	-	-	350	818	-	2,800	-
2034	1,020	-	-	-	350	818	-	3,300	-
2035	1,020	-	-	-	350	1,268	268	2,700	-
2036	1,020	-	-	-	350	1,268	268	2,300	-
2037	1,020	-	-	2,600	350	-	268	2,400	-
2038	1,020	-	-	-	350	-	268	2,900	-
2039	1,020	-	-	800	350	-	268	3,300	-
Total	**11,928**	**-**	**4**	**3,460**	**4,577**	**5,934**	**1,340**	**40,852**	

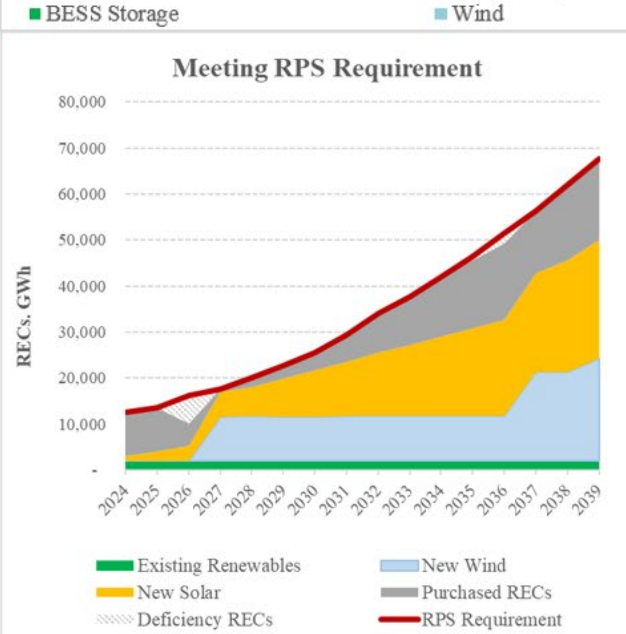
Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units

[23] The mandatory RPS Program requires the Company to 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. Va. Code § 56-585.5 C.

REC RPS Only With EPA Portfolio Dashboard







REC RPS Only Without EPA Portfolio

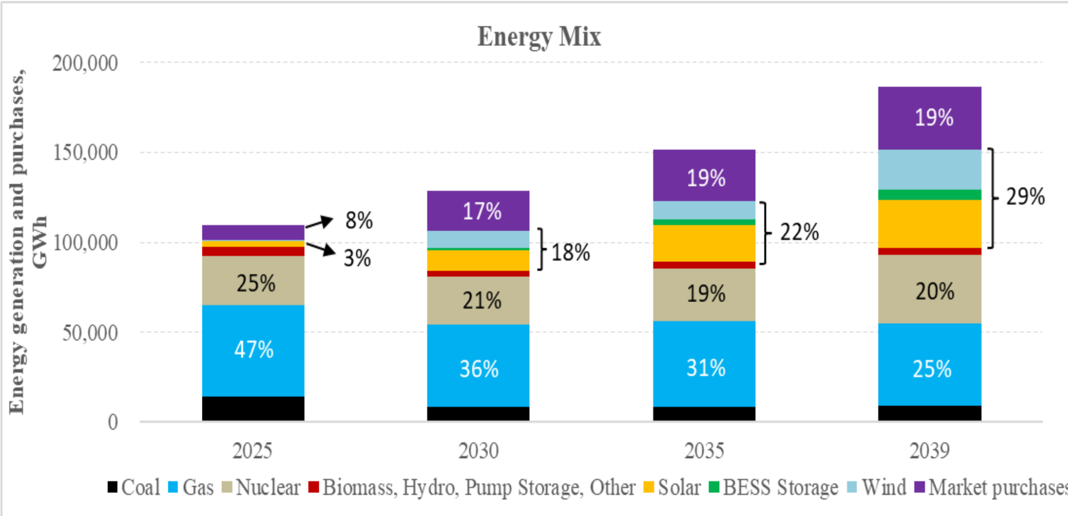
Like the REC RPS Only with EPA Portfolio, this Portfolio meets only applicable carbon regulations (before the new suite of EPA regulations was finalized) and the mandatory RPS Program requirements of the VCEA. In addition, similar to the REC RPS Only with EPA Portfolio, this Portfolio does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Different from the REC RPS Only with EPA Portfolio, this scenario utilizes the standard commodity price forecast.

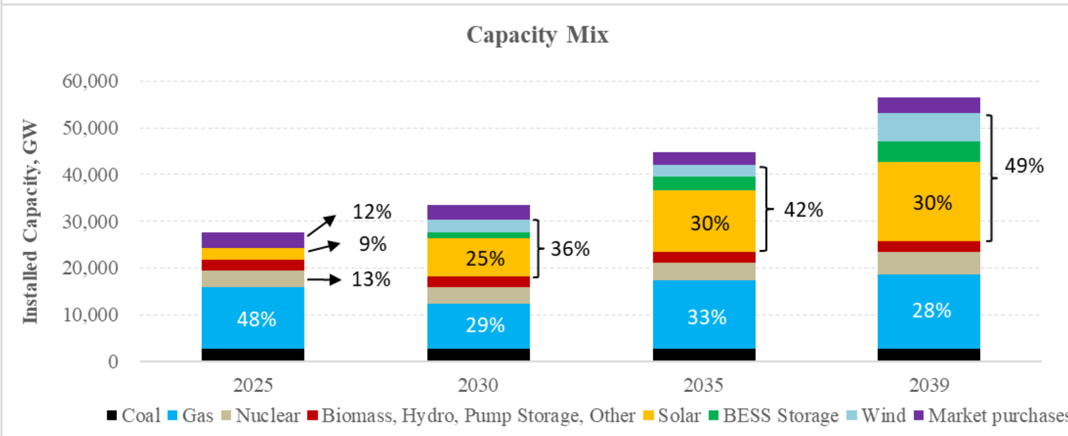
Figure 5.1.4: REC RPS Only Without EPA Build Plan Summary

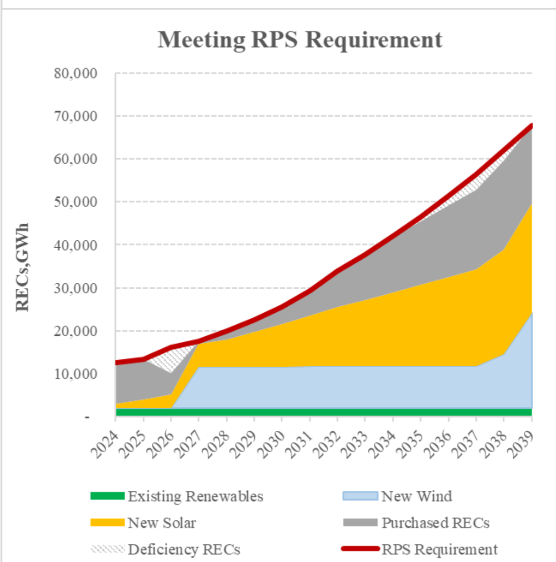
Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2025	20	-	-	-	-	-	-	2,352	-
2026	-	-	-	-	150	-	-	3,200	-
2027	206	-	4	-	92	-	-	2,300	-
2028	482	-	-	-	485	-	-	2,800	-
2029	1,020	-	-	-	350	-	-	2,700	-
2030	1,020	-	-	-	350	-	-	3,200	-
2031	1,020	-	-	60	350	944	-	2,800	-
2032	1,020	-	-	-	350	818	-	2,600	-
2033	1,020	-	-	-	350	818	-	2,800	-
2034	1,020	-	-	-	350	818	-	3,300	-
2035	1,020	-	-	-	350	1,268	268	2,700	-
2036	1,020	-	-	-	350	1,268	268	2,300	-
2037	1,020	-	-	-	350	-	268	2,900	-
2038	1,020	-	-	800	350	-	268	3,200	-
2039	1,020	-	-	2,600	350	-	268	3,300	-
Total	**11,928**	**-**	**4**	**3,460**	**4,577**	**5,934**	**1,340**	**42,452**	

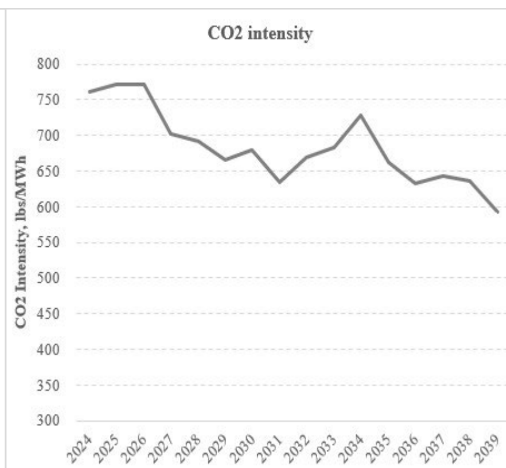
Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units

REC RPS Only Without EPA Portfolio Dashboard









VCEA With EPA Portfolio

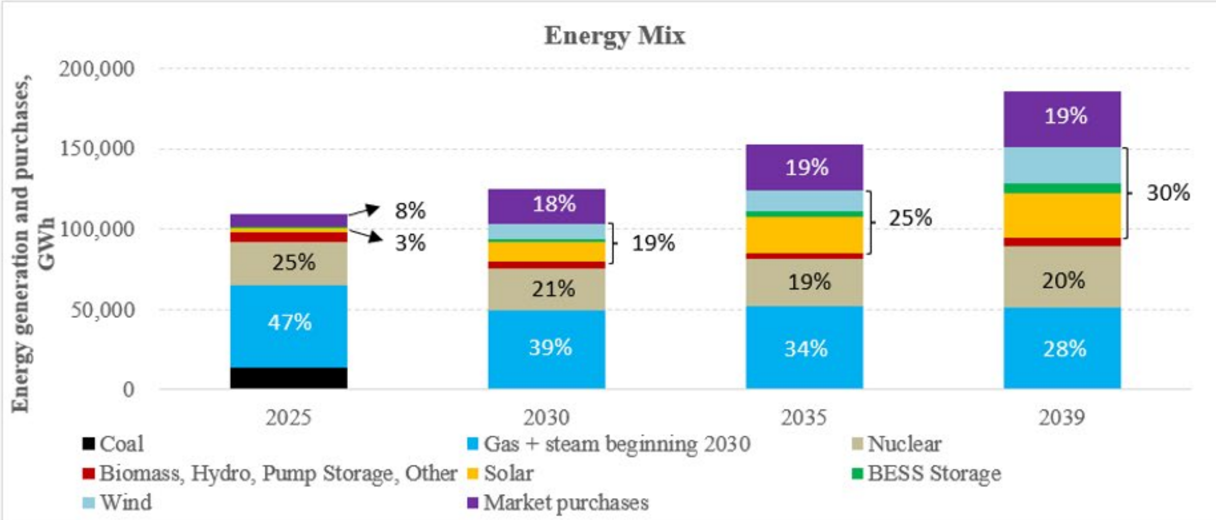
The VCEA with EPA Portfolio, which utilizes the environmental commodity price forecast, includes the significant development of solar, wind, and energy storage envisioned by the VCEA, petitioned by 2035 and built by 2039. Furthermore, this Portfolio builds additional solar and storage resources in the form of PPAs, beyond what is required in the VCEA, building a total of 12.2 GW of solar and 4.1 GW of storage resources. This Portfolio also includes the development of five SMRs starting in 2035 and 3.5 GWs of additional offshore wind. This Portfolio necessarily preserves existing generation in order to maintain reliability and includes 5.9 GW of additional gas-fired assets to address future energy and system reliability needs.

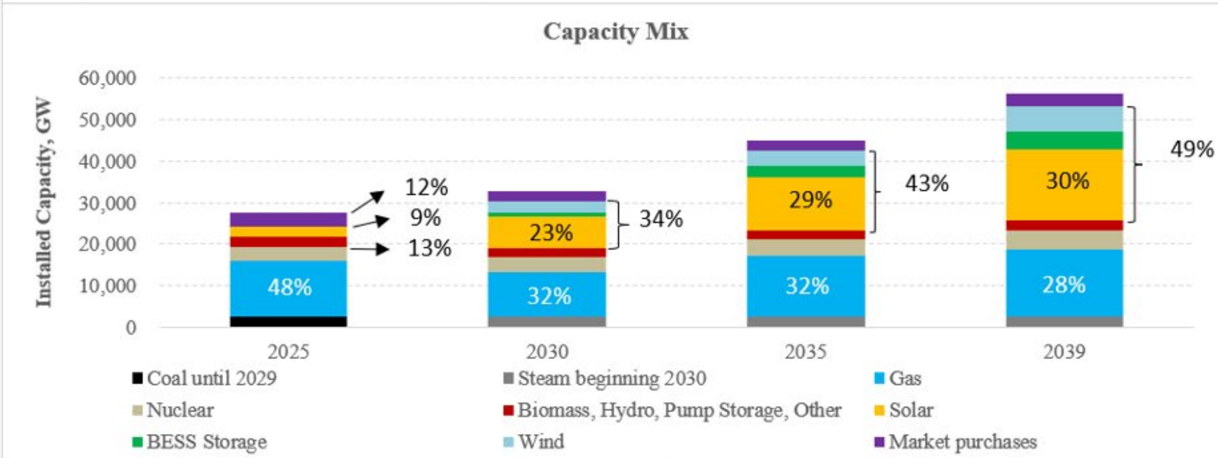
Figure 5.1.5: VCEA With EPA Build Plan Summary

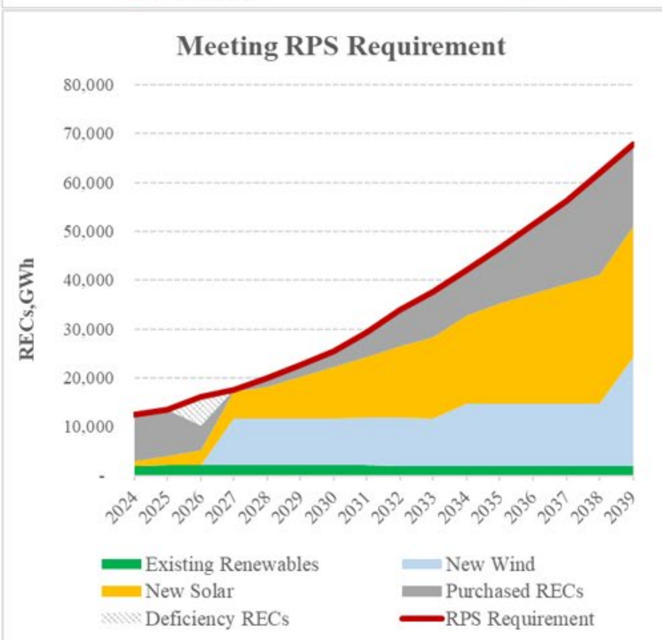
Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2025	-	-	-	-	-	-	-	2,352	-
2026	-	-	-	-	-	-	-	3,200	-
2027	-	-	-	-	-	-	-	2,300	-
2028	-	-	-	-	250	-	-	2,800	-
2029	591	429	45	-	350	-	-	2,800	-
2030	591	429	66	-	350	944	-	2,500	-
2031	552	468	75	60	350	-	-	2,800	-
2032	552	468	87	-	350	1,268	-	2,200	-
2033	552	468	96	-	350	818	-	2,400	-
2034	552	468	99	800	350	818	-	2,700	-
2035	552	468	102	-	350	818	268	2,500	-
2036	552	468	102	-	350	1,268	268	2,200	-
2037	552	468	105	-	350	-	268	2,700	-
2038	552	468	108	-	350	-	268	3,200	-
2039	552	468	105	2,600	350	-	268	3,300	-
Total	**6,150**	**5,070**	**990**	**3,460**	**4,100**	**5,934**	**1,340**	**39,952**	

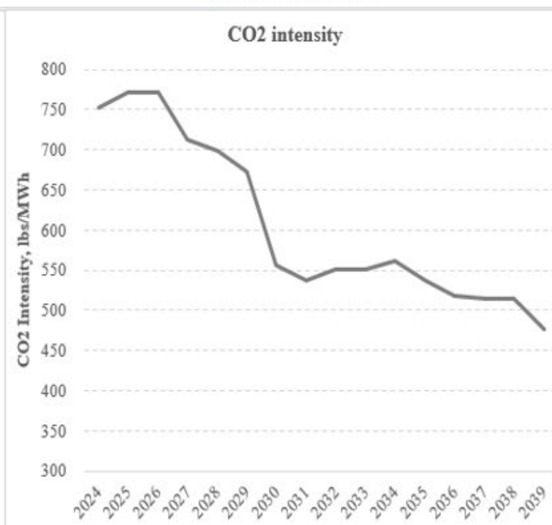
Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units

VCEA With EPA Portfolio Dashboard









VCEA Without EPA Portfolio

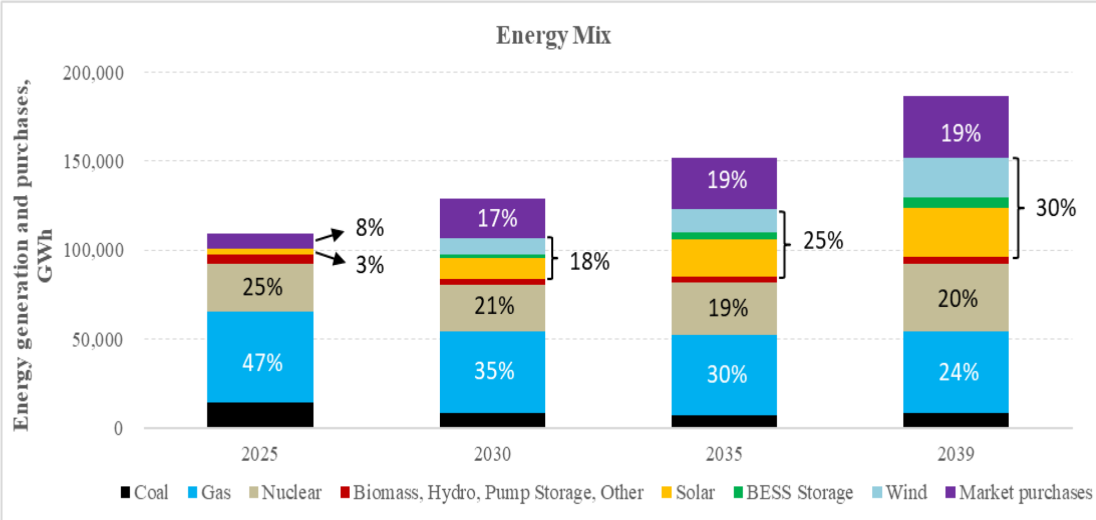
The VCEA without EPA Portfolio utilizes the standard commodity price forecast. The resource totals build for this scenario mirrors those for the VCEA with EPA Portfolio, building a total of 12.2 GW of solar, 4.1 GW of storage resources, 1.34 GWs of SMRs, 3.5 GWs of additional offshore, and 5.9 GW of additional gas-fired generation.

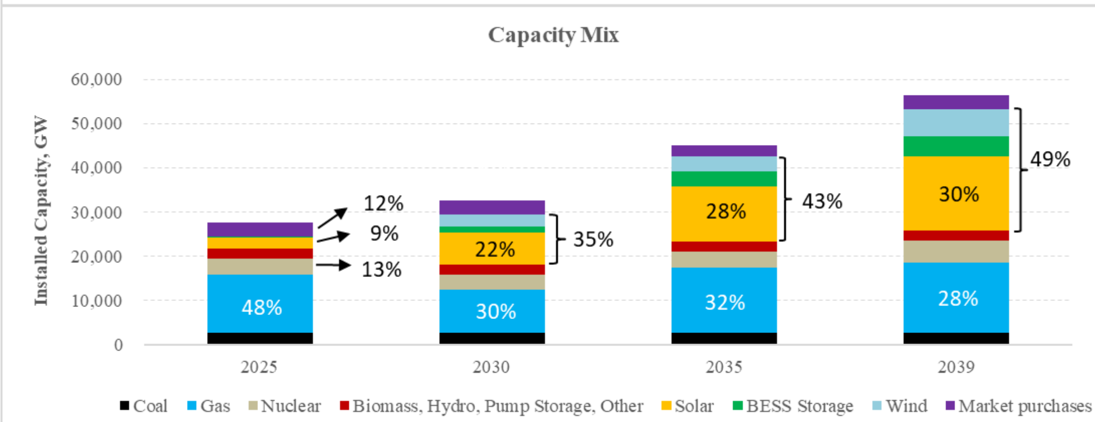
Figure 5.1.6: VCEA Without EPA

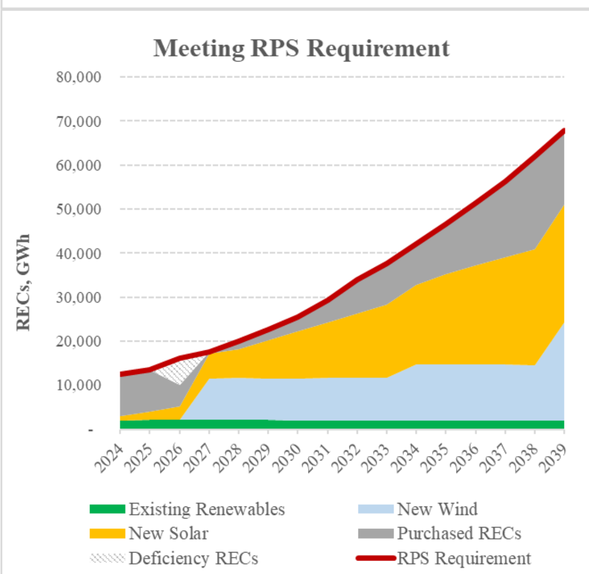
Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2025	-	-	-	-	-	-	-	2,352	-
2026	-	-	-	-	-	-	-	3,200	-
2027	-	-	-	-	-	-	-	2,300	-
2028	-	-	-	-	250	-	-	2,800	-
2029	591	429	45	-	350	-	-	2,800	-
2030	591	429	66	-	350	-	-	3,200	-
2031	552	468	75	60	350	944	-	2,800	-
2032	552	468	87	-	350	818	-	2,600	-
2033	552	468	96	-	350	818	-	2,800	-
2034	552	468	99	800	350	818	-	3,100	-
2035	552	468	102	-	350	1,268	268	2,500	-
2036	552	468	102	-	350	1,268	268	2,200	-
2037	552	468	105	-	350	-	268	2,700	-
2038	552	468	108	-	350	-	268	3,200	-
2039	552	468	105	2,600	350	-	268	3,300	-
Total	**6,150**	**5,070**	**990**	**3,460**	**4,100**	**5,934**	**1,340**	**41,852**	

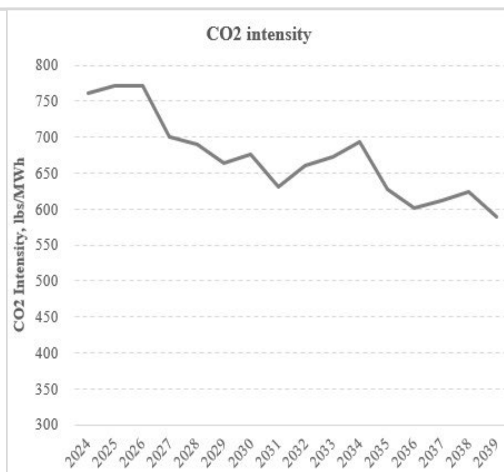
Notes: “COS” = cost of service; “PPA” = power purchase agreement; “DER” = distributed energy resources, whether Company-owned or PPA; “Wind” includes both on and offshore wind units

VCEA Without EPA Portfolio Dashboard









5.2 Modeling Results for the Portfolios

5.2.1 Overview of the Results of the Primary Portfolios

The following are key observations for the primary Portfolios:

- Due to changes in the PJM Market along with an increasing load forecast, the model was capacity-limited.
- Nuclear units provide a steady supply of energy and capacity throughout the Planning Period and are essential for ensuring reliability.
- VCEA resources (*i.e.*, solar, wind, battery storage) will comprise less than 10% of the Company's installed capacity mix (which also includes capacity purchases) in 2025, but almost 50% in 2039. The proportion of energy supplied by these resources increases from 3% in 2025, to approximately 30% in 2039.
- Natural gas-fired generators contribute similar proportions of energy and capacity in the Portfolios, which decrease from just below 50% in 2025, to below 30% by 2039.
- Even with the addition of almost 6 GW of new natural gas-fired generation, the carbon intensity decreases across all Portfolios, including those Portfolios that did not include the new suite of EPA regulations.
- Build plans were similar across the two REC RPS Portfolios and the two VCEA Portfolios. This was due to the model being extremely capacity constrained to the point it needed to build most of the resources available to it. All Portfolios built the maximum amount of new offshore wind, SMRs, and natural gas that they were allowed to build.
- The NPVs for the Portfolios that include the new suite of EPA regulations is \$6 to \$6.5 billion more costly than those that do not.
- By 2030, all Portfolios show the proportion of energy purchases from the market approaching their upper limit set in the model of 20%, and stays near this limit through 2039. This means that the Company can only meet long-term demand if it relies on the PJM market to satisfy up to 20% of its customers' energy needs.

5.2.2 NPV of the Primary Portfolios

Dominion Energy evaluated the four primary Portfolios to compare the NPV[24] utility costs over the Planning Period. Table 5.2.2 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 5.2.2: NPV results for the Primary Portfolios

($B)	REC RPS Only with EPA	REC RPS Only without EPA	VCEA With EPA	VCEA Without EPA
Total System Costs	78.6	72.1	81.3	75.4
Grid Plan (Net of Benefits)	(1.6)	(1.6)	(1.6)	(1.6)
SUP	0.9	0.9	0.9	0.9
Transmission	22.4	22.4	22.4	22.4
Total Plan NPV	**100.2**	**93.7**	**102.9**	**97.0**
Portfolio Delta vs. REC RPS Only with EPA	-	-	2.8	3.3

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 5.1.3 through 5.1.6 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 Appendices2E, 3D, 5A, and 5B. (2) All NPVs are calculated with a 6.52% discount rate. (3) Numbers may not add due to rounding.

5.2.3 Hydrogen Blending

As mentioned in Chapters 3.6.1 and 3.7, the Company continues to evaluate the blending of hydrogen at its existing and future natural gas-fired power stations. In order to demonstrate the impact hydrogen blending could have on CO2 intensity, the Company conducted a high-level evaluation of the impacts of hydrogen blending on each primary Portfolio. This evaluation assumes that the Company could begin blending 10% hydrogen at capable natural gas-fired power stations beginning in 2028, and increasing to 30% by 2032. As seen in Figures 5.2.3.1 through 5.2.3.4 below, blending of hydrogen would have an immediate positive impact on carbon intensity levels which would continue throughout the Planning Period.

[24] NPV is a way to show how much an investment is worth throughout its lifetime and shown in today's dollars.

Figure 5.2.3.1: Hydrogen Blending – REC RPS Only with EPA Portfolio

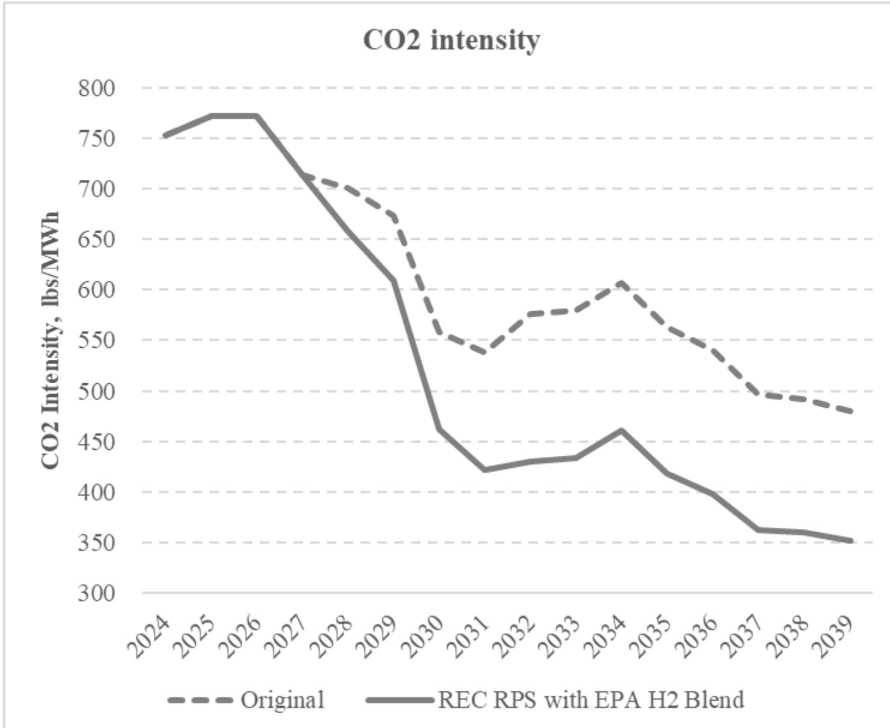


Figure 5.2.3.2: Hydrogen Blending – REC RPS Only without EPA Portfolio

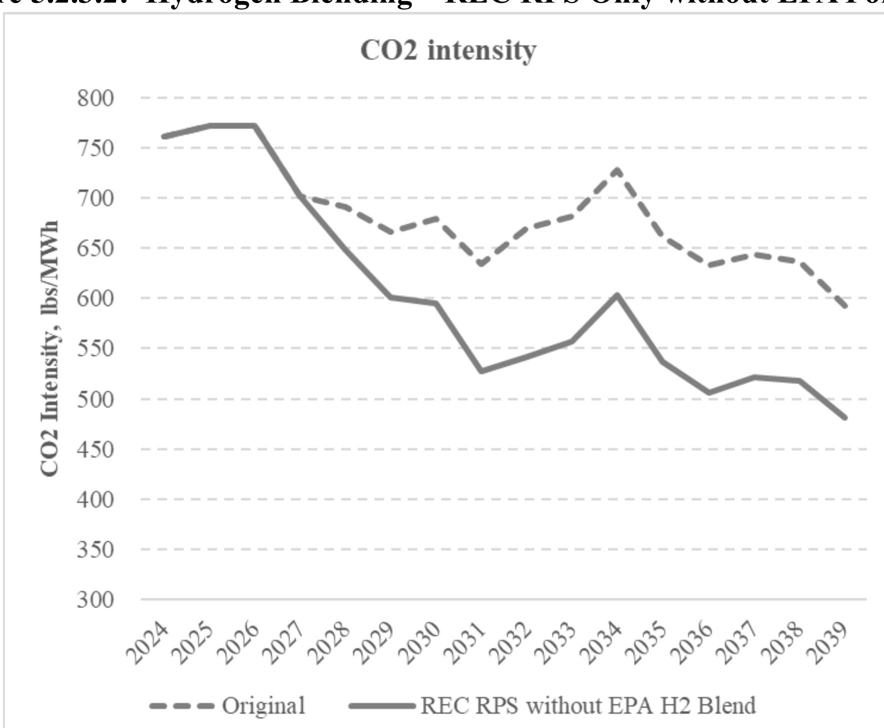


Figure 5.2.3.3: Hydrogen Blending – VCEA with EPA Portfolio

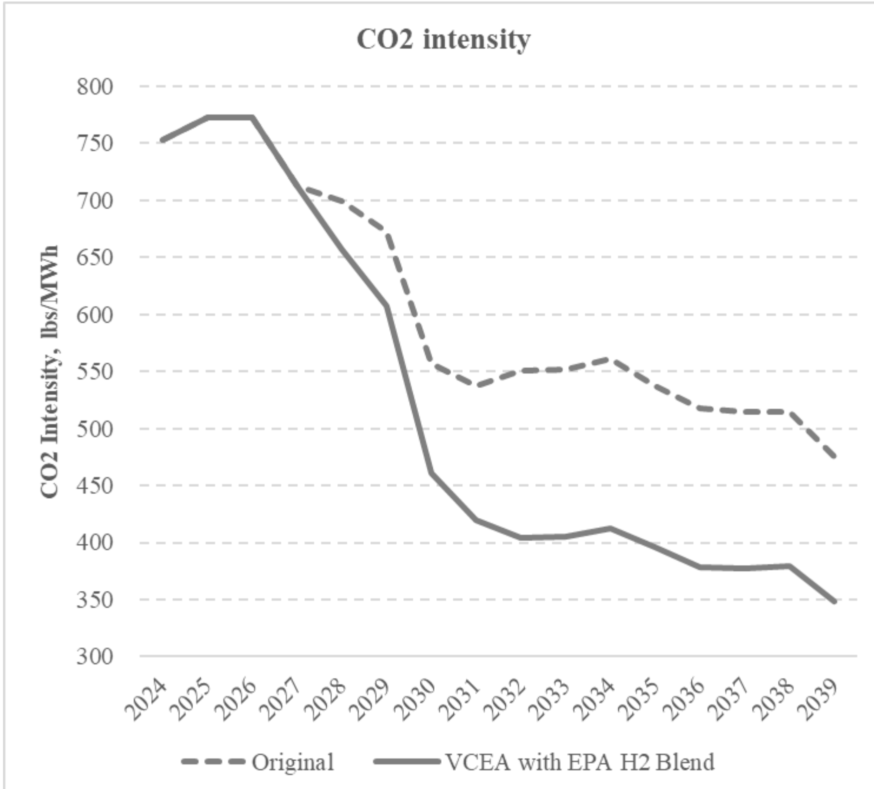
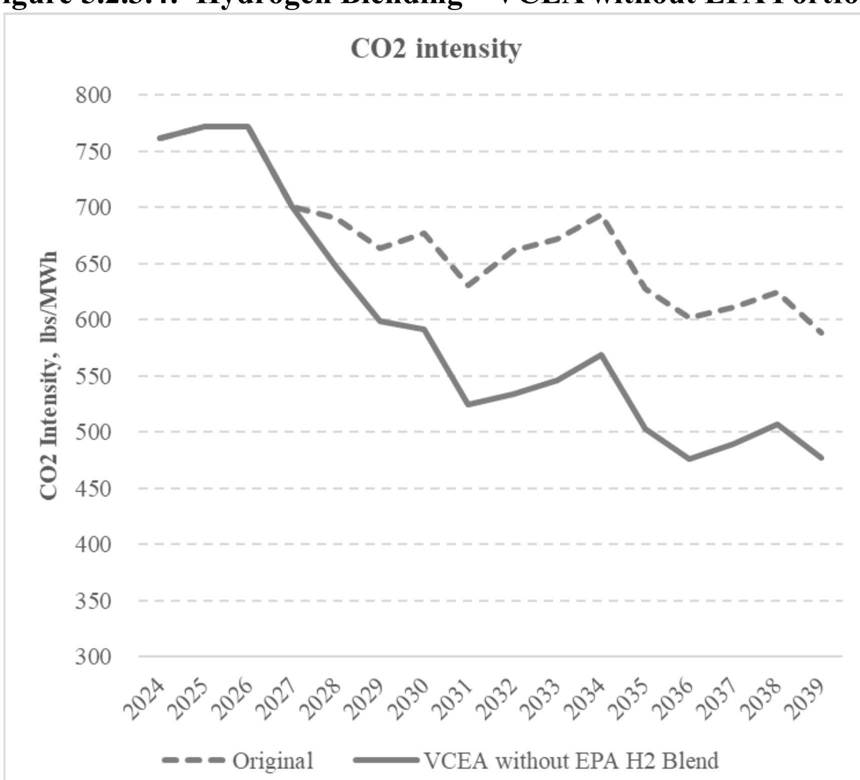


Figure 5.2.3.4: Hydrogen Blending – VCEA without EPA Portfolio



5.3 Sensitivity Analyses

The Company conducted several sensitivity analyses for this 2024 IRP 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. As discussed above, all Portfolios utilized the 2024 PJM Derived Load Forecast. The Company used the same general methodology to create the high/low sensitivities as it did in the PJM Derived Load Forecast. The differences are that the high/low sensitivities use a variation on the Data Center Load Forecast and the EE adjustment to the load forecast. In the high load forecast sensitivity, the Company modeled that the Data Center Load Forecast would be 5% higher in the first year of the forecast growing in a linear fashion to be 20% higher than the PJM Derived Load Forecast by 2039. Additionally, the Company modeled that EE savings would be half of the forecasted amounts. This resulted in a high load forecast sensitivity which starts out 1.5% higher than the PJM Derived Load Forecast in the first year, moving to 11.5% higher by 2039.

Stakeholder Process Highlight: The Company received feedback from stakeholders regarding running a sensitivity on the load forecast that includes higher and lower ranges for the load forecast. The Company included this sensitivity as described in this section.

The low load forecast sensitivity used the same general methodology as in the high load forecast sensitivity, with the exception that the Data Center Load Forecast was reduced by 5% in the first year proceeding in a linear fashion to a 20% reduction. EE savings were increased by 50%. This resulted in a low load forecast sensitivity which was symmetrical to the high load forecast sensitivity, being 1.5% lower than the PJM Derived Load Forecast in the first year, moving to 11.5% lower by 2039. The Company also ran a sensitivity using the 2024 Company Load Forecast. Figure 5.3.1 shows the results of these sensitivities.

Figure 5.3.1: 2024 Plan Sensitivities on Load Forecast

	PJM Load Forecast (VCEA with EPA Portfolio)	PJM High Load Forecast	PJM Low Load Forecast	Company Load Forecast
NPV Total ($B)	102.9	123.0	83.1	104.3
Approximate CO_2 Emissions from Company in 2039 (Metric Tons)	19.3	31.8	16.8	19.9
Solar (MW)	12,210	12,210	12,210	12,210
Wind (MW)	3,460	3,460	60	3,460
Storage (MW)	4,100	4,000	4,100	4,200
Nuclear (MW)	1,340	1,340	-	1,072
Natural Gas Fired (MW)	5,934	5,934	4,666	5,934
Retirements (MW)	-	-	-	-

Next, the Company ran input variations on the VCEA with EPA Portfolio to show the effect on NPV using a range of possible costs. The first sensitivity used different commodity price forecasts. 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. See Appendix 5B for a description of these forecasts and the interrelated nature of these commodity prices.

The Company also ran a sensitivity that increased and decreased the projected capital construction costs of different resources by 10%.

The Company worked with the NC Public Staff to conduct a sensitivity analysis with different annual solar and storage limits as directed by the NCUC Order for the 2023 IRP. This sensitivity, the NCUC Directed Sensitivity, models a variation of the VCEA with EPA Portfolio, in which solar and storage build limits are ramped up over the course of the 15-year planning period. For solar, the model begins building new solar in 2029 at a build limit of 1,020 MW/year, ramping to 1,500 MW/year in 2033, and 2,040 MW/year beginning in 2037. For storage, the model begins adding new storage in 2028 at a build limit of 350 MW/year, ramping to 550 MW/year in 2033 and 700 MW/year in 2037. Figure 5.3.2 shows the summarized NPV results of this group of sensitivities and Figure 5.3.3 shows the results of the NCUC Directed Sensitivity.

Figure 5.3.2: 2024 Portfolio Sensitivities on Fuel, Capital Costs and High Solar/Storage

Sensitivities (VCEA with EPA Portfolio)	NPV Total ($B)
VCEA with EPA Portfolio	102.9
High Fuel	110.0
Low Fuel	96.1
High Capital Construction Costs	105.6
Low Capital Construction Costs	100.4
NCUC Directed Sensitivity	102.0

Figure 5.3.3: NCUC Directed Sensitivity

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2025	-	-	-	-	-	-	-	2,352	-
2026	-	-	-	-	-	-	-	3,200	-
2027	-	-	-	-	-	-	-	2,300	-
2028	-	-	-	-	300	-	-	2,800	-
2029	591	429	45	-	300	-	-	2,800	-
2030	591	429	66	-	250	944	-	2,500	-
2031	552	468	75	60	350	-	-	2,900	-
2032	552	468	87	-	350	1,268	-	2,300	-
2033	1,032	468	96	-	550	818	-	2,300	-
2034	1,032	468	99	800	550	818	-	2,600	-
2035	1,032	468	102	-	550	818	-	2,500	-
2036	1,032	468	102	-	550	1,268	-	2,300	-
2037	1,572	468	105	-	700	-	-	3,000	-
2038	1,572	468	108	-	700	-	268	3,300	-
2039	1,572	468	105	2,600	700	-	268	3,300	-
TOTAL	**11,130**	**5,070**	**990**	**3,460**	**5,850**	**5,934**	**536**	**40,452**	

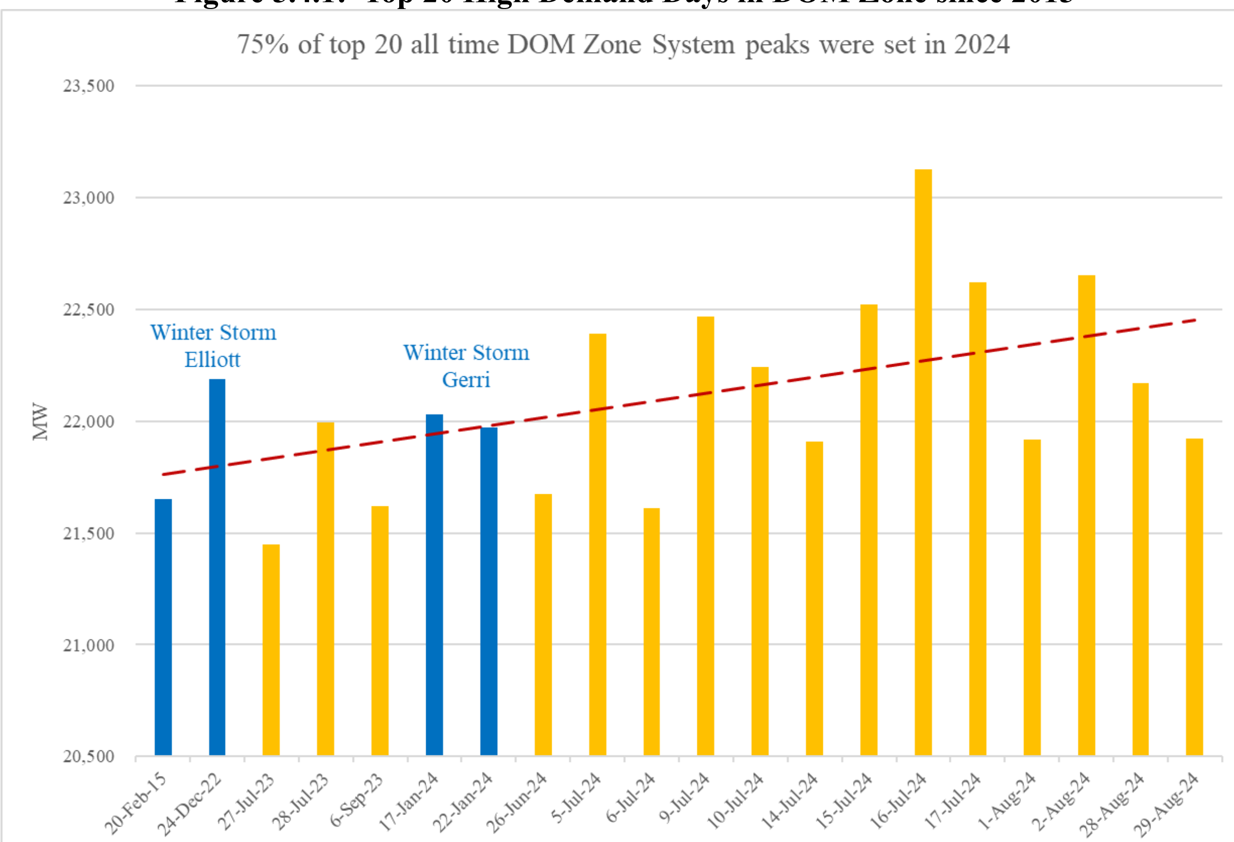
Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units

5.4 Extreme Weather Analysis

> **Stakeholder Process Highlight**: The Company received feedback from stakeholders regarding including an analysis on extreme weather. As a result, the Company performed this analysis on extreme weather.

The Company models normal weather for planning purposes. However, 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. Extreme weather can cause demand to spike. Figure 5.4.1 shows periods of high demand associated with extreme weather events since 2015. Recent extreme weather events impacting both the Company's service territory and other utilities across the country have highlighted the need to plan for these events in a manner that ensures the reliability of the generation, transmission, and distribution systems.

Figure 5.4.1: Top 20 High Demand Days in DOM Zone since 2015



For instance, in December 2022, Winter Storm Elliott caused a rapid 29-degree drop in temperature and a resulting spike in load during a long holiday weekend. Generators across the PJM system experienced a high number of forced outages due to gas supply shortages and plant equipment issues, among other reasons. Due to the spike in demand and forced outages, PJM implemented emergency procedures on December 23 and December 24, 2022.

Winter Storm Elliott underscored the need for backup fuel and sufficient ancillary commodities (*e.g.*, more than the typical clear-sky supply of ammonia or demineralized water). Finally, it demonstrated the risk of relying too heavily on market purchases or PJM Day Ahead awards during extreme weather.

Dispatchable resources, especially during the winter and extreme winter events, are needed to meet customer demand. Indeed, Table 5.4.2 demonstrates that nuclear, gas-fired, oil-fired, and coal-fired units, along with demand response, were essential to reliable operations during Winter Storm Elliott.

Table 5.4.2: Comparison of Actual Capacity of Generation Units during Winter Storm Elliott versus Summer Capacity Values

Fuel	Actual Capacity (MW)	Summer Capacity (MW)
Biomass	133	153
Coal	3,382	3,684
Gas	3,988	5,368
Hydro	278	2,124
Nuclear	3,489	3,348
Oil	3,662	3,824
Solar	2	1,228
Wind	12	12
DR	160	153

Accordingly, the Company conducted a sensitivity analysis to test the VCEA with EPA Portfolio under an extreme weather scenario. 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 2024 Load Forecast Report.[25] In order to utilize this forecast, the VCEA with EPA Portfolio was locked in PLEXOS, the modeling software utilized for the 2024 IRP, and the load forecasts for the years 2028 and 2035 were replaced with the higher 90/10 PJM load forecast. The 90/10 load forecast increased summer and winter peaks (*i.e.*, approximately 1,700 MW for summer peaks and as high as approximately 3,200 MW for winter peaks), as well as the hourly energy requirements. The model was given the same resources as the VCEA with EPA Portfolio but was required to dispatch hourly based on the higher 90/10 load forecast. This extreme weather scenario tested the robustness, in regards 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 VCEA with EPA Portfolio would

[25] PJM Interconnection, L.L.C., *PJM Load Forecast Report* (Jan. 2024), available at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx.

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 1,200 MW of capacity purchases in 2028 and an additional 1,100 MW of capacity purchases in 2035. In total, 4,500 MW of capacity purchases would be needed to meet an extreme weather scenario in 2028 and 4,400 MW of capacity purchases would be needed in 2035. These purchase amounts exceed the Company's annual capacity purchase limit of 3,300 per year. 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.

Despite the significant resource build in the VCEA with EPA Portfolio, the extreme weather scenario showed unserved energy of 1.8 MW in hour ending 18 on July 29, 2028. This unserved energy represents a risk of load shedding that could disrupt customers and businesses. It should be noted that these results are in modeling space where the model has perfect foresight of outages, generation, and peak load and should be read as indicative of an unacceptable system situation. It shows a potential near term (*i.e.*, 2028) vulnerability of the system to serve load in an extreme weather situation showing the importance of capacity and energy additions to the system as soon as they are available.

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 VCEA with EPA Portfolio, 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 5,000 MW of dispatchable generation (advanced CCs and simple cycle CTs) and 268 MW of new nuclear generation. Without these new resources, particularly those that can dispatch at any time day or night, the model would likely see significant energy shortages in both winter and summer.

One key takeaway of this extreme weather analysis is that the risk of unserved energy due to a higher than expected load forecast is actually greatest in the near term, before new resources can be completed. The addition of more dispatchable resources beginning in 2030, helps ensure that a higher than expected load forecast does not result in unserved energy needs. The changes to PJM's capacity market have incentivized 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 15-year cash flow analysis focused on coal-fired, biomass-fired, and large CC generation facilities under market conditions. The Company evaluated 15-year cash flows under three Portfolios using two commodity price forecasts, one of which considers the EPA environmental regulations and one that does not. 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 15 years based on the snapshot in time when the analysis was conducted. The results of the 15-year cash flow analysis are included in Figure 5.5.1.

Figure 5.5.1: 15-year cash flow retirement analysis

Units	REC RPS Only Without VCEA	VCEA Without EPA	VCEA With EPA	Est. T&D Impact
Clover 1 - 2	$346	$345	$496	$0
Mt Storm 1 - 3	$1,404	$1,391	$164	$62
Virginia City Hybrid Energy Center	$280	$275	$276	$0
Altavista	$51	$51	$86	$0
Hopewell	$49	$49	$86	$0
Southampton	$52	$51	$88	$0
Rosemary	$46	$47	$108	$0
Bear Garden	$883	$877	$1,204	$0
Brunswick	$2,358	$2,344	$3,253	$0
Chesterfield 7 - 8	$386	$382	$669	$0
Gordonsville 1 - 2	$277	$276	$425	$0
Greensville	$3,094	$3,077	$4,147	$3
Possum Point 6	$946	$941	$1,389	$0
Warren	$2,414	$2,399	$3,253	$136

Note: "Est. T&D Impact" represents the approximate transmission and distribution upgrades that would be necessary to support the unit retirement. This avoided cost is not included in the NPVs shown.

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 endogenously the timing of unit retirements. The Company presents these results as part of the 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 fifteen-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 2024 IRP 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 VCEA with EPA Portfolio.

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

6.1.1 Dominion Energy's EJ Policy

In 2018, the Company adopted an EJ policy, which commits to making environmental justice considerations part of our everyday decision-making as we work to deliver reliable, affordable, and increasingly clean energy to our 2.7 million customers in Virginia and North Carolina. Under this policy, project development teams are required to consult with the Company's dedicated EJ specialists who implement EJ reviews for all major projects, regardless of whether doing so is required for permitting or other regulatory approvals.

Stakeholder Process Highlight: The Company received feedback from Stakeholders requesting more detailed information on the Company's EJ process. Therefore, the 2024 IRP includes more information about how the Company considers EJ in the context of energy infrastructure development as well as a generic evaluation of potential environmental impacts relative to different types of power generation facilities.

EJ reviews begin as early in the project development cycle as feasible; the first step is to conduct a screening using data published by the U.S. Census Bureau, to identify potentially disadvantaged or marginalized segments of the community near a specific site or set of alternative sites. The results of the initial screening inform the project development team's planning. This includes consulting with outreach and communications staff to put in place enhanced outreach efforts targeted to solicit meaningful feedback from communities that might otherwise be unaware of or unable to participate in the planning and permitting process. This also includes collaborating with permitting experts on the project development team to identify the regulatory framework (*i.e.*, required permits and approvals) for a project, and working with the team to ensure agency permitting requirements are met, and where needed, to put in place mitigation and monitoring plans to avoid or minimize potential environmental impacts.

As community engagement and permitting efforts unfold, typically in parallel, any feedback from the community is considered by the Company and, to the best of our ability, presented to the permitting agency to aid in the agency's decision-making process. Permitting agencies typically also have their own public participation process, during which they can hear input directly from potentially affected communities. The Company works closely with all appropriate federal, state, local and tribal agencies, including an employee dedicated to tribal outreach, to mitigate environmental impacts through the required permitting, approval, or consultation processes.

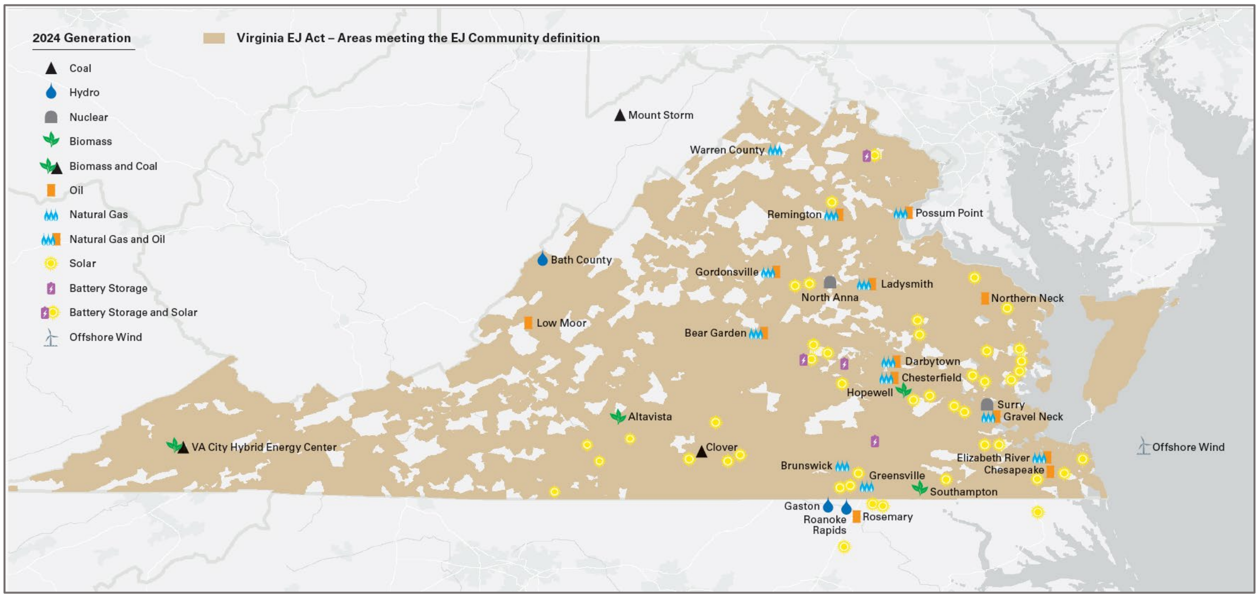
Information regarding the Company's comparison of the environmental justice consequences of constructing and/or operating different types of power generation resources contemplated by 2024 IRP modeling exercises is provided in Appendix 6A.

6.1.2 The Virginia Environmental Justice Act

The Virginia Environmental Justice Act ("VEJA") sets the policy of Virginia to promote EJ, ensuring the fair treatment and meaningful involvement of every person—regardless of race, color, national origin, income, faith, or disability—regarding the development, implementation, or enforcement of any environmental law, regulation, or policy.

Draft EJ guidance released by the Virginia Department of Environmental Quality in March 2023 concluded that applying VEJA definitions resulted in 53% of the total geographic area and 59% of the population lived in an area of the Commonwealth that met the definition of an EJ community. A 2024 study conducted by the Company, using updated census data and boundaries, concluded applying VEJA definitions resulted in 78% of the total geographic area and 89% of the population lived in an area of the Commonwealth that met EJ community definitions. With such a large proportion of the Commonwealth defined through the VEJA in 2021 as an EJ Community, avoidance is not possible. Figure 6.1.2.1 below shows the Company's generation resources along with the geographic areas that met the definition of EJ community in 2024.

Figure 6.1.2.1: VEJA EJ Community Map with the Company's Generation Resources



Stakeholder Process Highlight: During the Stakeholder Process, feedback was received to include this map (Figure 6.1.2.1) with facility locations.

6.1.3 Considering Environmental Justice

Generally, when considering environmental justice, one evaluates: the type of project or program at issue; where it will occur; what type of environmental impacts are likely; if any impacts, whether they are significantly negative or adverse; and, whether there are environmental justice communities that might suffer the adverse environmental impacts of the proposed activity.

The transition to a clean energy future requires substantial development of new infrastructure, which has the potential to affect surrounding communities. Under the current federal and state level standards of environmental protection, a fully permitted power generation or delivery facility of any kind operating in compliance with all applicable permitting conditions, regulations, and laws will not cause significant adverse health effects to any community, including EJ populations. Also important is the makeup and values of any affected community; whether a community views certain elements of a project as detrimental or beneficial in light of all factors and circumstances is bound to vary as each project and community is unique. The Company believes the presence of EJ communities should not exclude an area from energy development.

A reliable and affordable energy grid is essential to a healthy environment for any community, as are the economic development opportunities contingent upon the same. The public need for new infrastructure and the potential harm done by selecting a "no action," more costly, or less reliable alternative must be weighed against the possible outcomes for local communities resulting from any proposed project.

The Company believes whether a proposed action promotes EJ is best evaluated on a case-by-case basis, informed by the location of the project in question and project-specific characteristics. The Company has established an EJ review process for evaluating its specific projects and programs consistent with relevant laws and regulations. Based on this, the Company presents the results of these project-specific review processes in the relevant proceedings before the SCC, such as in its applications to construct new generating facilities or new or rebuilt transmission lines and will do so as appropriate in relevant proceedings before the NCUC.

6.1.4 A Just Transition to Clean Energy

As discussed in Chapter 5.5, the Company has not made any decision regarding the retirement of any current generating unit in the 2024 IRP. If such decisions were made, for example in 2045, the process for communicating such decisions in Va. Code § 56-599 C will be followed. At that time, we would plan for the transition of displaced employees to clean energy fields and other roles within the utility. We need to attract, retain, and retrain employees for careers that could span different technologies, and we are working toward those goals.

The Company's Education Assistance Program provides 100% reimbursement of eligible tuition costs, up to $7,500 per calendar year, for active, full-time, and part-time union and non-union employees who are scheduled to work at least 1,000 hours per year. This program can help employees gain the education they need and want to transition to clean energy jobs.

Stakeholder Process Highlight: Feedback was received from stakeholders regarding Just Transition. This section addresses Just Transition, with employee retraining resources.

Employees and customers are not the only stakeholders affected by the retirement of fossil fuel facilities. As with the loss of any industry, closing a plant can affect the economy, the environment, and the community in the surrounding areas. The Company will engage with state and local leaders about the effects of such closures, as required by Va. Code § 56-599 C. We also are committed to ongoing support of the communities where we have worked, and hope to continue to work, for many years. For example, we demonstrate that commitment through increased focus on clean energy construction on brownfield sites, leading to continued tax payments after fossil fuel facility retirements.

6.2 Customer Education

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, 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 Facebook® 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/user/DomCorpComm.
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/news.

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.

Online Energy Calculators

The Company is committed to helping customers save on their energy bills and provides saving tips and a "Lower My Bill Guide" on the Company website. Home and business energy calculators are provided as well to estimate electrical usage for homes and business facilities. The calculators help customers understand specific energy use by location and discover new means to reduce usage and save money. For customers considering the environmental impact of transportation choices, a calculator is offered to compare emissions and cost savings of cars side-by-side with more efficient hybrid or all-EVs. The energy calculators are available at:
https://www.dominionenergy.com/home-and-small-business/ways-to-save/energy-saving-calculators.

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 in an effort help prepare students for tomorrow's workplace. 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 July 2024, the Company has nine customer locations in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 168 MW. As July 2024, 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.

Appendix 1: 2024 IRP Stakeholder Process Report

Dominion Energy Virginia and North Carolina

2024 Integrated Resource Plan (IRP) Stakeholder Process Report

Background

In 2023, the Virginia General Assembly enacted legislation (the "Legislation") that, among other things, 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]

While the Company had previously conducted stakeholder sessions that included discussions regarding the IRP, this was the first time it had implemented a stakeholder process in support of the 2023 Legislation. To ensure the 2024 Dominion Energy Virginia and North Carolina Integrated Resource Plan Stakeholder Process ("Stakeholder Process") was conducted efficiently, fairly, and effectively, the Company retained the expertise of professional third-party facilitators from the McCammon Group (the "Facilitators"). By retaining the McCammon Group, the Company aimed to foster a collaborative environment where diverse perspectives and feedback could be heard and considered for integration into the Company's 2024 IRP ("2024 IRP").

In this Stakeholder Process Report ("Report"), Dominion Energy details the Stakeholder Process and its efforts to engage a diverse array of stakeholders throughout the development of its 2024 IRP. This includes a thorough account of the various stages of the Stakeholder Process, the opportunities employed to gather input, and the initiatives designed to ensure broad participation. This Report also includes a narrative of feedback the Company received, both quantitative and qualitative, that was included in the 2024 IRP.

It is important to note that this Report, while reflective of the Company's efforts, is the work of the Company and does not reflect the review or endorsement of any of the participating stakeholders.

Objectives

Consistent with the requirements of the Legislation, the Company's objectives for the Stakeholder Process were 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 IRP, including the IRP's development methodology, modeling inputs, and assumptions.
- Provide the ability for the public to make relevant inquiries to the utility when formulating its IRP.

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

To achieve these objectives, Dominion Energy established a series of commitments to stakeholders that focused on encouraging broad participation and integrating diverse perspectives into the IRP. The aim was to create a collaborative framework that not only meets statutory requirements but also sets realistic goals for the Company's first IRP Stakeholder Process. The commitments to stakeholders were as followed:

- Provide multiple opportunities for stakeholder input during the IRP 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;
- Develop an IRP that meets all legislative, regulatory, and operational requirements, including maintaining 24x7x365 reliability; and
- Respond to questions relevant to the 2024 IRP provided they do not involve highly sensitive or confidential information.

Stakeholder Identification

The stakeholder list included participants in past IRP proceedings, staff of the Virginia State Corporation Commission ("SCC") and of the North Carolina Utilities Commission ("NCUC"); other local, state, and federal government officials; non-governmental organizations; tribes; nonprofit groups; military/defense sector; unions; businesses and large energy users; citizens, among many others.

As an additional step to ensure that all potential stakeholders had the opportunity to participate in the process, the Company posted public notices in 29 newspapers in Virginia and 18 newspapers in North Carolina:

Public Notice
Dominion Energy Virginia 2024 Integrated Resource Plan Stakeholder Process

Dominion Energy Virginia is seeking stakeholder input for the 2024 Integrated Resource Plan (IRP) and will be hosting meetings over the next several months to gather comments from interested parties.

If you are interested in participating in this stakeholder process, please send: your name, contact number, business or organization name, and a brief description of your interest in the IRP to the following email address.

DEVIRP@DominionEnergy.com

Public Notice

Dominion Energy North Carolina 2024 Integrated Resource Plan Stakeholder Process

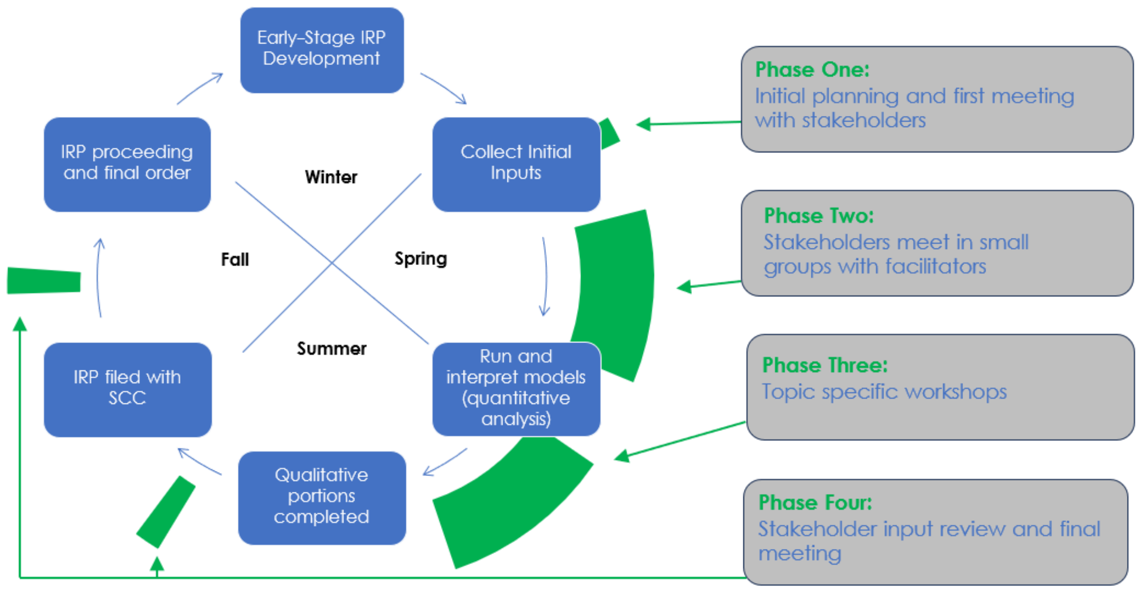
Dominion Energy North Carolina is seeking stakeholder input for the 2024 Integrated Resource Plan (IRP) and will be hosting meetings over the next several months to gather comments from interested parties.

If you are interested in participating in this stakeholder process, please send: your name, contact number, business or organization name, and a brief description of your interest in the IRP to the following email address: *devirp@devirp.dominionenergyinfo.com*

In total, the Company had engaged approximately 200 individual stakeholders by the final stakeholder meeting.

Stakeholder Engagement Opportunities

Dominion Energy collaborated with the Facilitators to establish a stakeholder process that ensured every stakeholder had multiple opportunities to provide feedback and make relevant inquiries. The process was divided into four phases:



Phase I: Kick-off meeting that provided all stakeholders with a foundation of knowledge on the IRP before more in-depth conversations in subsequent phases.

Phase II: Small group meetings where the Company presented the same information at each meeting and stakeholders had candid conversations with the Facilitators. These sessions focused on gathering more detailed inputs on the IRP, the stakeholder process generally, and served as an opportunity for stakeholders to make inquiries of the Company.

Phase III: Three Topic-specific workshops for more in-depth and detailed conversations, based on feedback and areas of interests expressed by stakeholders.

Phase IV: One meeting to review the collective input and recommendations of stakeholders incorporated by the Company into the IRP and another meeting scheduled for after the IRP is filed for an overview of the 2024 IRP.

For all but the final meeting in Phase IV, the Company offered participants an in-person option at the Company's headquarters in Richmond, Virginia and a virtual meeting option. Details about each meeting can be found below.

As an additional measure for ensuring stakeholders had ample opportunities to provide feedback and make inquiries, the Company established a dedicated website and email address. The website (https://devirp.dominionenergy.com)[2] provided information on the IRP and the Stakeholder Process, including meeting dates, Stakeholder Process information, summaries and presentation materials. The website also served as a repository for a question and answer ("Q&A") section featuring questions from stakeholders and the Company's responses. It also included a feedback form for stakeholders to submit their information, input, and ideas at any time, as well as to ask questions and receive answers from the Company. The dedicated email address also allowed stakeholders to directly communicate with the Company.

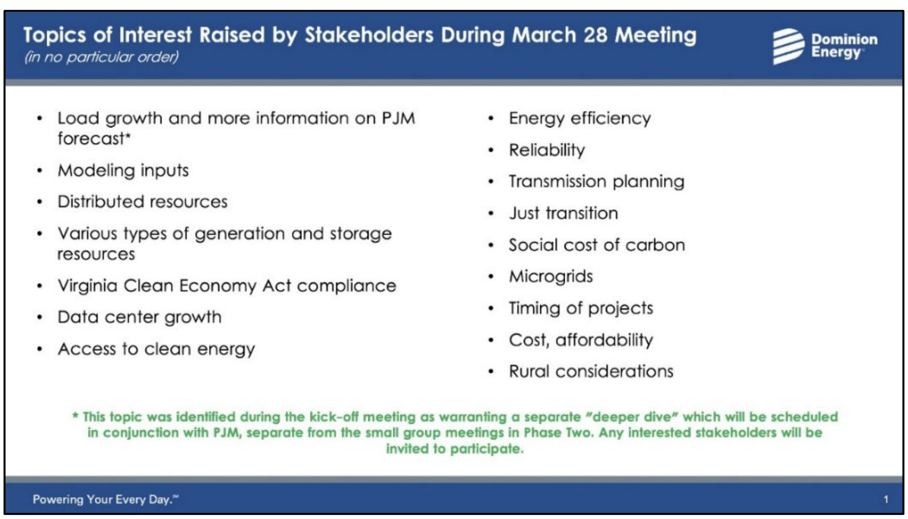
Phase I: Kick-Off Meeting

On March 28, 2024, Dominion Energy held its first stakeholder meeting to discuss its 2024 IRP and introduce the Stakeholder Process. This kick-off meeting marked the start of a comprehensive process aimed at gathering information, input, and ideas on the IRP.

With approximately 43 attendees joining in-person and 82 joining virtually, Dominion Energy provided an overview of the goals and objectives of the new Stakeholder Process. In addition, the Company emphasized the importance of capturing diverse input, meeting all legislative, regulatory, and operational requirements, and providing multiple opportunities for stakeholder engagement.

A representative from PJM Interconnection, LLC ("PJM") provided an overview of PJM's role and key statistics of the organization. The PJM representative also detailed the load forecasting process and the various factors that are taken into consideration, including end-use characteristics, weather conditions, calendar/solar data, and economic indicators.

To gather initial insights from participants, the Facilitators detailed their roles in the Stakeholder Process and asked stakeholders about their priorities and what stakeholders hoped to achieve. The following table summarizes the topics raised during the Kick-Off Meeting:



[2] The presentations associated with the Stakeholder Process, the Phase II meeting summaries, and the Q&As can be found on the website.

Dominion Energy concluded the meeting by providing a summary of the next steps in the Stakeholder Process, including the scheduling of small-group sessions and the posting of materials on the stakeholder website. Participants were encouraged to actively engage in the process, with future sessions designed to be more interactive and focused on dialogue and exchange.

Phase II: Small Group Meetings

Given the broad interest in Dominion Energy's Stakeholder Process, the Company aimed to ensure that every participant had an equal opportunity to provide input and make relevant inquiries. To achieve this goal, the Company organized small group meetings moderated by the Facilitators, where stakeholders could offer candid feedback. Based on the Facilitators' recommendations, these meetings were limited to 20 participants each.

To offer flexibility to interested stakeholders, each group was given multiple meeting dates to choose from, including a make-up date, as well as options for in-person and virtual participation. In total, the Company hosted ten small group meetings in May 2024. Staff from both the SCC and the NCUC were invited to each meeting.

At each small group meeting, the Company presented the same information, including overview information about the IRP, timeline for the IRP and Stakeholder Process, and key considerations for the 2024 IRP. These presentations lasted approximately 15 minutes to maximize the time stakeholders had to provide feedback during the meeting.

After the presentation, the Facilitators initiated the conversation by presenting each small group meeting with six questions:

1. What information would you like to share regarding planning for 24x7x365 reliability over the next 15 years?
2. What information would you like to share about affordability for customers?
3. What would you like to tell DEV and DENC about technologies, resources, and infrastructure to meet customer needs?
4. What ideas do you have regarding the 2024 IRP (including modeling inputs and assumptions)?
5. Is there anything else you would like to share about your (or your entity's) energy priorities?
6. What questions do you have?

The following table shows the dates and times, along with the summary of the responses to each small group meeting:

Small Group Meeting #1 May 1, 11:00 am – 1:00 pm 10 RSVPs (3 in-person, 7 virtual)	**Small Group Meeting #2** May 6, 9:00 am – 11:00 am 19 RSVPs (12 in-person, 7 virtual)
Small Group Meeting #3 May 7, 1:00 pm – 3:00 pm 7 RSVPs (2 in-person, 5 virtual)	**Small Group Meeting #4** May 9, 9:00 am – 11:00 am 4 RSVPs (2 in-person, 2 virtual)
Small Group Meeting #5 May 9, 1:00 pm – 3:00 pm 6 RSVPs (2 in-person, 4 virtual)	**Small Group Meeting #6** May 10, 9:00 am – 11:00 am 4 RSVPs (0 in-person, 4 virtual)
Small Group Meeting #7 May 16, 9:00 am – 11:00 am 6 RSVPs (1 in-person, 5 virtual)	**Small Group Meeting #8** May 16, 1:00 pm – 3:00 pm 10 RSVPs (6 in-person, 4 virtual)
Small Group Meeting #9 May 17, 9:00 am – 11:00 am 8 RSVPs (5 in-person, 3 virtual)	**Small Group Meeting #10** May 30, 1:00 pm – 3:00 pm 9 RSVPs (0 in-person, 9 virtual)

Phase III: Topic Specific Workshops

Dominion Energy held three topic-specific workshops, based on themes, areas of interest, feedback and questions expressed by stakeholders during the Stakeholder Process. Each workshop included a brief presentation on the specific topic followed by time for stakeholders to ask questions and provide feedback directly to the Company through a conversation with the Facilitators. Additionally, subject matter experts from Dominion Energy were available to answer questions or share additional details.

Workshop 1 - Modeling

On June 3, 2024, the Company held its first workshop, focusing on modeling inputs and assumptions for the 2024 IRP. This topic was scheduled first because the Company needed to start modeling later that month, making it the last opportunity to receive any remaining stakeholder feedback that could influence the modeling. The initial invitation for this workshop was emailed to stakeholders on May 21, followed by a reminder on May 28. The presentation was sent to stakeholders on May 30. Out of approximately 172 invitations, approximately 15 attendees joined in-person and 36 joined virtually.

During this workshop, Dominion Energy reintroduced the Company's IRP modeling process using PLEXOS software and discussed specific considerations for the 2024 IRP. Of note, changes included PJM's updated Effective Load Carrying Capability ("ELCC") criteria, new environmental regulations, and as recommended by several stakeholders, non-normal weather analysis, and new energy efficiency savings targets beyond 2025.

Dominion Energy also presented several potential IRP plans for illustrative and discussion purposes with stakeholders. The presentation concluded with a discussion of potential sensitivities. The Facilitators then opened the floor for discussion and questions.

Workshop 2 – Environmental Justice

The Company held its second workshop, focused on environmental justice ("EJ") and just transition, on June 12, 2024. The initial invitation for this meeting was emailed to stakeholders on May 31, followed by a reminder on June 5. The presentation was sent to stakeholders on June 10. Out of approximately 176 invitations, approximately 12 attendees joined in-person and 35 joined virtually.

During this workshop, Dominion Energy introduced the Company's EJ commitments and efforts, such as demographic screenings to identify EJ communities, extensive employee training on EJ principles, and direct engagement with tribal leaders.

Dominion Energy also discussed the current qualitative approach to addressing EJ in IRPs and highlighted stakeholder input received to date. Finally, the Company provided an overview of the "Just Transition" to a clean energy grid, emphasizing that economic health and environmental sustainability can coexist.

To conclude the meeting, the Company invited stakeholders to provide input on how EJ should be qualitatively incorporated into the 2024 IRP, noting that the Company aims to balance the impacts and benefits of energy infrastructure, including renewables, while maintaining energy affordability and reliability.

Workshop 3 - Reliability

The Company held its third and final workshop, focused on reliability, including load forecast, energy efficiency and transmission, on July 24, 2024. The initial invitation for this meeting was emailed to stakeholders on June 27, followed by a reminder on July 10. The presentation was sent to stakeholders on July 23. Out of approximately 199 invitations, approximately 24 attendees joined in-person and 58 joined virtually.

During the workshop, Dominion Energy reintroduced PJM's load forecast and the load forecast methodology used for the Dominion Zone and Dominion Load Serving Entity. The Company discussed factors influencing the load forecast, including energy efficiency and demand-side management. Additionally, Dominion Energy provided an overview of the data center market, highlighting the data center forecast process and growth drivers.

Dominion Energy highlighted its achievements in energy efficiency, reporting significant customer bill savings, water savings, and CO_2 avoidance, among other benefits. The presentation concluded with insights into the IRP Transmission Line Import/Export Study, which evaluated the transmission network's capability under various contingencies, emphasizing that the energy market is not designed to rely on imports as a baseload resource.

The Facilitators then opened the floor for discussion and questions.

Phase IV: Stakeholder Input Review

On August 23, 2024, the Company held its Phase IV stakeholder meeting to review the collective input received from stakeholders throughout the 2024 IRP stakeholder process. The initial invitation for this meeting was emailed to stakeholders on August 8, followed by reminders on August 14 and August 20. The presentation was sent to stakeholders on August 22. Out of approximately 205 invitations, approximately 12 attendees joined in-person and 58 joined virtually.

Dominion Energy began with a brief update on the Stakeholder Process and an overview of how stakeholder input will be reflected in the IRP once filed. The Company then proceeded with a detailed summary of the key differences between the 2023 IRP and the 2024 IRP, highlighting specific changes to PJM's load forecast and ELCC criteria, as well as the incorporation of new environmental regulations. In addition, an overview of the technologies being considered for the 2024 IRP was provided.

While not final at that time, Dominion Energy provided an overview of potential modeling sensitivities and build plans extending to 15 years. The Company discussed possible scenario ranges for the load forecast, fuel, and construction costs, and explained that the Company would also be including a scenario regarding non-normal or extreme weather. Regarding build plans, Dominion Energy described the inclusion of a Least Cost Plan for comparison in the IRP that meets only applicable carbon regulations and the mandatory RPS requirements. The Company also explained that there would be modeling plans that are Virginia Clean Economy Act ("VCEA") compliant and that meet the RPS requirements and the development targets for solar, wind, and energy storage resources both with and without the environmental regulations.

As part of the presentation, Dominion Energy addressed the incorporation of EJ and reliability considerations within the IRP. The Company's approach to EJ in the 2024 IRP would include a more detailed description of Dominion Energy's EJ process, a potential evaluation of impacts across various power generation facilities, a map applying the Virginia Environmental Justice Act ("VEJA"), and a commitment to the Just Transition for employee retraining.

Dominion Energy also provided an update on grid-enhancing technologies ("GETs") and advanced conductors, noting that this year's IRP would include an assessment of the potential application of GETs and advanced conductors.

The meeting concluded with a facilitated conversation for clarifying questions and feedback.

The final stakeholder meeting for the 2024 IRP stakeholder process is scheduled for Friday, October 18 at 10:00 am. At this meeting, the Company plans to provide an overview of its filed 2024 IRP. A recording of the presentation will be posted to the Stakeholder Process website.

Summary of Incorporated Stakeholder Input

Dominion Energy received feedback from stakeholders regarding all aspects of the IRP, both quantitative and qualitative. Dominion Energy carefully considered all feedback and questions received, and incorporated them into its IRP where possible, while taking into consideration complex modeling constraints, the need for complete data, and operational and regulatory requirements.

During the Stakeholder Process, the Company received requests from stakeholders to include specific technologies in the 2024 IRP modeling such as long duration storage, tidal wave, hydrogen, small modular reactors ("SMRs") and geothermal as well as carbon capture and sequestration ("CCS"). The Company continues to evaluate these technologies and will consider them for future IRPs. The 2024 IRP includes SMRs in the model, along with a qualitative discussion on the role of SMRs in meeting load demand and the transition to clean energy.

Throughout the Stakeholder Process the Company also received feedback to include more information in the 2024 IRP regarding the impacts of carbon emissions and the social cost of carbon. As a result, the Company included more information on carbon emissions and carbon intensity in the 2024 IRP.

Energy efficiency was another area where the Company received feedback. In particular, stakeholders indicated they would like to see energy efficiency savings increasing throughout the modeling plan, rather than a flatline of savings. They also requested more detailed information in the qualitative portion regarding the energy efficiency programs the Company offers and the outreach efforts to inform customers about those programs. While the VCEA prescribes energy efficiency targets through 2025, as it relates to energy efficiency in the modeling, the Company modeled energy efficiency savings that align with the Company's proposal in the SCC's pending target-setting proceeding for 2026 to 2028. Modeling beyond 2028 is based on proposed targets with a reasonable increase based on savings potential. This approach aligns with stakeholder feedback as the Company incorporated increased energy efficiency into the modeling for all years of the planning period and described the energy efficiency programs it offers in an appendix to the 2024 IRP.

Many stakeholders provided feedback regarding the load forecast. Stakeholders indicated that they would like to see multiple ranges of the load forecast at both higher and lower levels as compared to the base assumption of the PJM Load Forecast information. The Company has considered this feedback and modeled a sensitivity that includes different scenario ranges for the plus and minus part of the sensitivity, higher and lower load, in particular the 5, 10 and 20 percent levels of variation.

Stakeholders requested that the Company show scenarios that included non-normal or extreme weather. As a result, the Company included an extreme weather analysis in the 2024 IRP.

EJ was a common theme in stakeholder feedback. In particular, stakeholders requested more qualitative information in the IRP regarding how the Company considers EJ in its processes. The 2024 IRP includes a more detailed description of the Company's project-specific EJ process. The

IRP also includes more information about how the Company considers EJ in the context of energy infrastructure development, as well as a generic evaluation of potential environmental impacts relative to different types of power generation facilities. All types of power generation considered in the IRP are included: solar, wind, battery storage, fossil, and nuclear facilities. This information is provided in a table format in the 2024 IRP. The Company created a map applying the VEJA EJ Community to the entire Commonwealth, which was shown to stakeholders during the Environmental Justice Topic Specific Workshop. Stakeholders requested this map, along with the addition of facility locations. This map, with facility locations, is included in the 2024 IRP, along with a description of the methods used to create the map. Lastly, feedback was received regarding Just Transition, and the 2024 IRP includes a section related to the Just Transition, with employee retraining resources.

Reliability was a key focus in all stakeholder meetings, and energy efficiency and load forecast feedback were incorporated into modeling and sensitivities. Qualitative feedback regarding reliability was largely focused on GETs and advanced conductors, and their inclusion in the IRP. The 2024 IRP includes information on the potential application of GETs and advanced conductors.

Stakeholder Input Case

During the Stakeholder Process, stakeholders requested a case that contemplated VCEA compliance, including no new natural gas-fired generation and retirements of carbon-emitting generation units by 2045. In response, the Company modeled a plan with these inputs (see **Figure 1: Stakeholder Input Case**).

By modeling this Stakeholder Input Case, the Company does not submit that it is practicable, realistic, or workable.

- In order to avoid unserved energy without natural gas additions, the Company first has to assume an unrealistic amount of capacity is available to import annually, 5000 MW.

- It should be noted that dramatically increasing imports 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.

- The Stakeholder Input Case would also increase the amount of solar energy and energy storage built to an infeasible amount, which may have the unintended consequence of making all solar and energy storage projects more difficult to site by prompting additional land use restrictions at the local level, if not outright bans.

- Additionally, the Stakeholder Input Case would assume additional offshore wind beyond the three projects the Company is now constructing or developing and twice as many SMRs. The incremental cost of adding these very large projects within the 15-year planning window and more of them going forward is unrealistic.

- With regard to offshore wind, an incremental 2,600 MW would also likely create very significant coastal transmission siting challenges.

- With these important cautions, the Stakeholder Input Case and the assumptions that underlie it are presented below.

This stakeholder-requested case utilizes the commodity price forecast that includes the suite of federal environmental regulations that the Environmental Protection Agency ("EPA") recently finalized that affect the electric utility sector. The implications of these new environmental standards include potential retirements of fossil-fueled generators, which could in turn impact future fuel availability and prices, capacity prices, and energy prices, commonly referred to as commodity complex. However, those new environmental standards all face legal challenges at this time, and the outcomes will be uncertain. This commodity price forecast assumes that environmental regulations in their current form as of May 2024 withstand the legal challenges as a whole.

The Stakeholder Input Case builds no additional fossil generation and assumes existing carbon emitting generation resources will retire by 2045 or will be in compliance with existing laws.

This Stakeholder Input Case includes building and buying significant incremental capacity to meet customer load over the next 15 years.

This Stakeholder Input Case includes increasing build limits as compared to the primary Portfolios included in the 2024 IRP, by:

- Doubling the amount of solar to 2,040 MW annually;
- Doubling the amount of storage to 700 MW annually;
- Doubling the amount of SMRs to 2 units annually;
- Adding another 2,600 MW of offshore wind to be built; and,
- Increasing capacity purchase limit to 5,000 MW per year.

In the Company's view, all of these incremental increases are infeasible.

Combining the incremental resources in this case with the like resources in the primary Portfolios, over the 15-year planning period, the Case includes 23.4 GWs of solar, 7.6 GWs of storage, 6.1 GWs of wind, almost 3 GWs of SMRs and requires that the capacity purchase limit be increased to 5,000 MW per year to meet customer need.

Figure 1: Stakeholder Input Case

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2025	-	-	-	-	-	-	-	2,352	-
2026	-	-	-	-	-	-	-	3,200	-
2027	-	-	-	-	-	-	-	2,300	-
2028	-	-	-	-	350	-	-	2,800	-
2029	1,611	429	45	-	450	-	-	2,700	-
2030	1,611	429	66	-	700	-	-	2,900	-
2031	1,572	468	75	60	700	-	-	3,100	-
2032	1,572	468	87	-	700	-	-	3,400	-
2033	1,572	468	96	-	700	-	-	4,100	-
2034	1,572	468	99	800	700	-	536	4,500	-
2035	1,572	468	102	-	700	-	536	4,600	-
2036	1,572	468	102	2,600	700	-	536	5,000	-
2037	1,572	468	105	-	700	-	536	4,800	-
2038	1,572	468	108	-	700	-	536	5,000	-
2039	1,572	468	105	2,600	450	-	268	5,000	-
Total	**17,370**	**5,070**	**990**	**6,060**	**7,550**	**-**	**2,948**	**55,752**	

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

Stakeholders have dedicated a significant amount of time to the Stakeholder Process through their participation, questions, and feedback. The Dominion Energy team working on the IRP sincerely thanks each stakeholder. Throughout this first Stakeholder Process, we have asked for your patience and understanding, and you have graciously provided both. We are grateful for your time, contributions, and the trust you have placed in us.

Conclusion

The Stakeholder Process for Dominion Energy's 2024 IRP not only demonstrates the Company's efforts to comply with the requirements of the Legislation, but it also signifies a deliberate step toward fostering collaboration in energy planning. This comprehensive process, initiated early in the IRP development phase, has successfully engaged and solicited feedback from a diverse range of stakeholders.

Through a series of structured phases, and the development of a website dedicated to the process, Dominion Energy has provided multiple opportunities for stakeholders to contribute information, input, and ideas, as well as to make relevant inquiries. Professional Facilitators from the McCammon Group have been engaged to support an efficient and effective process, allowing for candid and meaningful conversations and feedback.

Appendix 2A: Load Forecast Methodologies

The Company utilized the PJM DOM Zone Load Forecast as published in the 2024 PJM Load Forecast Report, dated February 2024, in the development of the 2024 IRP Portfolios. The PJM website contains information on the methods PJM used to develop this forecast.[1] PJM annually solicits information from each electric distribution company ("EDC") in PJM regarding significant future block load increases, including data centers, that are known to the EDC. For the 2024 load forecast, PJM again requested a 15-year data center forecast for the DOM LSE. As the EDC for the DOM Zone, the Company provided PJM the data center load forecast for certain cooperatives and retail choice[2] ("Choice customers").[3] Additional detail on the data center load forecast is provided in Section III. PJM then independently analyzed this information, incorporated the information into its annual forecast at its discretion, and developed a load forecast for all 22 load zones within the PJM footprint and published its report on the PJM website. The DOM Zone is one of these load zones.

I. PJM Derived Load Forecast for DOM LSE

In order to properly use the PJM Load Forecast for modeling purposes, Dominion Energy converted that forecast to the DOM LSE level. The DOM LSE Load Forecast is needed for modeling because the DOM LSE Load Forecast is comprised of demand of the Company's customers that the Company is obligated to serve, as compared to the entire DOM Zone, which includes customers served by other LSEs. The Company refers to this load forecast as the 2024 PJM Derived Load Forecast.

As explained further in the 2024 IRP Plan, due to tightening supply of energy and capacity against the backdrop of increasing demand, the Company's internal planning also includes consideration of generation resource adequacy for the entire DOM Zone.

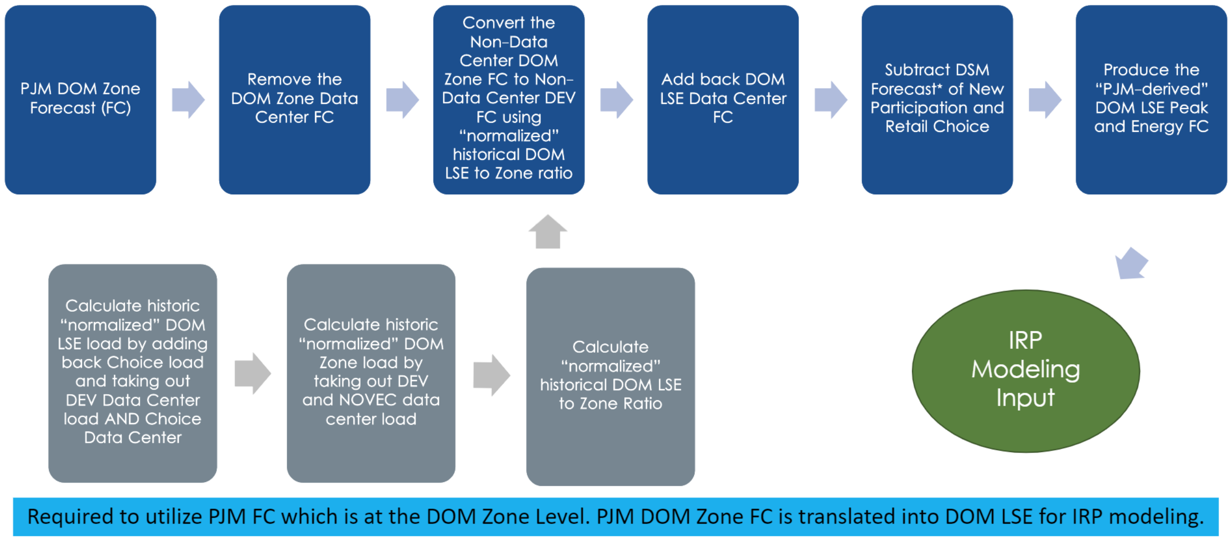
With this caveat, to prepare the PJM Derived Load Forecast for the DOM LSE, the Company used the following process as diagrammed in Figure 1 below.

[1] *See* PJM Interconnection, L.L.C., *Load Forecast Development Process*, available at https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

[2] Choice customers are customers within the Company's service territory who have chosen to purchase energy and capacity from third-party retail electric suppliers under Va. Code § 56-577.

[3] NOVEC also provided its data center forecast directly to PJM and the Company's submission excluded forecasted NOVEC data center load growth.

Figure 1: PJM DOM Zone Load Forecast conversion to DOM LSE Forecast flow chart

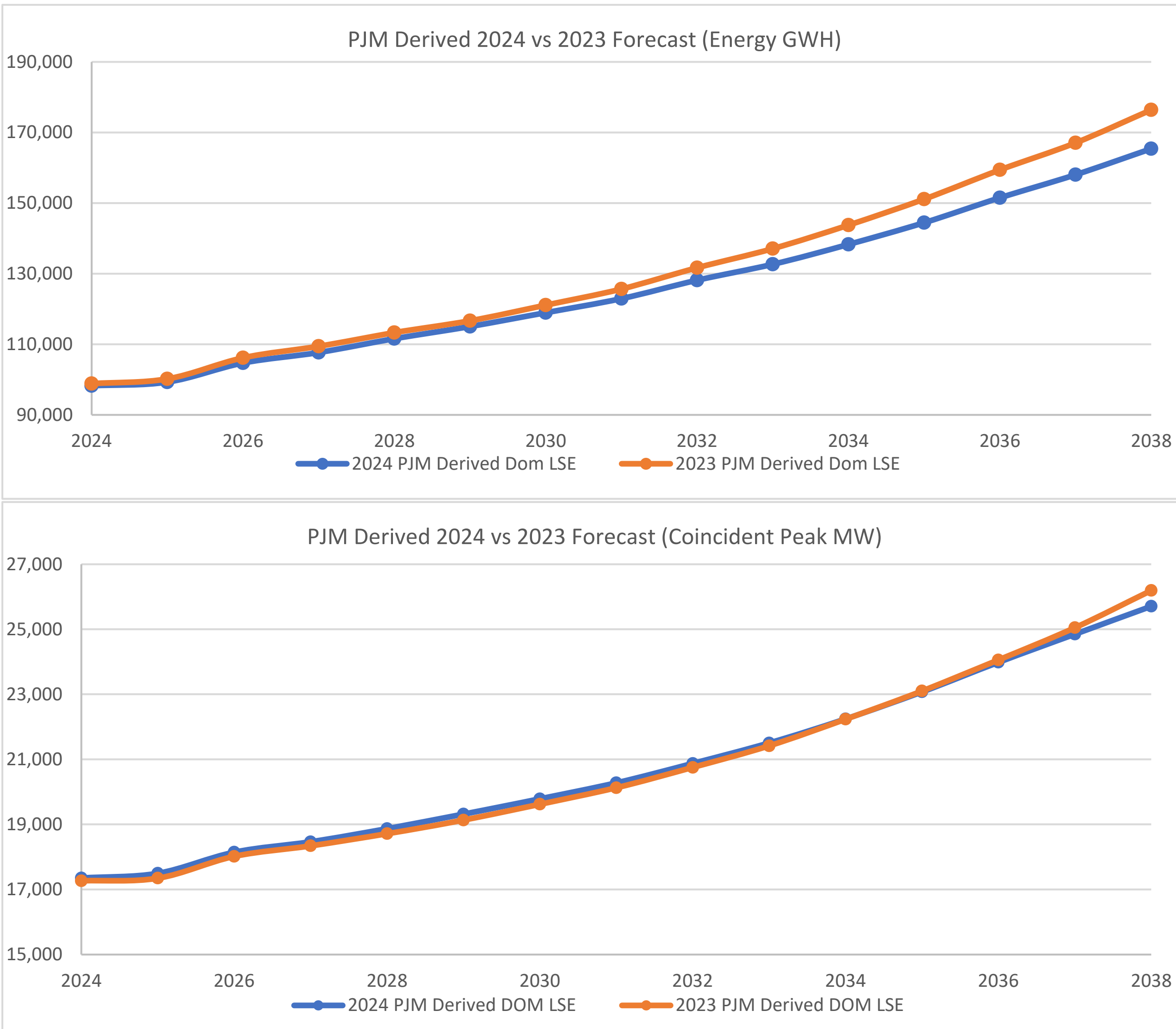


The Company first scaled down the PJM DOM Zone peak load and energy forecasts to the DOM LSE level, and then extended the forecast horizon. The Company completed this in two parts. First, the Company adjusted the forecast by taking out PJM's DOM Zone data center forecast and then applied a normalized historical DOM LSE-to-DOM Zone load ratio. The Company calculated the DOM LSE-to-DOM Zone ratio by using a five-year average (2019 to 2023) of DOM LSE-to-DOM Zone annual energy, excluding data centers. It should be noted that the DOM LSE-to-DOM Zone ratio continues to decline throughout the forecast horizon due to high data center growth outside the DOM LSE. This method of scaling down the PJM forecast ensures that the DOM LSE-to-DOM Zone ratios appropriately change in the forecast period.

The Company then added back the DOM LSE portion of the data center forecast and removed the Choice forecast. It is important to note that the data center forecast the Company incorporated into the PJM Derived Load Forecast is derived by PJM and includes only the DOM LSE data center forecast which does not include the forecast from NOVEC or other cooperatives in the DOM Zone. Finally, the Company removed incremental DSM to result in the PJM Derived Load Forecast used for the 2024 Plan.

Overall, the 2024 PJM Derived Load Forecast anticipates a 2.8% and 3.8% compounded annual growth rate ("CAGR") for the DOM LSE summer non-coincident peak ("NCP") demand and annual energy respectively, over the Planning Period (2025-2039). Over the same period, the 2024 Company Load Forecast predicts a 2.5% and 3.8% CAGR for the DOM LSE summer non-coincident peak demand and annual energy, respectively. Forecasts for both energy (MWh) and peaks (MW) are presented. Providing reliable power to customers means meeting their needs 24 hours a day, 7 days a week, 365 days a year. Accordingly, PJM and Dominion Energy not only forecast customers' annual and monthly energy needs but also winter and summer peaks, which are the times of highest customer demand. As shown in Figure 2 below, the 2024 PJM Derived Load Forecast coincident peak is very similar to the 2023 PJM Derived Load Forecast. This highlights that the changes in the DOM Zone Load Forecast from last year to this year have been driven by the projected growth in the cooperatives. The figure also shows that the 2024 PJM Derived Load Forecast for energy is slightly lower than the 2023 PJM Derived Load Forecast. Differences in the growth trajectory between coincident peaks and annual energy were due to changes in PJM modeling assumptions.

Figure 2: 2024 vs 2023 PJM Derived Load Forecast Coincident Energy and Peak



II. Company Load Forecast

The 2024 IRP also includes the Company's internally developed peak demand and energy forecast for the DOM LSE (*i.e.*, the Company Load Forecast). The Company ran a sensitivity on VCEA with EPA Portfolio replacing the PJM Derived Load Forecast with the Company Load Forecast. While the Company Load Forecast and 2024 PJM Derived Load Forecast are in general alignment, the Company continues to believe that its forecast is more appropriate to use than PJM's forecast. Because the Company forecasts sales and associated drivers at the customer-class level, the resulting forecast is better able to capture region-specific load characteristics. As an example, PJM's forecast incorporates DSM reductions but does not specifically incorporate Company DSM programs or future savings targets. While the Company attempts to account for future DSM savings targets when calculating the PJM Derived Load Forecast, it must do so without any regard for DSM already embedded in PJM's original DOM Zone forecast. As another example, while the Company has conducted a study to forecast EVs that is specific to its service territory, PJM has not been able to conduct such a detailed study for each of its load zones. Finally, converting the forecast from DOM Zone to DOM LSE entails complexities that are avoided by directly modeling the Company load, as is done within the Company Load Forecast.

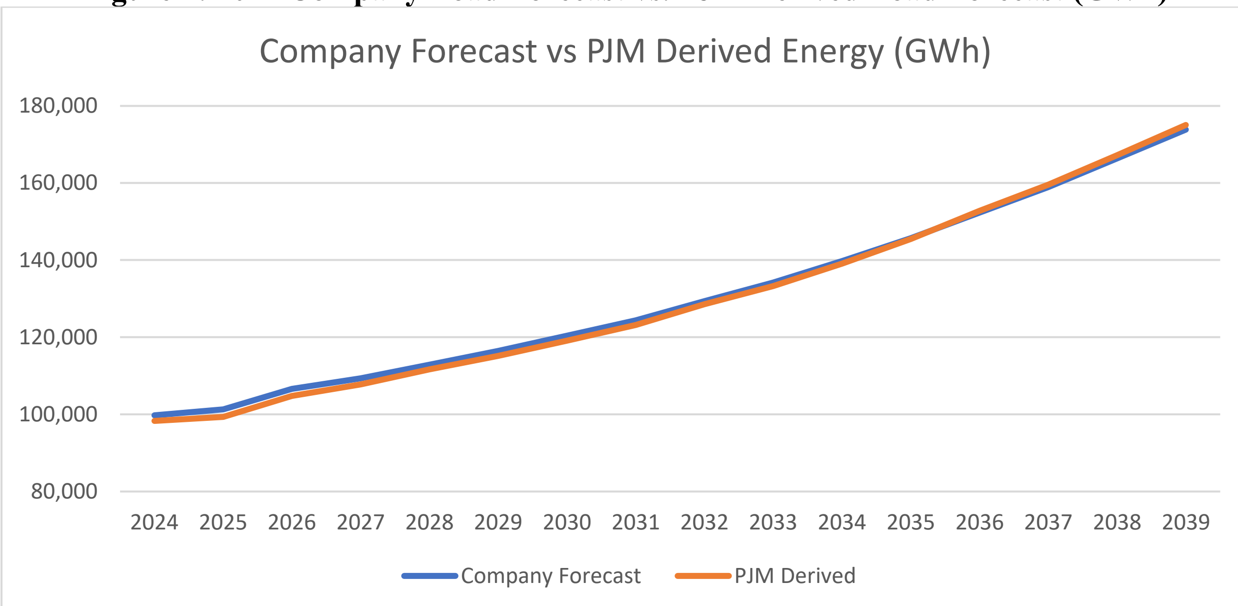
At a high level, the Company Load Forecast is prepared using Company sales data and DOM LSE peak and energy data. Separate sales models are created for residential, commercial, industrial, government, and other municipal customers. Data centers are forecasted separately from other commercial customers given the scope and distinctive nature of the industry (See Section III below). The resulting sales forecast is then converted into an energy forecast using an estimated loss factor. This is then followed by post-processing forecast adjustments for data centers, retail choice sales, DSM, distributed solar, and EVs. Finally, the peak forecast is derived from a detailed hourly model using historical weather simulation. Figure 3 below presents the 2024 Company Load Forecast NCP and annual energy.

Figure 3: 2024 Company Load Forecast

Year	Dom LSE Summer Peak Forecast (NCP) (MW)	Dom LSE Energy Forecast (GWh)
2024	18,023	99,731
2025	18,113	101,289
2026	18,720	106,575
2027	18,968	109,323
2028	19,332	112,837
2029	19,747	116,422
2030	20,276	120,386
2031	20,770	124,348
2032	21,270	129,332
2033	21,872	134,149
2034	22,538	139,710
2035	23,212	145,643
2036	24,017	152,288
2037	24,706	158,918
2038	25,541	166,346
2039	26,415	173,819

Despite the differences in methodology, the 2024 Company Load Forecast results are very similar to the PJM Derived Load Forecast, as shown below in Figure 4. Due to the methodological differences between the Company and PJM load forecasting, alignment of the resulting load forecasts is not guaranteed for reasons described earlier in this section.

Figure 4: 2024 Company Load Forecast vs. PJM Derived Load Forecast (GWh)



III. Data Center Load Forecast

Dominion Energy has over a decade of experience working with data center customers on a daily basis, and through these customer partnerships, has been trusted with customer and industry intelligence that informs the Company's Data Center Load Forecast. The Company's access to, and integration of, this real-world intelligence sets the Company's forecast apart from other forecasting models and approaches. Existing contracts with customers validate the Company's Data Center Load Forecast.

Dominion Energy provided PJM with a 15-year Data Center Load Forecast for the DOM LSE. If a wholesale cooperative within the DOM Zone requests the Company's assistance with data center forecasting in its service territory, the Company will assist that cooperative up to and including submitting a forecast on its behalf. Dominion Energy did submit forecasts in 2023 on behalf of two wholesale cooperatives. All other wholesale cooperatives submitted their own data center forecasts (*e.g.*, NOVEC provided its own forecast to PJM).

Data Center Load Forecast Methodology

Dominion Energy uses a systematic process, refined over the last several years, to develop the Data Center Load Forecast. First, Dominion Energy identified the largest and/or fastest growing data center customers within its service territory. The Company identified eight such data center customers, and all other data center customers were combined into a ninth segment. Second, Dominion Energy prepared a forecast for the nine data center customer segments described above using statistical methods and public and confidential customer information. These customer segment forecasts were combined into an overall forecast identified as the "high" forecast. This approach is conservative because it uses the customer segment forecast as the "high" forecast. The Company calculated an initial MWh forecast for the nine customer segments using a linear regression method. The Company then prepared three different demand forecasts for each customer segment resulting in 27 different demand models for the nine customer segments. Next, the Company applied customer intelligence to select the appropriate demand model for each customer segment. If none of the three models aligned with customer intelligence as to future business growth, then an adjusted growth curve was used (*e.g.*, a flat growth curve). The Company then used the historical monthly usage of demand to create the forecasted demand values by month within each year. The Company adjusted the initial MWh forecast by applying the historical industry average load factor to the selected model to derive the MWh forecast by segment. The final step taken was the removal of retail choice MWh. Third, the Company used historical metered data to develop six different statistical models of the overall industry. These six models were averaged to develop the "low" forecast. Finally, the Company took an average of the by-customer segment ("high") and aggregate ("low") forecasts to derive the "medium" scenario, which became the Company's official submission to PJM.

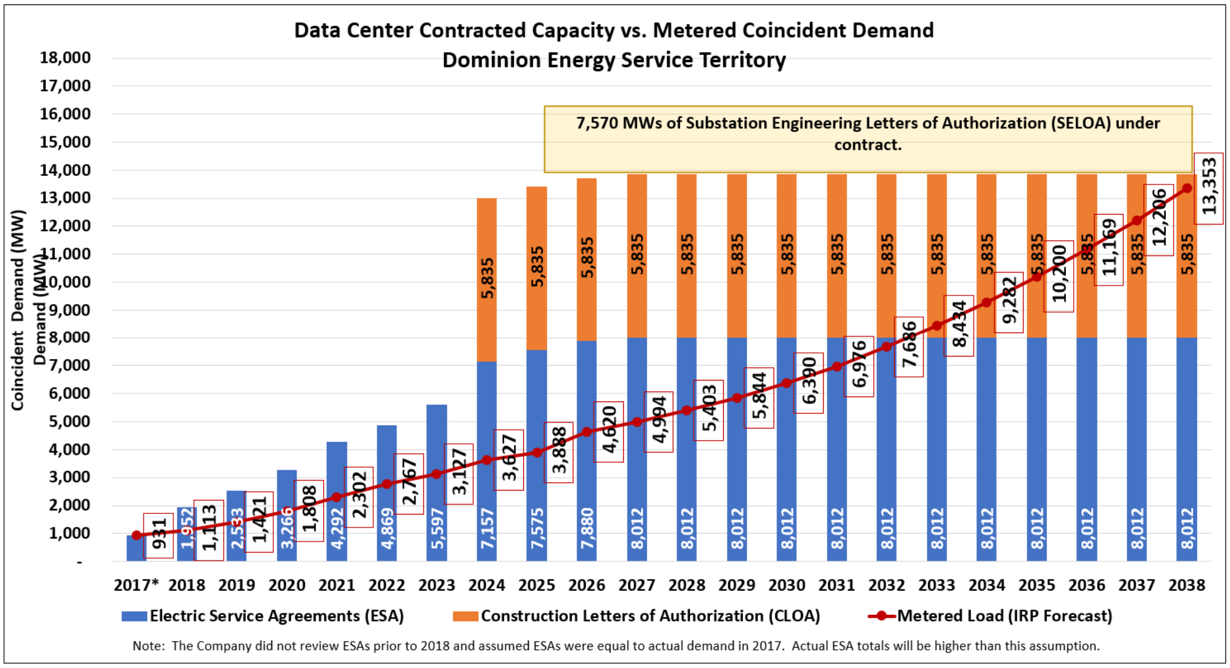
Dominion Energy works closely with data center customers early in their planning stages (typically three to seven years in advance of project initiation). Using customer-provided capacity requests, the Company's data center load forecast was broken down by county to develop an estimate of where future data center load growth would occur within the Company's service territory (*i.e.*, the DOM LSE).

The first contractual step is an engineering analysis contract. The second contractual step is a construction contract. The final step is an Electric Service Agreement ("ESA").

- Substation Engineering Letters of Authorization ("SELOAs") are contracts requesting the Company to begin the necessary engineering for new distribution and transmission infrastructure required to serve a new data center project. Should a customer cancel a project, it is obligated to reimburse the Company for its engineering time. As of July 2024, the Company has 7,570 MWs under contract.
- Construction Letters of Authorization ("CLOAs") are the contracts that enable construction of the required distribution and transmission infrastructure. Should a customer cancel a project, it is obligated to reimburse the Company for its investment to date. As of July 2024, the Company has 5,835 MWs under contract.
- ESAs are the contracts for electric service between the Company and a customer. Each contract is structured for an individual account. By signing an ESA, the customer is committing to consuming enough electricity annually to cover the Company's incremental cost of the distribution infrastructure. The contract also includes a minimum demand requirement. If the customer does not meet these obligations, then the customer is required to reimburse the Company for the amount the Company spent to serve the customer's expected demand. Many ESAs include ramp schedules in which the contracted MWs grow over the term of the agreement. Through 2032, the Company has 8,012 MWs contracted with data center customers through ESAs.

Figure 5 below depicts the Company's longer-term forecast (through 2038) and supporting customer commitments.

Figure 5: Data Center Contracted Capacity v. Metered Coincident Demand (through 2038)



IV. 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. As with data centers, a separate EV forecast was developed, and the corresponding incremental sales are added to the appropriate residential or commercial sales forecast as a post-modeling adjustment. The EV forecast was developed by Guidehouse, Inc. Figure 6 below shows the EV contribution to peak and energy forecast, respectively.

Figure 6: Electric Vehicle Contribution to Peak Demand and Annual Energy Forecast (MW)

Year	EV Contribution to Peak (MW)	EV Annual Energy (GWh)
2024	24	122
2025	58	293
2026	102	524
2027	161	823
2028	237	1,211
2029	333	1,699
2030	454	2,329
2031	598	3,069
2032	758	3,918
2033	928	4,805
2034	1,102	5,740
2035	1,277	6,704
2036	1,451	7,697
2037	1,620	8,633
2038	1,784	9,575
2039	1,942	10,496

V. 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 the overall demand and energy forecasts in the Dom LSE by subtracting SCC-approved and pending, when applicable (*i.e.,* currently under review by the SCC) DSM program participation from the Company's overall load forecast. The load forecasts in this 2024 IRP include a downward adjustment for EE. The EE adjustment to the forecasts can be broken down into two distinct categories. The first category consists of previously SCC-approved and EE programs that remain effective (*i.e.*, that are still producing savings), along with program forecasts of new incremental program participation including programs that recently have been approved by the SCC. The second category represents forecasted savings growth and is designed to meet (i) the Company's proposed 2026-2028 EE Savings Target reductions (currently under review in Case No. PUR-2023-00227); (ii) forecasted EE target reductions for 2029 and beyond; (iii) the GTSA requirement to propose $870 million in EE programs by 2028; and (iv) the requirement that at least 15% of EE costs are allocated to programs designed to benefit low-income, elderly, disabled individuals, or veterans.

This approach to meet the EE target reductions is a simplifying assumption used for modeling purposes only. The actual costs and benefits of future EE will be dependent upon many factors, including the ability of future vendors to deliver program savings at the fixed price, customer participation, and the effectiveness of the program to be administered at the forecasted price. Consistent with the Company's filing in Case No. PUR-2023-00227, the Company assumed that by 2028 the EE savings target of 2.72% of the 2019 VA Jurisdictional sales will be met.

Figures 7 and 8 identify the EE energy and coincidental capacity adjustments to the load forecasts used in this 2024 IRP, respectively. Values shown are at the utility generator and adjusted for line losses.

Figure 7: EE Energy Forecast Adjustment

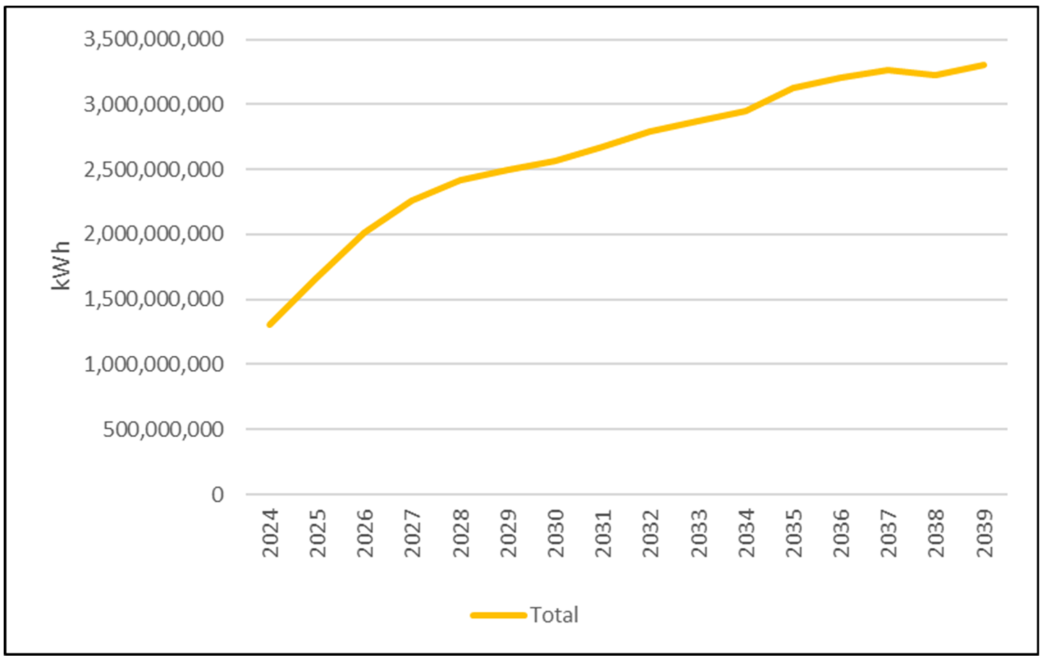
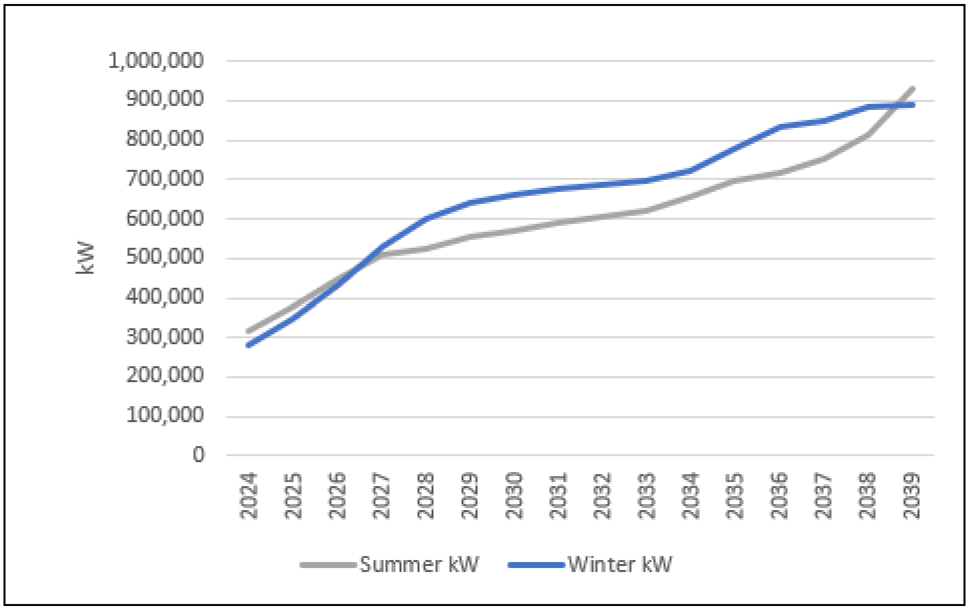


Figure 8: EE Coincident Peak Demand
Forecast Adjustment



VI. Retail Choice Adjustment to DOM LSE Load Forecast

The load forecasts in this 2024 IRP include a downward adjustment for Choice Customers. To develop this forecast the Company first identified the group of current Choice Customers. The Company then determined the annual energy for this set of customers over 2023. Finally, the Company shaped the total energy into hourly intervals using historic Choice Customer interval data.

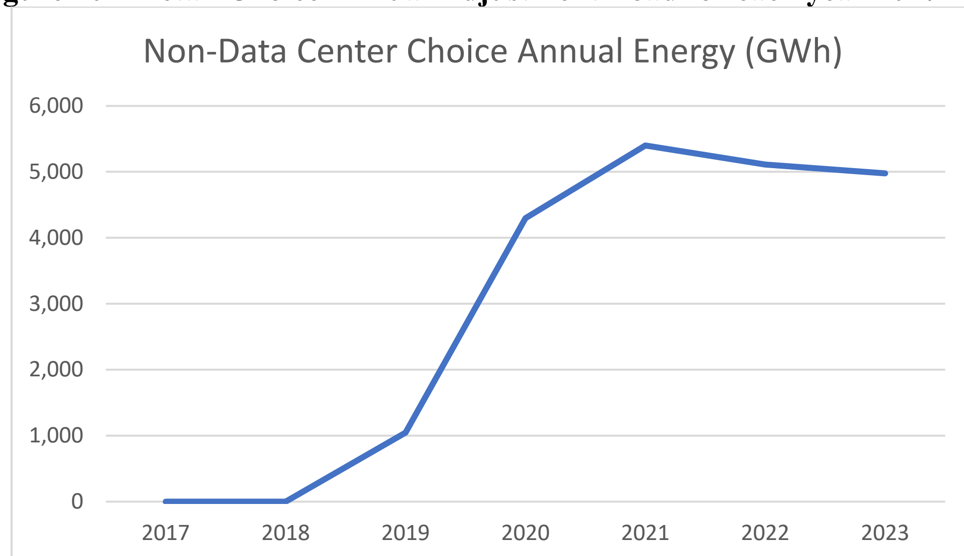
The summation of each customer's average annual energy and capacity use then formed the starting point for the Choice Customer forecast. Choice Customers whose most recent period demand exceeded five MW and who seek to return to the Company for energy supply service are also required to provide the Company with five-year written notice of intention to return to Company service. The Company, to date, has not received such written notice, and has not made any assumptions regarding customers returning to the Company. Figure 9 below identifies the Choice Customer peak demand and energy forecast adjustment in this 2024 IRP.

Figure 9: Retail Choice Annual Adjustment for each year 2025-2039

Estimated Retail Choice Sales (GWh)	Estimated Retail Choice Coincident Peak (MW)
3,920	601

Due to the uncertain nature of customer migration in or out of Choice, the Retail Choice Adjustment is held constant throughout the forecast period. Figure 10 below highlights the complex history of Choice Customer load over time.

Figure 10 – Retail Choice Annual Adjustment Load for each year 2017-2023



VII. Methodology

The Company uses two econometric models to forecast sales, energy, and peak demand. The first is a customer-class-level sales model with an end-use orientation ("Sales Model") and the second is a system-level hourly load model ("Peak and Energy Models"); both models were estimated over a rolling 15-year historical period.

Sales Model

The Sales Model incorporates separate monthly sales equations for residential, non-data center commercial, industrial, public authority, street and traffic lighting, and wholesale customer classes. The monthly sales equations are specified in a manner that produces estimates of heating load, cooling load, and non-weather sensitive load. The sales equation comprises total sales for all customer classes except for residential, where a use per customer forecast is developed and then multiplied by a customer count forecast to derive total residential sales. The residential sales equation also relies on an algorithm that dynamically adjusts forecasted appliance saturation and usage based on historical trends. These historical trends are determined based on 2023 EIA surveys.

Peak and Energy Model

The Company's Energy Model is derived from the sales model using a regression model utilizing a historical relationship between monthly sales and monthly energy.

The Company's Peak Model is comprised of 24 separate equations, one for each hour of the day, with adjusted Company loads as the dependent variable. Prior to estimating the Peak Model equations, historical hourly loads are adjusted by subtracting data center load and adding back historical distributed solar generation and retail choice load. This adjustment is performed to ascertain the true load, rather than a load that is masked by these factors.

The Peak Model equations include a non-weather sensitive base demand variable, as well as a detailed specification of weather variables. The weather variables include interactions between both current and lagged values of temperature, humidity, wind speed, sky cover, and precipitation for five weather stations. The Peak Model also employs indicator variables to capture monthly, day of week, time of day, holiday, and other seasonal effects, as well as unusual events such as hurricanes that produce widespread outages and the influence of COVID-19. Once the peak forecasts are derived, the data center forecast is added back as well as adjustments for distributed solar, retail choice, incremental DSM load, and incremental EV load.

Economic and Demographic Assumptions

The economic and demographic assumptions that were used in the Company Load Forecast models were supplied by Moody's Analytics ("Moody's"), prepared in March 2024, and are included as Appendix 4M. Figure 11 below summarizes the economic variables used to develop the Company's sales forecast.

Figure 11: Major Assumptions for the Sales and Peak and Energy Models

	2024	2029	Compound Annual Growth Rate (%) 2024 - 2029
DEMOGRAPHIC:			
Customers (000)			
Residential	2,468	2,631	1.29%
Commercial	253	265	0.95%
Population (000)	8,764	8,923	0.36%
ECONOMIC:			
Employment (000)			
State & Local Government	556	564	0.31%
Manufacturing	249	245	-0.33%
Government	745	753	0.20%
Income ($)			
Per Capita Real disposable	54,006	59,047	1.80%
Price Index			
Consumer Price (1982-84=100)	313	349	2.22%
VA Gross State Product (GSP)	605	668	2.00%

Note: (1) "State & Local Government" = State (Commonwealth of Virginia) + Local (County + Municipalities)
(2) "Government" = State (Commonwealth of Virginia) + Local (County + Municipalities) + Federal Employment (Non-Military)

Explanatory Variable Comparison

The Company relies on Virginia economic explanatory variable forecasts supplied by third parties in the development of its load forecast. The supplier of these explanatory variable forecasts for the 2024 Company Load Forecast was Moody's.

Net Metering Forecast

The net metering forecast process is based on the three-parameter Bass Diffusion Model ("BDM"). The BDM is fitted to actual net metering customer data to determine the three parameters of the BDM, which are the coefficient of innovation, the coefficient of imitation, and the ultimate market potential. The BDM model then determines the net metering customer forecast, which is then translated into energy and peak using historical data.

Wholesale Power Sales

Parties to whom the Company has committed to providing full requirement wholesale power sales are included in the Company's Load Forecast.

Results

The results of the Company's forecast are represented in **Figure 3: 2024 Company Load Forecast.** DOM LSE is forecasted to be a summer-peaking system. DOM LSE peak and energy requirements are both estimated to grow annually at an approximate CAGR of 2.5% and 3.8%, respectively, throughout the Planning Period.

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
2012	29,174	28,927	7,849	10,496	277	2,011	78,735
2013	30,184	29,372	8,097	10,261	276	1,984	80,174
2014	31,290	29,964	8,812	10,402	261	1,956	82,685
2015	30,923	30,282	8,765	10,159	275	1,981	82,385
2016	28,213	31,366	8,715	10,161	253	1,856	80,564
2017	29,737	32,292	8,638	10,555	258	1,609	83,088
2018	32,139	33,591	8,324	10,761	260	1,607	86,681
2019	31,439	35,296	7,302	10,645	263	1,580	86,524
2020	32,670	32,911	6,503	11,073	261	1,439	84,856
2021	31,598	35,203	6,716	10,740	245	1,570	86,071
2022	31,114	39,518	6,399	11,018	232	1,543	89,823
2023	31,046	43,636	5,384	11,069	209	1,550	92,894
2024	31,479	47,587	5,537	11,029	238	1,534	97,404
2025	31,722	49,997	5,376	10,820	231	1,527	99,674
2026	31,889	55,095	5,356	10,769	231	1,518	104,859
2027	32,114	57,638	5,332	10,730	231	1,518	107,564
2028	32,536	60,972	5,313	10,726	232	1,531	111,309
2029	32,864	64,106	5,261	10,659	231	1,512	114,632
2030	33,406	67,636	5,222	10,623	231	1,505	118,624
2031	33,932	71,178	5,184	10,597	231	1,499	122,622
2032	34,610	75,728	5,163	10,617	232	1,509	127,859
2033	35,178	79,875	5,112	10,579	231	1,488	132,463
2034	35,918	84,833	5,075	10,571	231	1,481	138,111
2035	36,626	90,183	5,039	10,564	231	1,481	144,124
2036	37,496	96,225	5,019	10,587	232	1,507	151,065
2037	38,068	102,199	4,968	10,548	231	1,505	157,519
2038	38,780	108,809	4,932	10,539	231	1,517	164,808
2039	39,405	114,993	4,897	10,530	231	1,531	171,588

Note: Historic (2012 - 2023); Projected (2024 - 2039)
Appendix 2B-1 has been provided with the 2024 Company Load Forecast instead of the 2024 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
2012	27,672	28,063	6,235	10,370	269	1,958	74,568
2013	28,618	28,487	6,393	10,134	267	1,934	75,833
2014	29,645	29,130	6,954	10,272	253	1,906	78,160
2015	29,293	29,432	7,006	10,029	266	1,930	77,956
2016	26,652	30,537	6,947	10,033	245	1,803	76,217
2017	28,194	31,471	6,893	10,429	250	1,556	78,794
2018	30,437	32,752	6,598	10,633	252	1,555	82,228
2019	29,829	34,472	5,591	10,517	254	1,530	82,194
2020	30,969	32,159	4,872	10,924	253	1,393	80,570
2021	29,968	34,464	4,980	10,590	238	1,519	81,759
2022	29,474	38,750	4,888	10,868	225	1,496	85,701
2023	29,431	42,931	3,924	10,880	201	1,503	88,870
2024	29,847	46,878	4,093	10,834	229	1,483	93,364
2025	30,093	49,297	3,933	10,622	223	1,473	95,642
2026	30,264	54,404	3,833	10,564	223	1,464	100,751
2027	30,489	56,954	3,805	10,538	223	1,464	103,472
2028	30,909	60,290	3,684	10,520	224	1,477	107,104
2029	31,235	63,423	3,920	10,457	223	1,458	110,717
2030	31,773	66,950	3,857	10,418	223	1,452	114,673
2031	32,293	70,485	3,894	10,392	223	1,446	118,733
2032	32,963	75,027	3,707	10,414	224	1,455	123,791
2033	33,523	79,164	3,830	10,374	220	1,435	128,548
2034	34,256	84,111	3,701	10,378	223	1,428	134,097
2035	34,954	89,444	3,477	10,360	223	1,428	139,886
2036	35,813	95,467	3,481	10,384	224	1,453	146,822
2037	36,374	101,422	3,512	10,344	223	1,452	153,327
2038	37,075	108,010	3,445	10,335	223	1,463	160,551
2039	37,689	114,172	3,353	10,327	223	1,477	167,240

Note: Historic (2012 - 2023); Projected (2024 - 2039)
Appendix 2B-2 has been provided with the 2024 Company Load Forecast instead of the 2024 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
2012	1,502	864	1,614	126	8	53	4,167
2013	1,567	885	1,704	127	8	50	4,341
2014	1,645	834	1,858	130	8	50	4,525
2015	1,630	850	1,759	130	8	51	4,428
2016	1,562	829	1,768	128	8	53	4,347
2017	1,542	821	1,744	126	8	53	4,294
2018	1,701	839	1,725	128	8	52	4,453
2019	1,610	824	1,710	127	9	50	4,331
2020	1,701	751	1,630	149	8	46	4,286
2021	1,629	740	1,736	149	7	50	4,312
2022	1,640	768	1,511	150	7	47	4,122
2023	1,615	704	1,460	189	8	47	4,024
2024	1,632	709	1,444	195	8	51	4,040
2025	1,628	700	1,443	198	8	54	4,033
2026	1,626	691	1,524	205	8	54	4,108
2027	1,625	684	1,527	193	8	54	4,091
2028	1,626	682	1,629	206	8	55	4,206
2029	1,629	682	1,340	201	8	54	3,915
2030	1,633	687	1,364	205	8	54	3,951
2031	1,639	693	1,290	205	8	53	3,889
2032	1,646	701	1,456	204	8	54	4,069
2033	1,654	711	1,282	205	11	53	3,915
2034	1,663	722	1,374	193	8	53	4,014
2035	1,672	738	1,562	204	8	53	4,238
2036	1,683	757	1,538	203	8	54	4,243
2037	1,694	777	1,456	204	8	54	4,192
2038	1,705	799	1,486	203	8	54	4,256
2039	1,716	822	1,544	203	8	55	4,348

Note: Historic (2012 - 2023); Projected (2024 - 2039)
Appendix 2B-3 has been provided with the 2024 Company Load Forecast instead of the 2024 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
2012	2,187,670	234,947	514	29,114	3,246	4	2,455,496
2013	2,206,657	236,596	526	28,847	3,508	3	2,476,138
2014	2,229,639	237,757	631	28,818	3,653	3	2,500,500
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	2,468,022	252,745	608	29,687	5,286	3	2,756,350
2025	2,499,287	255,100	602	29,757	5,430	3	2,790,179
2026	2,531,721	257,525	596	29,828	5,574	3	2,825,247
2027	2,564,595	259,976	590	29,893	5,718	3	2,860,774
2028	2,597,827	262,447	584	29,954	5,862	3	2,896,675
2029	2,631,236	264,928	578	30,009	6,006	3	2,932,761
2030	2,664,561	267,406	572	30,060	6,150	3	2,968,751
2031	2,697,472	269,860	566	30,106	6,294	3	3,004,300
2032	2,729,661	272,273	560	30,145	6,438	3	3,039,079
2033	2,760,879	274,630	554	30,177	6,582	3	3,072,825
2034	2,790,937	276,922	548	30,202	6,726	3	3,105,337
2035	2,819,694	279,139	542	30,221	6,870	3	3,136,468
2036	2,847,084	281,277	536	30,233	7,014	3	3,166,147
2037	2,873,169	283,340	530	30,240	7,158	3	3,194,439
2038	2,898,044	285,334	524	30,241	7,302	3	3,221,447
2039	2,921,784	287,262	518	30,238	7,446	3	3,247,250

Note: Historic (2012 - 2023); Projected (2024 - 2039)
Appendix 2B-4 has been provided with the 2024 Company Load Forecast instead of the 2024 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
2012	2,086,647	219,447	464	27,265	2,856	2	2,336,680
2013	2,105,500	221,039	477	26,996	3,118	2	2,357,131
2014	2,128,313	222,143	579	26,966	3,267	2	2,381,269
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	2,359,086	236,379	551	27,137	4,912	2	2,628,066
2025	2,389,408	238,656	545	27,187	5,057	2	2,660,854
2026	2,420,898	241,003	539	27,237	5,201	2	2,694,878
2027	2,452,826	243,375	533	27,286	5,345	2	2,729,367
2028	2,485,116	245,768	527	27,341	5,489	2	2,764,243
2029	2,517,588	248,171	521	27,397	5,634	2	2,799,312
2030	2,549,977	250,571	515	27,447	5,778	2	2,834,289
2031	2,581,953	252,947	509	27,491	5,922	2	2,868,824
2032	2,613,204	255,282	503	27,527	6,067	2	2,902,584
2033	2,643,477	257,562	497	27,557	6,211	2	2,935,305
2034	2,672,584	259,774	491	27,580	6,355	2	2,966,785
2035	2,700,383	261,912	485	27,597	6,499	2	2,996,877
2036	2,726,808	263,970	479	27,606	6,644	2	3,025,509
2037	2,751,919	265,953	473	27,610	6,788	2	3,052,745
2038	2,775,817	267,866	467	27,609	6,932	2	3,078,693
2039	2,798,577	269,714	461	27,604	7,076	2	3,103,434

Note: Historic (2012 - 2023); Projected (2024 - 2039)
Appendix 2B-5 has been provided with the 2024 Company Load Forecast instead of the 2024 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
2012	101,024	15,501	50	1,849	390	2	118,816
2013	101,158	15,557	50	1,851	390	1	119,007
2014	101,326	15,614	52	1,853	386	1	119,231
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	108,936	16,366	57	2,550	374	1	128,284
2025	109,879	16,444	57	2,570	373	1	129,324
2026	110,823	16,523	57	2,591	373	1	130,368
2027	111,769	16,601	57	2,607	373	1	131,407
2028	112,710	16,679	57	2,612	373	1	132,433
2029	113,649	16,757	57	2,612	372	1	133,448
2030	114,584	16,835	57	2,613	372	1	134,462
2031	115,520	16,913	57	2,615	372	1	135,477
2032	116,457	16,991	57	2,617	371	1	136,495
2033	117,401	17,069	57	2,620	371	1	137,519
2034	118,353	17,148	57	2,622	371	1	138,552
2035	119,311	17,227	57	2,625	371	1	139,591
2036	120,276	17,307	57	2,627	370	1	140,638
2037	121,249	17,387	57	2,629	370	1	141,694
2038	122,227	17,467	57	2,632	370	1	142,754
2039	123,207	17,548	57	2,634	370	1	143,816

Note: Historic (2012 - 2023); Projected (2024 - 2039)
Appendix 2B-6 has been provided with the 2024 Company Load Forecast instead of the 2024 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

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

Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)
2012	16,787	14,544
2013	16,366	15,106
2014	16,249	16,840
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	18,113	17,749
2026	18,720	18,088
2027	18,968	18,234
2028	19,332	18,503
2029	19,747	19,127
2030	20,276	19,564
2031	20,770	19,851
2032	21,270	20,212
2033	21,872	20,631
2034	22,538	21,371
2035	23,212	22,057
2036	24,017	22,681
2037	24,706	23,316
2038	28,483	24,971
2039	26,415	25,497

Note: Historic (2012 - 2023); Projected (2024 - 2039)
Appendix 2B-7 has been provided with the 2024 Company Load Forecast instead of the 2024 PJM Load Forecast 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)															
	2021	**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)	16,792	17,317	17,979	18,046	18,283	19,014	19,412	19,873	20,355	20,848	21,377	22,001	22,655	23,427	24,302	25,239	26,151	27,090	28,140
2. Energy Efficiency & Demand Response[2][3]	(331)	(186)	(204)	(92)	(186)	(266)	(346)	(402)	(437)	(461)	(496)	(526)	(551)	(581)	(627)	(654)	(701)	(781)	(916)
3. Customer Choice (non data center)[5]	-	-	-	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)
4. Summer Adjusted Load	16,462	17,131	17,775	17,353	17,497	18,147	18,465	18,870	19,318	19,787	20,280	20,875	21,504	22,245	23,074	23,985	24,849	25,708	26,623
5. % Increase in Adjusted Load (from previous year)	(0.01)	0.04	0.04	0.01	0.01	0.04	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04
B. Winter																			
1. Base Forecast (LSE Equivalent)	14,799	17,999	15,848	17,851	17,928	18,304	18,646	18,954	19,372	19,881	20,436	21,046	21,570	22,158	22,914	23,754	24,567	25,386	26,079
2. Energy Efficiency & Demand Response[2][3]	(331)	(186)	(204)	(92)	(186)	(266)	(346)	(402)	(437)	(461)	(496)	(526)	(551)	(581)	(627)	(654)	(701)	(781)	(916)
3. Customer Choice (non data center)[5]	-	-	-	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)	(601)
4. Winter Adjusted Load	14,469	17,813	15,643	17,158	17,142	17,437	17,699	17,951	18,334	18,819	19,339	19,920	20,418	20,976	21,687	22,500	23,265	24,004	24,562
5. % Increase in Adjusted Load (from previous year)	(0.03)	0.23	(0.12)	0.15	0.01	0.02	0.02	0.02	0.01	0.02	0.02	0.03	0.02	0.02	0.03	0.03	0.03	0.03	0.02
2. Energy (GWh)																			
A. Base Forecast (LSE Equivalent)	88,043	92,316	92,712	102,243	103,848	109,672	113,006	117,186	120,804	124,843	128,978	134,381	139,000	144,755	151,113	158,302	164,952	172,447	180,203
B. Winter Additional Forecast Future BTM[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Energy Efficiency & Demand Response[2][3]	(1,657)	(1,136)	(1,057)	(199)	(621)	(1,039)	(1,394)	(1,659)	(1,826)	(1,944)	(2,110)	(2,268)	(2,397)	(2,518)	(2,717)	(2,845)	(2,983)	(3,101)	(3,285)
D. Customer Choice (non data center)[5]	-	-	-	(3,748)	(3,920)	(3,920)	(3,920)	(3,931)	(3,920)	(3,920)	(3,920)	(3,931)	(3,920)	(3,920)	(3,920)	(3,931)	(3,920)	(3,920)	(3,920)
E. Adjusted Energy	86,386	91,180	91,655	98,296	99,307	104,713	107,693	111,596	115,058	118,979	122,949	128,182	132,684	138,317	144,476	151,526	158,049	165,427	172,999
F. % Increase in Adjusted Energy	0.05	0.06	0.01	0.07	0.01	0.05	0.03	0.04	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.05	0.04	0.05	0.05

(1) Actual metered data
(2) Demand response programs are not classified as capacity resources and are included in adjusted load.
(3) 2021-2023 actual historical data based upon measured and verified EM&V results
(4) Future behind-the-meter, which is not included in the base forecast.
(5) Actuals for customer choice are not available.

Appendix 2B-9: Required Reserve Margin (for VCEA with EPA)

Company Name: Virginia Electric and Power Company — Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)															
	2021	**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)	2,675	2,162	(181)	4,447.22	3,511.71	(182.63)	79.21	316.66	5.69	-	-	-	-	-	-	-	-	-	-
b. Percent of Load	15.9%	12.5%	-1.0%	25.6%	20.1%	-1.0%	0.4%	1.7%	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	2.9%	16.6%	-21.8%	-15.0%	-16.1%	-17.2%	-15.3%	-16.7%	-13.3%	-13.7%	-14.8%	-13.3%	-11.3%	-13.1%	-14.7%	-14.5%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	4,642	3,867	527	846	1,236	989	968	941	955	1,086	1,269	1,387	1,485	1,584	1,704	2,061
b. Percent of Load	N/A	N/A	N/A	27.1%	22.6%	3.0%	4.8%	6.9%	5.4%	5.1%	4.9%	4.8%	5.3%	6.0%	6.4%	6.6%	6.8%	7.1%	8.4%
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	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	N/A

(1) To be calculated based on total net capability for summer and winter.
(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)															
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak(1)	16,462	17,131	17,775	17,353	17,497	18,147	18,465	18,870	19,318	19,787	20,280	20,875	21,504	22,245	23,074	23,985	24,849	25,708	26,623
b. Other Commitments(2)	331	186	204	693	786	867	947	1,003	1,038	1,062	1,097	1,126	1,152	1,182	1,227	1,254	1,302	1,382	1,517
c. Total System Summer Peak	16,792	17,317	17,979	18,046	18,283	19,014	19,412	19,873	20,355	20,848	21,377	22,001	22,655	23,427	24,302	25,239	26,151	27,090	28,140
d. Percent Increase in Total Summer Peak	0.6%	3.1%	3.8%	0.4%	1.3%	4.0%	2.1%	2.4%	2.4%	2.4%	2.5%	2.9%	3.0%	3.4%	3.7%	3.9%	3.6%	3.6%	3.9%
2. Winter																			
a. Adjusted Winter Peak(1)	14,469	17,813	15,643	17,158	17,142	17,437	17,699	17,951	18,334	18,819	19,339	19,920	20,418	20,976	21,687	22,500	23,265	24,004	24,562
b. Other Commitments(2)	331	186	204	693	786	867	947	1,003	1,038	1,062	1,097	1,126	1,152	1,182	1,227	1,254	1,302	1,382	1,517
c. Total System Winter Peak	14,799	17,999	15,848	17,851	17,928	18,304	18,646	18,954	19,372	19,881	20,436	21,046	21,570	22,158	22,914	23,754	24,567	25,386	26,079
d. Percent Increase in Total Winter Peak	-1.3%	21.6%	-12.0%	12.6%	0.4%	2.1%	1.9%	1.7%	2.2%	2.6%	2.8%	3.0%	2.5%	2.7%	3.4%	3.7%	3.4%	3.3%	2.7%

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

(2) Includes energy efficiency, demand side management, and customer choice from Appendix 4H.

Appendix 2B-11: Wholesale Power Sales Contracts

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

WHOLESALE POWER SALES CONTRACTS

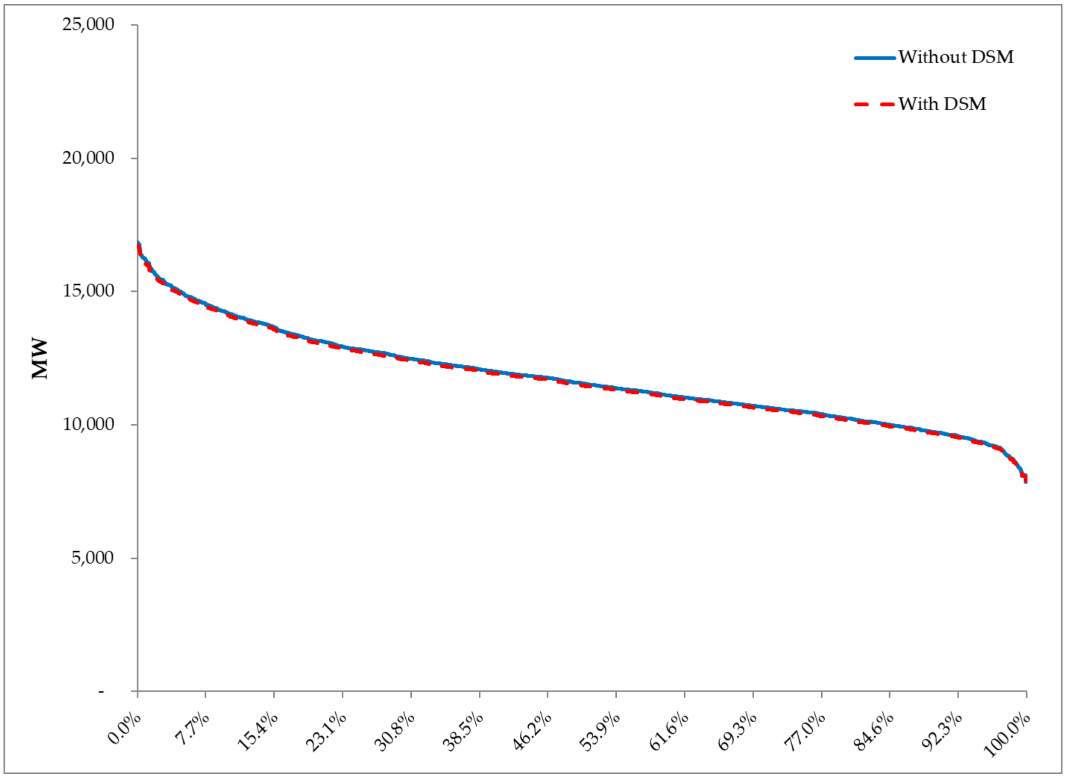
			(Actual)[2]			
Entity	**Contract Length**	**Contract Type**	**2020**	**2021**	**2022**	**2023**
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements[1]	9	10	13	9
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements[1]	10	10	11	10
Virginia Municipal Electric Association	5/31/2031 with annual renewal	Full Requirements[1]	283	291	286	284

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

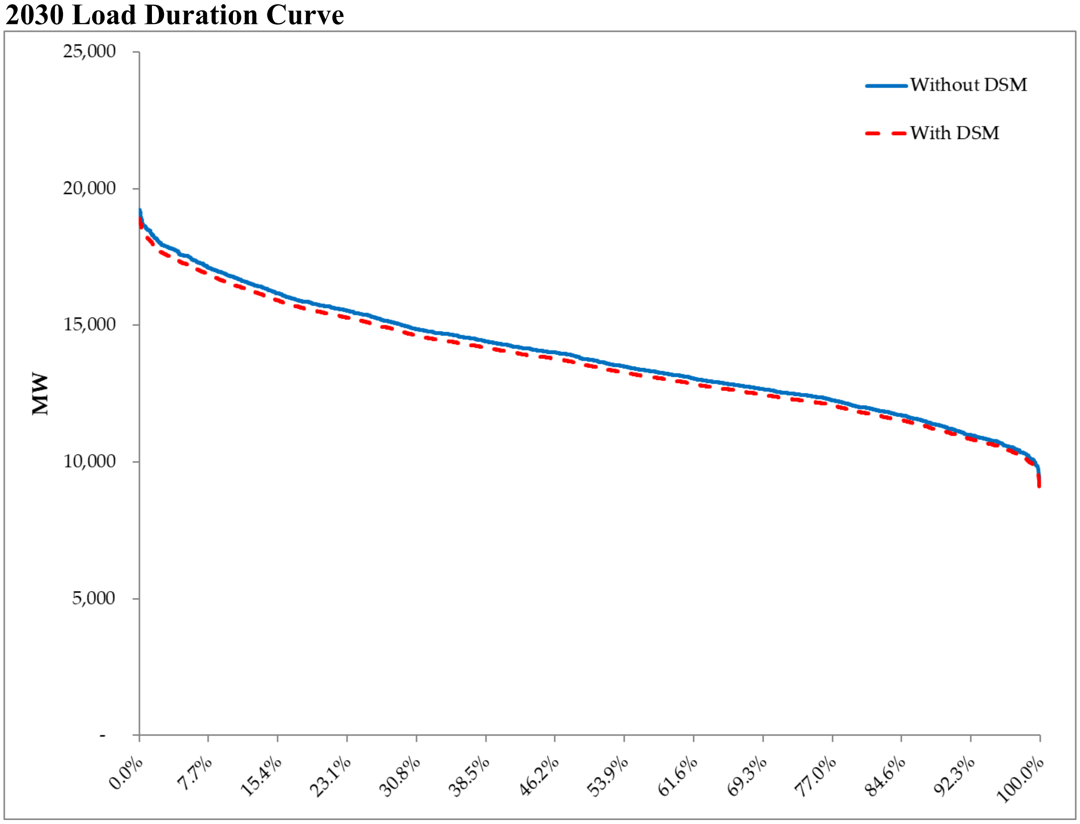
(2) Actual customer peak load measures are included.

Appendix 2B-12: Load Duration Curves

2025 Load Duration Curve

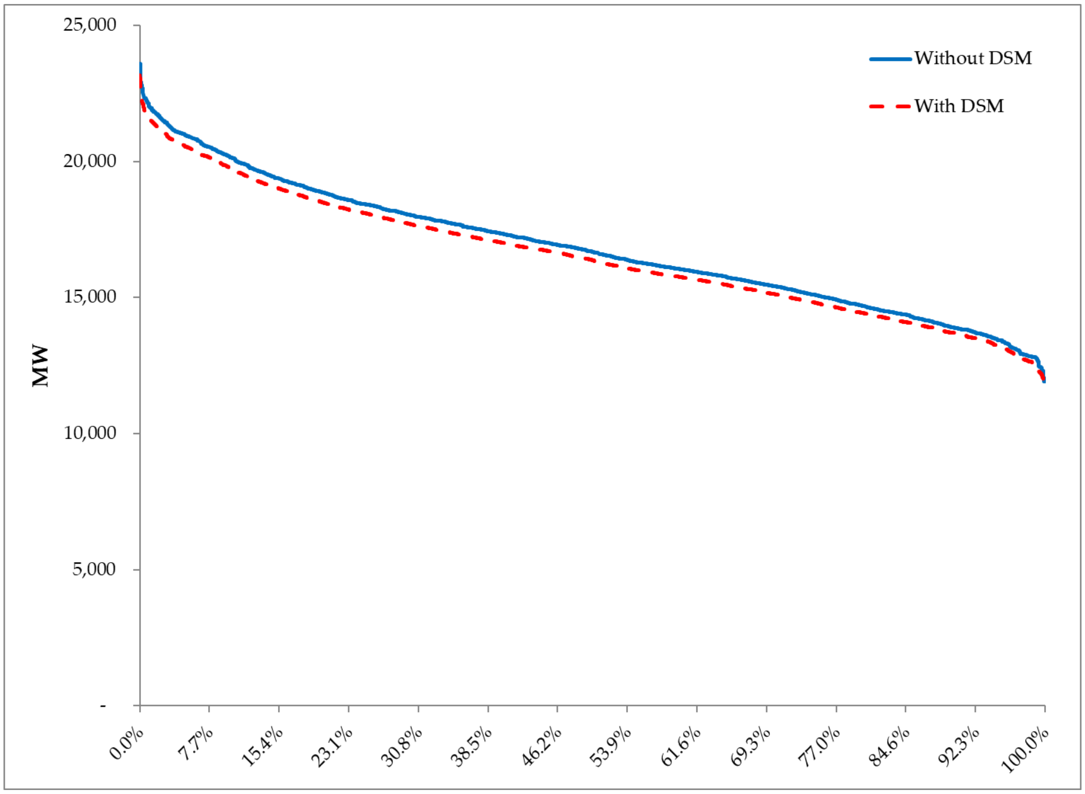


2030 Load Duration Curve



Appendix 2B-12: Load Duration Curves (cont.)

2035 Load Duration Curve



Appendix 2B-13: Economic Assumptions used in the Sales and Hourly Budget Forecast Model
(Annual Growth Rate)

Economic Assumptions Used In the Sales and Hourly Budget Forecst Model (Annual Growth Rate)																	
Year	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**CAGR**
Population: Total, (Thousands)	8,764	8,802	8,836	8,868	8,896	8,923	8,950	8,976	9,002	9,027	9,051	9,073	9,095	9,116	9,137	9,155	0.3%
Disposable Personal Income: (Mil. 17$; SAAR)	473,309	483,313	493,220	504,180	515,628	526,906	538,050	549,095	560,496	572,345	584,301	596,381	608,535	620,808	633,272	645,821	2.1%
Residential Permits: Total, (#, SAAR)	39,116	43,249	46,229	46,432	45,273	43,322	40,934	38,519	36,215	34,036	32,031	30,182	28,449	26,821	25,296	23,887	-3.2%
Employment: Total Manufacturing, (Thousands, SA)	249	250	249	248	247	245	243	241	240	238	236	234	232	230	228	226	-0.6%
Employment: Total Government, (Thousands, SA)	745	747	747	748	750	753	755	757	759	762	764	766	768	770	772	774	0.3%
Gross State Product: Total Manufacturing, (Bil. Ch. 2017 USD, SAAR)	46.4	46.8	47.3	48.5	49.8	51.1	52.2	53.3	54.4	55.5	56.6	57.7	58.7	59.7	60.6	61.6	1.9%
Gross State Product: Total, (Bil. Ch. 2017 USD, SAAR)	605	614	626	639	653	668	682	695	709	723	738	753	768	783	798	813	2.0%
Gross State Product: State and Local Government,(Bil. Chained 2017 $, SAAR)	45.6	46.0	46.3	46.5	46.9	47.2	47.6	47.9	48.4	48.8	49.3	49.8	50.3	50.8	51.2	51.6	0.8%

Source: Moody's Analytics (formerly Economy.com)

SA = Seasonally Adjusted

SAAR = Seasonally Adjusted Annual Rate

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

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Winters Branch - Add 4th TX - DEV (Position #4)	230	Aug-24	VA	0.3
Pearsons 230kV Switch Replacements EOL	230	Aug-24	VA	0.5
Altair 230kV Delivery - NOVEC (Microsoft Leesburg) (Belmont-Altair-Brambleton)	230	Sep-24	VA	51.9
Line #224 (Lanexa -Northern Neck) EOL Rebuild and 2nd Circuit	230	Sep-24	VA	151.0
Youngs Branch - Add 2nd TX - DEV	230	Sep-24	VA	0.8
Aviator 230kV Delivery - DEV	230	Sep-24	VA	42.0
Cemetery Road Sub - 115kV Delivery - DEV	115	Oct-24	VA	5.0
Thunderball (Wildwood) 230kV Delivery - NOVEC	230	Oct-24	VA	13.9
Clifton Forge TX#2 EOL	138/230	Nov-24	VA	3.0
Line #2008 Uprate - Takeoff to Lincoln Park	230	Nov-24	VA	4.5
Line #2008 Uprate - Takeoff to Walney	230	Nov-24	VA	2.0
Gretna 69kV Delivery - Add 2nd TX - DEV	69	Nov-24	VA	0.6
Line #2008 Uprate - Cub Run to Walney	230	Nov-24	VA	2.0
Line #2242 Uprate - Dulles to Lincoln Park	230	Nov-24	VA	6.0
230kV Line Extension Cannon Branch to Winters Branch	230	Dec-24	VA	22.0
Trappe Rock 230kV Delivery - NOVEC	230	Dec-24	VA	16.2
Roundtable 230kV Delivery - Add 3rd and 4th TX	230	Dec-24	VA	0.8
Farmville 230-115kV Transformer #5 EOL Replacement	115/230	Dec-24	VA	6.4
NIVO - Bus Expansion	230	Dec-24	VA	12.0
Magruder Sub - Upgrade 115/34.5kV TX#1 - DEV	115	Dec-24	VA	1.0
Northstar 230kV Delivery - NOVEC	230	Dec-24	VA	10.0
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild - 1.7 mile Double Circuit Sections with Line #2056 (Hornertown-Hathaway)	115	Dec-24	NC	3.4
Metcalf Sub 115kV Delivery - TX #1 Upgrade - DEV	115	Dec-24	VA	0.6
Harrisonburg Transformer#1 Upgrade	115	Dec-24	VA	0.3
NIT Industrial - New 230kV Delivery Point (DEV)	230	Dec-24	VA	5.0
Line #2010 Underground Relocation	230	Dec-24	VA	40.0
Line #100 (Locks to Harrowgate) Partial Rebuild	115	Dec-24	VA	9.1
Bishop Substation -115 kV Delivery (MEC) - Ridge DP	115	Mar-25	VA	15.0
Jeffress Sub - 115 kV Delivery (MEC) - Lakeside DP	115	Feb-25	VA	15.5

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

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Nimbus 230kV Delivery - DEV (Beaumeade-Nimbus-Buttermilk)	230	Apr-25	VA	12.0
Line #141 (Balcony Falls to Skimmer) & Line#28 (Balcony Falls to Cushaw) EOL and Balcony Falls Substation Rebuild	115	May-25	VA	55.0
DTC 230kV Delivery - DEV (Extension of Line #2143 (Beaumeade-BECO) to DTC)	230	Jun-25	VA	60.3
Line #2031 Uprate-Enterprise to Greenway to Roundtable	230	Jun-25	VA	5.9
Line #2186 Uprate - Shellhorn to Enterprise	230	Jun-25	VA	4.0
Line #2218 Uprate-Sojourner to Runway DP to Shellhorn	230	Jun-25	VA	6.5
Rixlew 230 kV Delivery - NOVEC	230	Jun-25	VA	10.0
Lost City - New 230 kV Delivery - DEV	230	Jul-25	VA	10.2
Line #105 (Tarboro-Parmele) EOL Rebuild	115	Jul-25	NC	26.0
Partial Line#5 Retirement (Fork Union to Cunningham DP)-line 1049 retirement	115	Aug-25	VA	5.5
Interconnection 230kV Delivery - DEV (Beaumeade-Interconnection-Nimbus)	230	Sep-25	VA	32.0
Foster Drive 230 kV Delivery - CoM (BCG & AWS)	230	Oct-25	VA	15.3
Ocean Court 230kV Delivery - DEV	230	Oct-25	VA	12.7
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild	115	Nov-25	NC	27.2
Line #2095 Uprate - Cabin Run to Shellhorn	230	Dec-25	VA	8.0
Stratus 230kV Delivery - DEV - (CPR changed to Engineering)	230	Dec-25	VA	24.0
Line #172 & # 197 Conversion - Liberty to Cannon Branch	230	Dec-25	VA	28.0
Pleasant View 230kV Delivery - Add 4th TX - DEV	230	Dec-25	VA	1.0
Hornbaker 230kV Delivery - NOVEC (Avanti) (Liberty-Hornbaker-Pioneer)	230	Apr-26	VA	45.0
Line #574 - Ladysmith to Elmont Rebuild - EOL	500	May-26	VA	91.3
Bear Run Sub - Cub Run 230kV Expansion - NOVEC	230	Sep-26	VA	24.5
Wishing Star DP -NOVEC	230	Dec-26	VA	10.0
Idylwood - Convert Straight Bus to Breaker and a Half	230	Dec-26	VA	159.3
Bristers - 500-230 kV TX Expansion	230/500	May-27	VA	65.0
Line #2008 Uprate - Loudoun to Takeoff	230	Aug-27	VA	4.6
Partial Line #83 EOL Rebuild	115	Mar-28	VA	23.0

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)
Winters Branch - Add 4th TX - DEV (Position #4)	230	Aug-24	VA	0.3
Pearsons 230kV Switch Replacements EOL	230	Aug-24	VA	0.5
Altair 230kV Delivery - NOVEC (Microsoft Leesburg) (Belmont-Altair-Brambleton)	230	Sep-24	VA	51.9
Line #224 (Lanexa -Northern Neck) EOL Rebuild and 2nd Circuit	230	Sep-24	VA	151.0
Youngs Branch - Add 2nd TX - DEV	230	Sep-24	VA	0.8
Aviator 230kV Delivery - DEV	230	Sep-24	VA	42.0
Cemetery Road Sub - 115kV Delivery - DEV	115	Oct-24	VA	5.0
Thunderball (Wildwood) 230kV Delivery - NOVEC	230	Oct-24	VA	13.9
Clifton Forge TX#2 EOL	138/230	Nov-24	VA	3.0
Line #2008 Uprate - Takeoff to Lincoln Park	230	Nov-24	VA	4.5
Line #2008 Uprate - Takeoff to Walney	230	Nov-24	VA	2.0
Gretna 69kV Delivery - Add 2nd TX - DEV	69	Nov-24	VA	0.6
Line #2008 Uprate - Cub Run to Walney	230	Nov-24	VA	2.0
Line #2242 Uprate - Dulles to Lincoln Park	230	Nov-24	VA	6.0
230kV Line Extension Cannon Branch to Winters Branch	230	Dec-24	VA	22.0
Trappe Rock 230kV Delivery - NOVEC	230	Dec-24	VA	16.2
Roundtable 230kV Delivery - Add 3rd and 4th TX	230	Dec-24	VA	0.8
Farmville 230-115kV Transformer #5 EOL Replacement	115/230	Dec-24	VA	6.4
NIVO - Bus Expansion	230	Dec-24	VA	12.0
Magruder Sub - Upgrade 115/34.5kV TX#1 - DEV	115	Dec-24	VA	1.0
Northstar 230kV Delivery - NOVEC	230	Dec-24	VA	10.0
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild - 1.7 mile Double Circuit Sections with Line #2056 (Hornertown-Hathaway)	115	Dec-24	NC	3.4
Metcalf Sub 115kV Delivery - TX #1 Upgrade - DEV	115	Dec-24	VA	0.6
Harrisonburg Transformer#1 Upgrade	115	Dec-24	VA	0.3
NIT Industrial - New 230kV Delivery Point (DEV)	230	Dec-24	VA	5.0
Line #2010 Underground Relocation	230	Dec-24	VA	40.0
Line #100 (Locks to Harrowgate) Partial Rebuild	115	Dec-24	VA	9.1
Bishop Substation -115 kV Delivery (MEC) - Ridge DP	115	Mar-25	VA	15.0
Jeffress Sub - 115 kV Delivery (MEC) - Lakeside DP	115	Feb-25	VA	15.5

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)
230kV Line Extension to Relieve Cloverhill Loop (Winters Branch - Wakeman)	230	Mar-25	VA	3.9
EPG - Add 2nd and 3rd TX - DEV	230	Mar-25	VA	6.1
Nimbus 230kV Delivery - DEV (Beaumeade-Nimbus-Buttermilk)	230	Apr-25	VA	12.0
Line #141 (Balcony Falls to Skimmer) & Line#28 (Balcony Falls to Cushaw) EOL and Balcony Falls Substation Rebuild	115	May-25	VA	55.0
Davis Drive - 230kV Ring Bus Expansion - Line Extension W&OD Trail to Sub	230	Jun-25	VA	15.0
Clifton - Replace Overdutied L282 Breaker	230	Jun-25	VA	0.5
Install 115kV breaker at Stuarts Draft station	115	Jun-25	VA	5.0
Cumulus 230kV Delivery - Add 5th TX - DEV	230	Jun-25	VA	0.5
DTC 230kV Delivery - DEV (Extension of Line #2143 (Beaumeade-BECO) to DTC)	230	Jun-25	VA	60.3
Sherwood Transformer#2 Upgrade	115	Jun-25	VA	0.4
Line #2031 Uprate-Enterprise to Greenway to Roundtable	230	Jun-25	VA	5.9
Line #2186 Uprate - Shellhorn to Enterprise	230	Jun-25	VA	4.0
Line #2188 Uprate-Shellhorn to Greenway to Lockridge	230	Jun-25	VA	3.8
Line #2214 Uprate - Buttermilk to Roundtable	230	Jun-25	VA	4.8
Line #2218 Uprate-Sojourner to Runway DP to Shellhorn	230	Jun-25	VA	6.5
Line #2223 Uprate-Roundtable to Lockridge	230	Jun-25	VA	2.6
Rixlew 230 kV Delivery - NOVEC	230	Jun-25	VA	10.0
Line #249 (Carson to Locks) Rebuild and Energize TX #1	230	Jun-25	VA	25.6
Line #2151 Uprate - Railroad DP to Gainesville	230	Jun-25	VA	6.1
King and Queen 230kV Delivery - DEV	230	Jul-25	VA	1.9
Lost City - New 230 kV Delivery - DEV	230	Jul-25	VA	10.2
Varina SUB - add new TX (TX #2) - DEV	230	Jul-25	VA	0.5
Line #105 (Tarboro-Parmele) EOL Rebuild	115	Jul-25	NC	26.0
Evans Creek Sub - Roanoke DP - 230kV Delivery-DEV_New 230kV Line from Tunstall to Evans Creek and Evans Creek to Raines	230	Aug-25	VA	30.0

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)
Raines Sub - Interstate DP - 230kV Delivery-DEV-New 230kV Line from Tunstall to Raines	230	Aug-25	VA	20.0
Tunstall Sub - Hillcrest DP - 230kV Delivery-DEV-New Unity 500/230kV Sub - Two New 230kV Lines from Unity to Tunstall	230/500	Aug-25	VA	140.0
Partial Line#5 Retirement (Fork Union to Cunningham DP)-line 1049 retirement	115	Aug-25	VA	5.5
Trident 230 kV Delivery - NOVEC (ARC West) (Gainesville-Trident-Wheeler)	230	Sep-25	VA	15.8
Interconnection 230kV Delivery - DEV (Beaumeade-Interconnection-Nimbus)	230	Sep-25	VA	32.0
Park Center 230kV Delivery - DEV	230	Sep-25	VA	10.0
Foster Drive 230 kV Delivery - CoM (BCG & AWS)	230	Oct-25	VA	15.3
Ocean Court 230kV Delivery - DEV	230	Oct-25	VA	12.7
Prentice Drive 230kV Delivery - DEV (CPR changed to Engineering)	230	Oct-25	VA	20.0
Southall (North Louisa (REB)) 230kV Delivery (Amazon AZ) - ODEC - Engineering	230	Nov-25	VA	55.0
Line #77 (Carolina-Roanoke Rapids Hydro) EOL Rebuild	115	Nov-25	VA	7.4
Line #81 (Carolina - S Justice Branch) EOL Partial Rebuild	115	Nov-25	NC	27.2
Install 2nd 115kV 33.67MVar Cap bank at Harrisonburg	115	Dec-25	VA	1.0
Walnut Creek 115kV switching station	115	Dec-25	VA	23.7
Line #2095 Uprate - Cabin Run to Shellhorn	230	Dec-25	VA	8.0
Stratus 230kV Delivery - DEV - (CPR changed to Engineering)	230	Dec-25	VA	24.0
Brickyard 230kV Delivery - DEV	230	Dec-25	VA	6.6
Buttermilk 230kV Delivery - Add 3rd and 4th TX	230	Dec-25	VA	1.0
Butler Farm Sub - 230kV Delivery-DEV- Bailey DP - New Finneywood 500/230kV Sub a new 230kV Line (Butler Farm - Finneywood) a nd a new 230kV Line (Butler Farm - Clover)	230/500	Dec-25	VA	220.0
Line #2019 (Greenwich to Thalia) EOL Partial Rebuild	230	Dec-25	VA	14.3
Line #293 (Staunton to Valley) & Partial Line #83 EOL	230	Dec-25	VA	44.8
Line #202 - Clark to Idylwood Uprate	230	Dec-25	VA	8.0

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 #2104 (Cranes Corner to Stafford) partial uprate	230	Dec-25	VA	28.3
Line #172 & # 197 Conversion - Liberty to Cannon Branch	230	Dec-25	VA	28.0
500kV / 230kV Line Extension - Southern (Wishing Star to Mars)	230/500	Dec-25	VA	842.3
Verona Transformer#2 New Circuit Switcher	115	Dec-25	VA	0.5
Princess Anne Sub upgrade TX1	115	Dec-25	VA	0.5
Line #53 (Chesterfield - Kevlar) Install Reymet Tap	115	Dec-25	VA	3.0
Line #183 Rebuild to Resolve EOL and 2021 OW Violations	115	Dec-25	VA	38.0
Line #53 and Line #72 (Chesterfield to Brown Boveri Tap) EOL Partial Rebuild	115	Dec-25	VA	9.8
Pleasant View 230kV Delivery - Add 4th TX - DEV	230	Dec-25	VA	1.0
230kV Line Extension to Relieve Waxpool Loop (Nimbus to Farmwell)	230	Dec-25	VA	5.7
Line #2007 (Lynnhaven to Thalia) EOL Rebuild	230	Dec-25	VA	28.7
Brambleton Overdutied Breaker Replacement (SC102,H302, H402, 218302)	230	Dec-25	VA	1.7
Line #2011 Uprate - Cannon Branch to Clifton (Rebuild)	230	Dec-25	VA	31.7
Harrisonburg TX#6 EOL	115	Jan-26	VA	5.2
Line #2209 Uprate Evergreen Mills to Yardley	230	Jan-26	VA	5.0
Decoy Airfield - 230kV Delivery - DEV	230	Feb-26	VA	12.0
Broderick Drive 230kV Delivery - DEV	230	Feb-26	VA	24.5
Twin Creeks Sub 230kV Delivery - DEV	230	Mar-26	VA	20.0
Bring 2-230 kV Sources into White Oak SUB and Resolve 300 MW Load Loss Violation - Engineering Assessment	230	Apr-26	VA	42.2
Hornbaker 230kV Delivery - NOVEC (Avanti) (Liberty-Hornbaker-Pioneer)	230	Apr-26	VA	45.0
Northwoods 230kV Delivery - NOVEC	230	Apr-26	VA	15.8
Germanna 230kV Delivery - DEV	230	Apr-26	VA	24.8
Foxbrook Lane 230kV Delivery - REC (AWS Central Louisa - 1st DP)	230	May-26	VA	55.0
Line #574 - Ladysmith to Elmont Rebuild - EOL	500	May-26	VA	91.3
Alexanders Corner Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Deep Creek Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Deep Creek Tx 2 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Brown Boveri Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
Quantico Tx 1 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3

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)
Quantico Tx 2 Replace Ground Switch with Circuit Switcher	115	May-26	VA	0.3
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
Line #502 Terminal Upgrade-Loudoun to Mosby	500	Jun-26	VA	6.3
Daves Store 230kV Delivery - DEV	230	Jun-26	VA	36.5
Tunis Tx 1 Replace Ground Switch with Circuit Switcher	115	Jun-26	NC	0.3
Lines #211 and #228 (Chesterfield to Hopewell) partial rebuild	230	Jun-26	VA	12.3
Line #126 (Earleys to Kelford) Partial Rebuild	115	Jun-26	NC	18.8
Cloud 115kV Cap Bank	115	Jun-26	VA	1.5
Line #23 Bell Ave to Suffolk Partial Rebuild	115	Jun-26	VA	39.5
Line #1024 (Chestnut - S Justice Branch) EOL Rebuild	115	Jun-26	NC	5.1
Spartan - New 230kV Substation	230	Jun-26	VA	21.3
Sycolin Creek 230kV Delivery - DEV	230	Jun-26	VA	28.0
Line #2226 (Clover to Easters) Partial Rebuild (DNH)	230	Jun-26	VA	34.0
Line #205 (Locks to Tyler) Partial Rebuild	230	Jun-26	VA	27.0
Jeffress Substation 230 kV Delivery (MEC) - Lakeside DP	230	Jul-26	VA	92.6
Line #2172 Uprate - Brambleton to Evergreen	230	Jul-26	VA	2.3
Line #2213 Uprate - Yardley to Cabin Run	230	Jul-26	VA	1.8
Line #2210 Uprate - Brambleton to Evergreen Mills	230	Jul-26	VA	2.3
Daves Store 230 kV Line Extension (New) (Cut and Extend Line #2161 Gainesville - Wheeler)	230	Aug-26	VA	45.9
Gemini 230 kV Delivery - DEV	230	Aug-26	VA	15.3
Bear Run Sub - Cub Run 230kV Expansion - NOVEC	230	Sep-26	VA	24.5
Install Cap Bank at Lexington Substation	500	Nov-26	VA	5.9
Mint Springs (Jacksonville) 230kV Delivery - NOVEC	230	Nov-26	VA	16.0
Possum Point 2nd 500-230kV TX (Ox Overloads) (PP 500kV - PP230kV)	230/500	Nov-26	VA	23.1
Wishing Star DP -NOVEC	230	Dec-26	VA	10.0
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	11.4

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)
Occoquan 500-230kV TX (OX violation); Line 2013 Upgrade and Cut in of Line #571 and #237	230/500	Dec-26	VA	84.5
Line #29 Fredericksburg to Aquia Harbor Rebuild	230	Dec-26	VA	59.5
Idylwood - Convert Straight Bus to Breaker and a Half	230	Dec-26	VA	159.3
Line #108 (Boykins-Tunis) EOL Rebuild	115	Dec-26	NC	72.7
Line #584 Terminal Upgrade-Loudoun to Mosby	500	Dec-26	VA	6.4
Line #2056 (Hornertown-Hathaway) EOL Rebuild	230	Dec-26	NC	49.1
City of Franklin P&L DP#4 (Pretlow) - New 115kV Delivery Point	115	Dec-26	VA	2.5
Remington CT 230 kV Terminal Upgrades (Line #2114)	230	Dec-26	VA	2.6
Gainesville 230 kV Terminal Upgrades (Line #2222)	230	Dec-26	VA	9.2
Otterdam Sub - 230kV Delivery (MEC) - Otterdam DP	230	Dec-26	VA	25.0
Bermuda Hundred 230kV Delivery - DEV	230	Dec-26	VA	15.0
Line #260 (Harrisonburg to Grottoes) EOL Rebuild	230	Dec-26	VA	28.0
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
Lunar 230kV Delivery - DEV	230	Mar-27	VA	28.0
Youngs Branch - Add 3rd, 4th, 5th TX - DEV (Position #1,3,5)	230	Apr-27	VA	1.2
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
Pluto 230 kV Delivery - DEV	230	Jun-27	VA	64.5
Terminate Line 583 Doubs - Bismark into Woodside 500kV DOM	500	Jun-27	VA	5.1
Lines #2150 & #2081 Uprates-Golden to Paragon Park	230	Jun-27	VA	3.0
Line #2207 Uprate- Paragon Park to Beco	230	Jun-27	VA	5.3
Line #256 (Ladysmith - St John) Partial Rebuild	230	Jun-27	VA	31.7
Loudoun Capacitor Banks	230/500	Jun-27	VA	90.1
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 #272 (Dooms to Grottoes) EOL Rebuild	230	Jul-27	VA	34.0
Line #2008 Uprate - Loudoun to Takeoff	230	Aug-27	VA	4.6
Line #265 Uprate - Sully to Takeoff	230	Aug-27	VA	4.6

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)
Takeoff 230kV Delivery - DEV Transformers	230	Aug-27	VA	4.0
Takeoff Substation 230kV Interconnection for Poland Loop	230	Aug-27	VA	45.9
230kV Line Extension to Relieve Poland Loop (Aviator to Takeoff)	230	Aug-27	VA	29.5
Spring Hill 230kV Delivery - DEV	230	Aug-27	VA	35.0
Edsall 230 kV Delivery - DEV	230	Oct-27	VA	23.2
Mountain Run new 230kV substation (Named Cirrus) and partial conversion of lines #2 and #70 to 230kV; Convert lines #2 and #70 to 230kV and connect to Line #2199	230	Nov-27	VA	60.0
Line # 2054 (Charlottesville to Hollymead) Rebuild	230	Dec-27	VA	71.1
Locks Substation 230/115 kV Transformer Upgrade	115/230	Dec-27	VA	7.1
Line # 2135 (HollyMeade to Gordonsville) Rebuild	230	Dec-27	VA	36.8
Line #58 (Skiffes to Yorktown) EOL Partial Rebuild	115	Dec-27	VA	6.0
Line #209 and #58 (Skiffes to Yorktown) EOL Partial Rebuild	115/230	Dec-27	VA	13.5
Terminate New Nextera 500kV Line from Woodside into Goose Creek Sub DOM	500	Dec-27	VA	30.5
Line #2101 Uprate - Bristers to Bristers Junction	230	Dec-27	VA	23.0
Sloan Drive - 230kV Delivery - DEV	230	Dec-27	VA	30.0
5-2 North Line Extension - Aspen to Golden	230/500	Dec-27	VA	623.0
Line #204 and #220 Partial Rebuild EOL	230	Dec-27	VA	5.4
Nokesville to Hornbaker 230 kV Line (new)	230	Dec-27	VA	139.0
500 kV line extension - Aspen to Doubs	230/500	Dec-27	VA	74.0
Apollo 230kV Delivery - DEV	230	Mar-28	VA	28.0
Partial Line #83 EOL Rebuild	115	Mar-28	VA	23.0
Atlas 230 kV Delivery - DEV	230	Apr-28	VA	15.4
Line #557 (Chickahominy to Elmont) EOL Rebuild	500	Jun-28	VA	58.2
5-2 Connecter - Mars to Golden	230/500	Jun-28	VA	342.9
Starlight 230kV Delivery - DEV	230	Jun-28	VA	28.0
Lucky Hill Substation - paused	230	Jun-28	VA	7.5
Barrister Sub 230kV Delivery - DEV (CPR changed to Engineering)	230	Jun-28	VA	24.0
Lines #2150 & #2081 Uprates-Golden to Sterling Park	230	Sep-28	VA	8.0
Lines #2194 & #9231 Uprates-Davis Drive to Sterling Park	230	Sep-28	VA	5.5

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)
Nimbus 230kV Delivery - Add 3rd and 4th TX	230	Oct-28	VA	1.1
Lines #233 and 291 (Dooms to Charlottesville) Rebuild	230	Dec-28	VA	112.4
Weyers Cave Substation - New 2nd Transformer	115	Dec-28	VA	0.9
Line #246 Earleys to Suffolk EOL Rebuild	230	Dec-28	VA-NC	150.0
Convert Line #29 Fredericksburg to Possum Point to 230 kV	230	Jan-29	VA	56.7
Line #29 and #252 (Possum Point to Aquia Harbor) Rebuild	230	Jan-29	VA	38.0
Line #10 (Goshen to Craigsville) EOL Partial Rebuild	115	Mar-29	VA	29.6
Fentress Sub - Add 2nd TX	230	May-29	VA	0.4
Vint Hill 500-230 kV Expansion	230/500	Jun-29	VA	115.0
500/230kV Morrisville-Wishing Star Upgrades	230/500	Jun-30	VA	852.9
New Nextera 500 kV Line from Woodside to Goose Creek Sub (DOM Scope)	500	Sep-30	VA	15.6
Replace Overdutied Breakers _ 2022 Reliability Open Window #3	230/500	Oct-31	VA	66.3

Appendix 2D: Transmission System Reliability Analyses

I. Background

Power system reliability is determined by both the transmission network and generation mix. Replacing traditional dispatchable, synchronous generation with renewable inverter-based resources introduces complexities regarding inertial and frequency response, short circuit response, and black-start capability—all components of power system reliability. In 2020, the Company provided an initial overview of the analyses that it would need to perform to investigate the transmission reliability issues resulting from the addition of significant renewable energy resources and the retirement of synchronous generators powered by coal or gas. As explained in the 2024 IRP, the Company has included and will continue to include the most recent reliability analyses in its integrated resource plans and update filings.

To accommodate the time necessary to complete a comprehensive transmission reliability analysis, the work associated with the transmission portion of the 2024 IRP was started in January 2024, using the 2023 PJM load forecast. Each year, PJM releases RTEP cases that are five years ahead of the current year to dictate how the transmission system will be built. For the 2024 IRP, the transmission analysis started with a power flow case provided by PJM through the RTEP process. Specifically, the following studies were performed as part of the 2024 IRP transmission reliability analysis, and are discussed in further detail in the Sections that follow:

- *An Import Limit Study for the DOM Zone*: The study on DOM Zone import and export limits based on transmission system constraints estimates how much power can flow through the transmission system. It does not evaluate whether this power would be available for import.
    - The import limit study for the DOM Zone was completed first because it is an input to the resource adequacy analysis to understand the limitations of import from the transmission line capacity.
    - This analysis was completed at the beginning of March 2024.[1]
- *An Inertial and Frequency Response Study*: The inertial and primary frequency response study evaluates how the integration of more inverter-based resources ("IBRs") will affect the system frequency.
    - The study relied on the resource mix determined from the modeling process and was completed in September 2024.
    - The VCEA without EPA Portfolio and the VCEA with EPA Portfolio were analyzed as part of this study.

[1] As part of the 2023 IRP proceeding, the Company agreed to use updated import/export limits in the 2024 IRP's transmission analysis, as recommended by the Hearing Examiner's Recommendation No. 28. The Company specified that the study will focus on DOM Zone, not DOM LSE.

- *A Short Circuit System Strength Analysis*: A short circuit analysis study evaluates the system's capability to quickly recover after faults caused by physical damage to transmission lines or equipment (*e.g.*, due to storms). It also assesses whether the internal controls of IBRs will still work in weak areas of the system.
    - The study also relied on the resource mix determined from the modeling process and was completed in September 2024.
    - The VCEA without EPA Portfolio and the VCEA with EPA Portfolio were analyzed as part of this study.

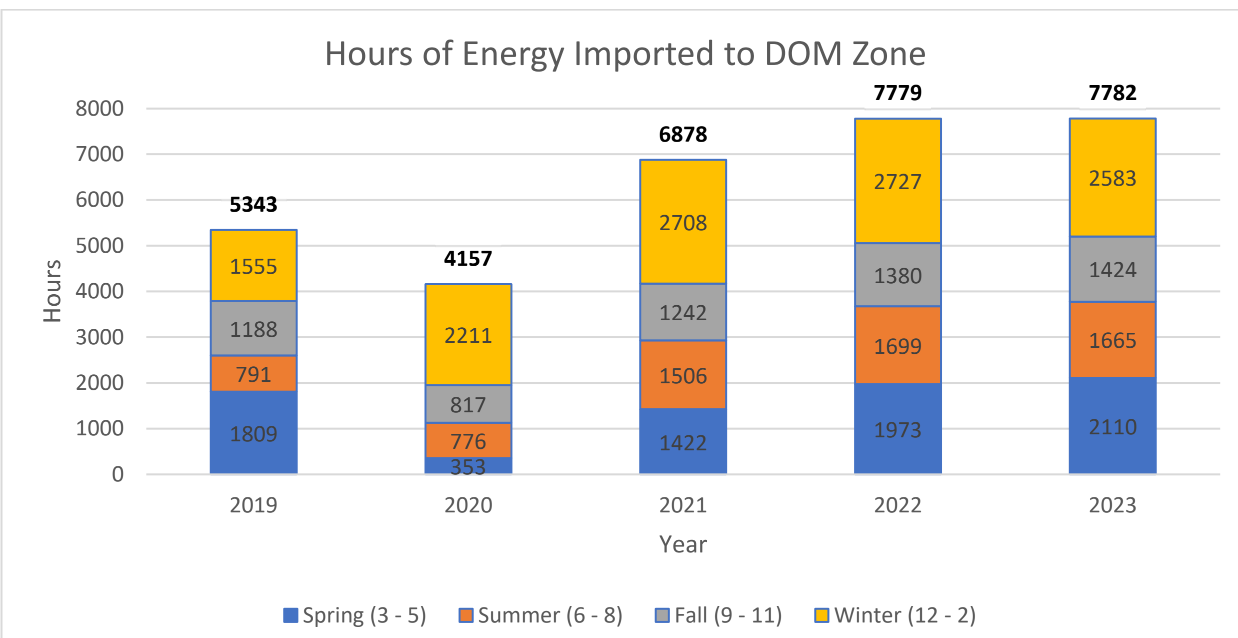
- *Review of System Restoration and Black Start Capabilities*

For reference purposes, a chart of defined terms for purposes of this appendix is included in Section VII.

II. 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 2019 through 2023. For example, in 2023, the Company imported power for 7,782 hours out of 8,760 hours in a year, or 88.8% of the time. This historical data does not represent the amount of import the Company required. Rather, it 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-Export Analysis performed by Quanta Technology re-examined seasonal import and export capability into DOM Zone. Specifically, the study evaluated the capability of the transmission network to carry electricity from regions external to the DOM Zone into the DOM Zone. The methodology used to determine the transmission import limit for the DOM Zone and the study results are outlined below.

A transfer limit analysis on the PJM 2023 Series RTEP 2028 Summer, Winter and Light Load cases was performed. The year 2028 was chosen because of the way the RTEP cases are generated and updated. In 2023, PJM released a case with expected load growth five years out for 2028. After the PJM open window projects were selected to resolve reliability problems, a version of the 2028 case was released that included the new projects to solve the reliability violations. Thus, given October 15, 2024 filing date for the 2024 IRP and the timing of the 2024 PJM Open Window for 2029, it was necessary to use the 2028 case to avoid speculative transmission projects and reliability violations. The PJM 2023 Series RTEP 2028 cases assume the transmission upgrades are in service in 2028. Each case has a specific load and generation profile based on the 2023 load forecast.

The PJM RTEP cases only include generators that have a signed Interconnection Service Agreement ("ISA"). Even though CVOW is under construction, an ISA has not been signed with PJM. Since the CVOW project will be completed before 2028, however, CVOW was included in the transmission import-export analysis for better accuracy.

The import-export analysis proportionally increased generation from outside of the DOM Zone and decreased generation inside of the DOM Zone to increase transfer of power into the DOM Zone. As transfer levels increased, a contingency—or an outage—was applied to one piece of equipment to simulate equipment failure. The process was then repeated for each piece of equipment in the case. Known as an N-1 contingency analysis, this methodology is consistent with the analyses routinely performed by PJM as outlined in Manual 14B based on NERC TPL-001. In other words, to perform this analysis in a way that was methodologically consistent with analyses routinely performed by PJM, the Company assumed that at least one transmission line or a piece of transmission equipment such as a substation becomes unavailable. After the contingencies were applied, the case was checked for violations to determine whether any lines would be overloaded based on their ratings. The limit chosen represents the maximum transfer across the transmission network without causing equipment violations using the cases listed above.

This analysis found that the DOM Zone's import capability in 2028 ranges between 11,414 MW in winter peak, 11,788 MW in summer peak, and 13,136 MW in shoulder months. These import capability limits are significantly higher than the DOM Zone's historical import levels which reached 7,000 MW. 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. Due to uncertainty surrounding supply chain and permitting risks, the full import capability found through the 2028 cases was not implemented in the alternative Portfolios until 2033.

It is important to note that although the transmission network will support increased power import to the DOM Zone due to transmission network upgrades, there is also risk in assuming that there is available generation to import. In extreme weather conditions or during the outage season in the spring or fall, generation may not be available from neighbors to support DOM Zone or DOM LSE load. This could be compounded by the increasing load and generation retirements in areas adjacent to the DOM Zone. This study merely demonstrates that if power is available in the future, the transmission lines can carry it without violating their limits.

The study performed by Quanta Technology considers the entire DOM Zone because the transmission network overloads depend on how the transmission system is connected, also called system topology, and generation dispatch in the cases studied. It does not make sense from a transmission perspective to remove specific loads to study the DOM LSE. 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.

III. 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. When energy supply and demand are not equal, the frequency of the electrical signal generated from a synchronously rotating machine will deviate from the designed 60 Hertz ("Hz"). The resistance to change in frequency when the energy demand (load) or energy supply (generation) suddenly changes is characterized by the system's inertia. Inertia 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 plants, provide inertia, because they store kinetic energy in the turbine-generator rotors. A typical fossil-fueled power plant stores from two to seven seconds of kinetic energy at full power output. 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"). This allows the power system to maintain balance until reserve generators are brought online or until load is shed to achieve a longer-term balance.

For traditional synchronously rotating generation, the above process is governed by physics. When a generator trips offline for any reason, the remaining units physically slow down the speed at which they are rotating. As more power is required of them, they begin to slowly increase their speed again until they reach 60 Hz. This phenomenon is complicated but has been studied over the last 100 years as the power system has grown and developed.

To further highlight the importance of the system frequency, the FERC, NERC, and Regional Entity Staff Report for 2023 Winter Storm Elliot discusses how during the Winter Storm Uri event in 2021, ERCOT was within four minutes of a complete blackout if the frequency had not recovered. Ramping, regulation, and reserves can be seen as a generator's ability to follow load, and all three are structured by NERC BAL (Resource and Demand Balancing) standards. The responsibility associated with the NERC BAL standards is assigned to PJM as the Balancing Authority and Reliability Coordinator.

For inverter-based resources ("IBRs"), this process is very different. IBRs interface with the alternating current ("AC") power system through an inverter that takes the direct current ("DC") output of solar panels, batteries, or wind turbines and converts it to AC current. This conversion process is not dictated by physics in the same way. Inverters functionality can be changed very substantially by software updates. Although this allows for more flexibility in some situations, it also introduces a completely different strategy for system controls to ensure reliable operations.

To examine synchronous inertial and frequency response, the Company evaluated the expected generation technology mix shown in versions of the VCEA without EPA Portfolio and the VCEA with EPA Portfolio in terms of installed capacity together with the installed reserves. The inertial and frequency response transmission reliability analyses were performed using 2023 Summer Series model for 2028 developed by the Multiregional Modeling Working Group ("MMWG") within the Eastern Interconnection Reliability Group ("ERAG"). The Company used the MMWG model because the dynamic files validated in the MMWG model are the most recent.

The 2023 Summer Series 2028 MMWG case used to study the inertial and frequency response has a set dispatch for each generator in the case. It is a single snapshot in time used for dynamic analysis. As the analysis progresses through the years of the study, variations of the expected generation profile do include changes in generation profiles, but it is still not a comprehensive hourly analysis.

Due to computational requirements of running these types of studies, the Company performed the inertial and primary frequency response study using a simplified system model. This simplified model was validated against the full study and found to be an accurate benchmark. Specifically, a simplified model of the Company's system is represented as a single bus area connected to the PJM system through an equivalent intertie.

The inertial and frequency response analysis was conducted at the two bookends of expected response:

1. The Company is connected to the Eastern Interconnection ("EI"). Being connected to the EI allows the Company to import power. It also allows the system to use the inertia of the entire EI and its generation. This is the best case for studying inertial and frequency response.
2. The Company is completely islanded and has zero import capability or support from the EI. This is the worst-case scenario for studying inertial and frequency response.

The main contingency event studied across the VCEA without EPA Portfolio and the VCEA with EPA Portfolio for each year between 2028 and 2039 was the trip and lockout of all units at the Greensville Power Plant because it is the largest single contingency at around 1,600 MWs in the MMWG model.

For the VCEA without EPA Portfolio and the VCEA with EPA Portfolio, where the Company is connected to the EI, the frequency response measured by the expected RoCoF is around 0.1551 hertz per second ("Hz/s") when connected with the Eastern Interconnect in 2028. Because the VCEA without EPA Portfolio and the VCEA with EPA Portfolio added synchronous generation to meet capacity needs, the RoCoF decreased to 0.139 Hz/s by 2039. The amount of synchronous generation is closely linked to the expected RoCoF. Keep in mind, the lower the RoCoF value, the better.

To study the system when it is islanded from the EI requires several different assumptions. The DOM Zone requires imports across all years of study, meaning there are not enough MWs available to meet the load if the system is islanded. Thus, to study the system response when islanded, the load must be reduced to 17,800 MW. This reduction is because there is not enough generation to meet load across from 2028 to 2039. In this case, the rate of change of frequency rises to 0.4279 Hz/s in 2028. Again, because each Portfolio adds synchronous generation, the RoCoF decreases to 0.324 Hz/s in 2039. While NERC does not specify a strict 1 Hz/s threshold in its standards, it references the importance of maintaining RoCoF within certain limits to prevent system instability and protect grid infrastructure, aligning with the 1 Hz/s benchmark used by other grid operators globally.

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 which 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. The Company is engaged with the NREL UNIFI Consortium that is working on how to integrate grid-forming inverter design. The first installation of a grid-forming inverter in the Dominion Energy system will be installed in a distribution project for the Locks Microgrid project associated with the Grid Transformation and Security Act.

IV. Short-Circuit System Strength Analysis

A short circuit, also known as a fault, is a system disturbance caused by an event such as a tree branch falling across electrical lines, 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.

Currently, protection and control systems—composed of sensors, relays, circuit breakers, reclosers, and fuses installed across the entire system—remove equipment within milliseconds to seconds after a fault occurs. In today's electric grid, a short circuit typically results in a spike in electrical current at the fault location and depressed voltage around the fault location. Protection and control systems in operation today remove short-circuit events by detecting very high currents along with voltage depressions. More sophisticated protection systems are sometimes employed that can use the rate of change of voltages and currents to distinguish heavy system loading from faults. Also, protection and control systems rely heavily on predictable behavior in response to faults. This allows protection and control systems to respond accurately to faults and isolate the least amount of equipment to remove the fault from the grid to provide minimum customer impact. Detection and quick recovery from disturbances occur today because traditional rotating synchronous generators supply a significant amount of current and have a predictable response during short-circuit events, and in ways that are not reliant upon the specific manufacturer of the generator since they are based on the inherent physics of traditional rotating synchronous generators.

In a grid with a high density mix of transmission lines and synchronous generation, the grid is considered strong, and voltage recovers quickly from faults and disturbances. However, as the synchronous portion of the generation mix decreases, the system is less able to return to an equilibrium after a disturbance and protection and control systems have more difficulty simply identifying the presence of a fault.

Inverter-based resources, such as solar and wind, do not provide the same predictable response to fault conditions as traditional synchronous generation. This manifests as no significant current increase during short-circuit events and a fault current output which does not provide the correct signature to determine where on the line a fault occurred. As traditional rotating synchronous generators are retired and replaced with inverter-based generation, the system will experience a fundamental change in short-circuit behaviors across all grid levels, specifically lowering the short circuit strength of the system and removing the predictable grid behavior in response to faults. This will cause the Company's existing protection and control systems, which have been installed across the entire system over decades, to have major challenges in both detecting these short-circuit events and isolating the equipment to protect the public, personnel, and the system. Numerous NERC reports show this problem is not isolated to the Company's grid; it is a challenge that faces any grid with high levels of inverter-based generation. FERC 901 has not yet resulted in changes to the NERC regulations that bind transmission and generation, so the resulting ramifications are not clear at this time.

The Company used the 2017 NERC Reliability Guideline on IBRs integration to guide the short circuit strength analysis. The report defines the Short Circuit Ratio ("SCR") as the ratio between short circuit apparent power ("SCMVA") from a three-phase fault at the Point of Interconnection ("POI") of an IBR facility to the rating of the inverter-based resource connected to that location. Per the recommendation of Quanta Technology, which performed the short circuit study on behalf of the Company, and the NERC report highlighting the need for a different metric in weakly connected systems, the short circuit study was performed using the Short Circuit Ratio with Interaction Factors ("SCRIF").

The SCRIF calculates the SCR at the point of interconnection for each IBR and considers nearby IBRs that are electrically close and could interact with the facility under study. This makes the SCRIF a good metric for studying IBRs in areas with a high penetration. In areas where there is a lower penetration of IBRs, the study still provides accurate results. The SCRIF at each point of interconnection was compared to an acceptable threshold. Based on studies performed by Quanta Technology, a threshold value of SCRIF > 3.5 was set. Quanta Technology recommended this value based on studies they performed to evaluate that the internal inverter control would stay stable when connected to a system with a SCRIF under 3.5.

There is no NERC Standard associated with SCRIF or other types of Short Circuit Ratio calculations; recommendations are based on the needs of the systems being studied.

The short-circuit strength study started with modeling the future resource portfolio within the transmission grid using PJM's 2023 Series RTEP 2028 model, with a focus on the ability of the

Company's system to integrate the IBRs. Starting from RTEP 2028 model, the 2039 case is built according to the VCEA without EPA Portfolio and the VCEA with EPA Portfolio and the PJM load forecast. The SCRIF calculation was performed with the following assumptions:

- Point of interconnection at each inverter-based resource is set to the nearest transmission bus (69 to 500 kV) in order to focus only on bulk system issues and not internal plant issues.
- Only inverter-based resources with grid-following inverters are considered.
- Battery storage systems are assumed to have grid-forming inverters and thus are excluded from the analysis.
- As generation is added over time, it is allocated to locations based on historical integration of solar and wind projects. The results of this analysis could change based on location of resource integration, but that information is not available further in the future.

The results of the study are as follows with no compensation from synchronous condensers:

- For VCEA without EPA Portfolio and VCEA with EPA Portfolio, 14,680 MW of solar and wind IBRs are added. If no synchronous condensers are added, 56% of the generation has a SCRIF over 3.5.

The following bullets provide information on how the system responds when 15 synchronous condensers were added to both VCEA without EPA Portfolio and VCEA with EPA Portfolio:

- 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, 80% of IBRs will have a SCRIF over 3.5.

As the generation mix changes, the Company will continuously reevaluate the system short-circuit strength and address it as necessary.

V. System Restoration and Black Start Capabilities

Large-scale blackouts can harm the public, the economy, and the power system. Black start restores electric power stations and the electric grid without relying on external connections, and it is the most critical scenario for system restoration. A proper black start system restoration plan can help to restore power quickly and effectively.

A black start unit is a generator that can start from its own power without support from the power grid, which is essential in the event of a system-wide blackout. Most generators on the system do not have this capability, as it requires special equipment on-site. Black start units, and the generation included in the system restoration plan, must be dispatchable with constant and predictable output when operational. These requirements are difficult to meet for solar- and wind-generation resources, which are intermittent. Because the system is very fragile during restoration, any changes in the load and generation balance can create instability. The use of intermittent resources, as a result, must be carefully managed if utilized in a black start scenario. 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. As more intermittent resources are connected to the transmission and distribution grid come online and more dispatchable generation is retired, however, the Company must reevaluate system restoration procedures. This will include an investigation into new technology such as grid-forming inverters.

VI. Future Technology Considerations

As the grid continues to evolve and develop with renewable energy resources, so must the technology used to monitor, control, and transport energy. Such technologies can include power quality, reactive resources and voltage control, grid monitoring and control capabilities, energy storage requirements, and high-voltage direct current transmission. Future enhancements in power quality will have to be considered because as variable inverter-based generation increases so do the voltage and frequency fluctuations and the harmonics, which can cause a variety of issues on the grid. For reactive resources and voltage control, the Company will have to continue to look at Flexible AC Transmission Systems ("FACTS") devices, synchronous condensers, and other technologies that support the electromagnetic field required to control voltage levels.

The addition of DERs and the growth and development of EVs and other electrification activities will require future development and enhancements of grid monitoring and control capabilities. The intermittence of wind and solar will render energy storage vital. In that regard, the Company is already making strides in using energy storage to enhance system reliability with the Battery Storage Pilot Program, as discussed in Appendix 3L. At this time, BESS have negligible impact on the transmission grid. But as development continues, the impact must be considered in reliability studies. Finally, as high-voltage direct current ("HVDC") technology evolves and generation continues to move away from load centers, the Company will have to evaluate the possibility of using HVDC to transmit power over long distances with reduced losses. It may also play a role in future offshore wind connections depending on the distance from shore.

Additionally, the Company is investigating Grid Enhancing Technologies ("GETs") to support the existing transmission network. GETS are a wide classification that can almost encompass any advancement deployed on the grid. The current application of the term means a group of technologies that offer a variety of benefits that provide operational flexibility and potentially improve grid performance which can come in the form of both software or hardware solutions. There is currently a pilot project with the Dynamic Line Ratings ("DLR") on particularly congested transmission corridors to understand how to utilize the physical technology attached to the transmission facilities to alleviate operational constraints.

The Company was an early adopter of the FACTs devices, which help dynamically support the system voltage across many operating conditions. The support of the system voltage reduces losses and helps ensure that the system voltage recovers to fault events described in Section IV of this appendix. While these devices are helpful, they use inverter technology which limits the amount of current it can supply to a fault. While the concerns outlined in Section IV are valid, FACTs devices provide system support.

VII. Defined Terms

Inverter Based Resource
Inverter-Based Resources ("IBRs") describe sources of electrical power that are connected to the alternating current ("AC") power grid through an inverter. The power can be generated from a direct current ("DC") source like a solar farm or an AC source at a different frequency – like a wind farm.

Traditional, Dispatchable, Synchronous Generation
Traditional dispatchable synchronous generation refers to power generation systems that include a synchronously spinning mass that is electrically coupled to the power system at 60 Hz, or the frequency of the North American power grid. The output can be controlled to meet electricity demand and maintain grid stability. These systems use synchronous generators, which produce AC by rotating a magnetic field. Commonly, these types of generators are used with nuclear, gas, coal, and hydro power plants. They can be dispatched by the Company's Balancing Authority ("BA"), PJM, to meet demand.

Synchronous generators offer inertial response, stabilizing the grid by resisting frequency changes through their large rotating mass. They also provide frequency response by adjusting output in response to grid frequency changes, helping balance supply and demand. Additionally, synchronous generators can be equipped to have black start capability, enabling them to restart without external power, crucial for recovering from blackouts. They also supply short circuit response, supporting the grid during faults by providing high currents so that system protection elements can sense faults and isolate equipment as designed.

Inter-tie
An inter-tie refers to a connection between two or more power grids, allowing the transfer of electricity across different regions or systems. These inter-ties play a crucial role in enhancing grid reliability, enabling the sharing of resources, and providing mutual support during peak demand or emergencies. By facilitating the flow of electricity between interconnected networks, inter-ties help maintain overall system stability and optimize the efficiency of power distribution.

Island
An electrical island refers to a section of the power grid that operates independently from the main transmission network. When in island mode, the local generators within the island must balance supply and demand internally, maintaining stable voltage and frequency without external support.

HVDC

High Voltage Direct Current ("HVDC") is a method of transmitting electricity over long distances using DC instead of the more common AC. HVDC systems are particularly efficient for long-distance power transmission because they reduce energy losses that occur with AC transmission. This technology also offers enhanced grid stability and control that can stabilize the grid by quickly responding to changes in demand and supply.

Inertial Response
Inertial response refers to the ability of generators to stabilize the electrical grid by resisting changes in frequency. This is achieved through the large rotating mass of the generator, which creates a natural inertia. When there is a sudden imbalance between supply and demand on the grid, the inertia of these rotating masses helps to slow down the rate of frequency change, providing a crucial buffer time for other control mechanisms to respond and restore balance.

Frequency Response
Frequency response refers to the ability of a power system to maintain and restore balance between electricity supply and demand by adjusting the power output of generators in response to changes in grid frequency. When there is an imbalance, such as a sudden increase in demand or a drop in energy supply, the grid frequency can deviate from its nominal value.

Rate of Change of Frequency
Rate of change of frequency ("RoCoF") refers to the rate at which the grid frequency changes over time, typically measured in Hertz per second ("Hz/s"). It is a critical parameter for maintaining grid stability, as rapid changes in frequency can indicate significant imbalances between electricity supply and demand.

Short Circuit with Interaction Factor
Thus, the Short Circuit Ratio with Interaction Factors (SCRIF) method is proposed to more accurately account for the impedances between the considered plants. SCRIF measures the change in voltage at one bus resulting from a voltage change at another bus. Inverter-based resource buses that are electrically close will have a higher Interaction Factor (IF) compared to those that are electrically distant. When multiple inverter-based resources are located very close to each other, they share the grid strength and short circuit level, making the actual grid strength lower than the overall short circuit level calculated at that bus or buses. SCRIF uses inverter-based resource interaction factors to capture voltage sensitivity between resources, serving as a screening tool for potential control issues. One advantage of SCRIF is its adaptability to any configuration for connecting multiple inverter-based resources.

Black Start Capability
Black start capability refers to the ability of a power station to restart its operations without relying on the transmission network. This feature is crucial during a blackout or significant power outage, as it allows the power station to generate electricity independently and gradually restore the grid. Typically, black start capability involves using a smaller, onsite generator to power up the main generators.

Dynamic Line Ratings
Dynamic line ratings ("DLR") refer to the real-time assessment of the capacity of electrical transmission lines. Unlike static ratings, which are based on conservative estimates under worst-case conditions, DLR uses actual environmental and operational data, such as temperature, wind speed, and line tension, to determine the maximum current a line can safely carry at any given moment. This approach can significantly enhance the efficiency and reliability of power transmission by allowing operators to optimize the utilization of existing infrastructure.

Grid Enhancing Technologies
Grid-enhancing technologies ("GETs") are a wide classification that can almost encompass any advancement deployed on the grid. The current application of the term means a group of technologies that offer a variety of benefits that provide operational flexibility and potentially improve grid performance which can come in the form of both software or hardware solutions. Examples of GETs in use across the Dominion Energy Virginia footprint include Advanced Conductors, Flexible AC Transmission Systems ("FACTS"), Fixed Series Capacitor Banks ("FSCs"), and Dynamic Line Ratings ("DLR").

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 5.2.2 in the 2024 IRP.

In addition to interconnections costs, the 2024 IRP 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 analysis when a total of 20 GW and 30 GW of solar generation is present on the transmission grid. The analysis was performed based off of PJM Interconnection LLC's ("PJM") generation interconnection queue to best reflect the interconnection locations, sizes, and behaviors of the solar developers. The resulting power flow violations results were then used to calculate the cost per kilowatt ("kW") of enhancements to the Company's transmission system.

All Portfolios include the addition of significantly more solar generation. Figure 1 shows the incremental integration costs assumed for Company-build solar as additional solar generation is added to the system.

Figure 1 – Total Solar Integration Costs

Solar MW	Total Cost
Up to 20,000	$108.68 per kW
20,000- 30,000	$105.66 per kW

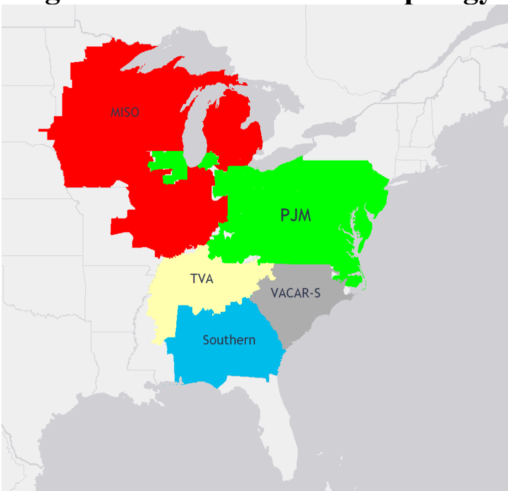
III. Generation Re-dispatch Costs

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.

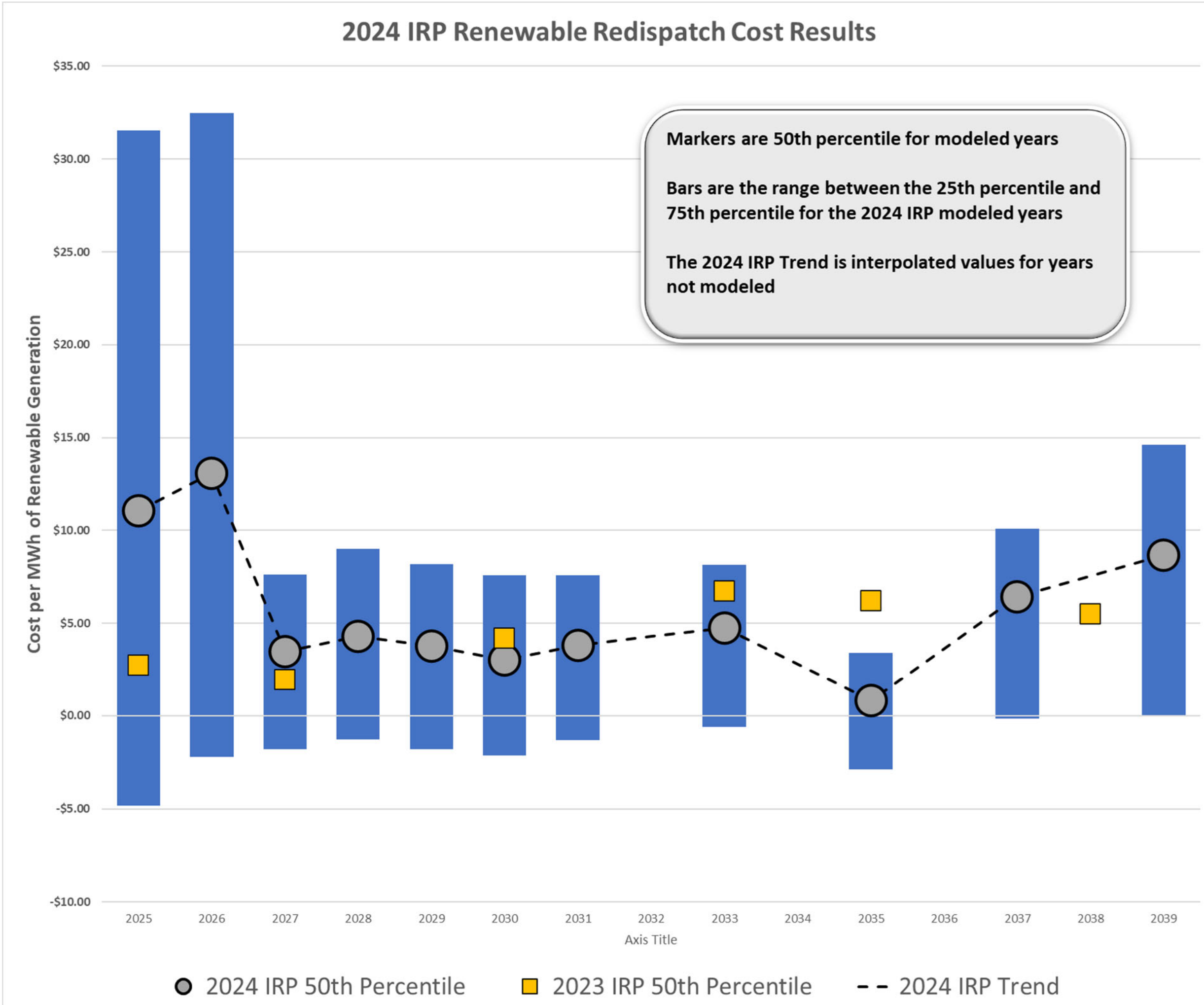
Figure 2 – Aurora Model Topology



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 VCEA with EPA Portfolio show that the hourly cost of regulating reserves gradually increases from $1.56/MWh in 2024 to over $10.00/MWh in 2030-2033 time frame. 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 2024 Plan 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. In 2034, modeled prices drop significantly as new gas and storage builds catch up to renewables build in PJM. This is in no small part because of the buildout of new natural gas units and energy story in the plans considered.

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. In all four primary Portfolios, the Company's supply of regulating reserves exceeded demand in each year, resulting in zero net market costs for each plan.

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

	2024 PJM Load Forecast Coincident Peak (CP)		Non-Coincident Peak (NCP)	
Year	DOM Zone Summer Forecast	LSE Equivalent	DOM Zone Summer Forecast	LSE Equivalent
2024	22,134	17,353	22,781	17,901
2025	23,021	17,497	23,691	18,065
2026	24,915	18,147	25,627	18,751
2027	26,731	18,465	27,487	19,106
2028	29,044	18,870	29,800	19,511
2029	31,023	19,318	31,776	19,956
2030	32,700	19,787	33,472	20,441
2031	34,139	20,280	34,911	20,934
2032	35,520	20,875	36,288	21,526
2033	36,856	21,504	37,673	22,196
2034	38,194	22,245	39,019	22,944
2035	39,498	23,074	40,279	23,736
2036	40,756	23,985	41,482	24,600
2037	41,953	24,849	42,742	25,518
2038	43,175	25,708	44,023	26,427
2039	44,538	26,623	45,445	27,392

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

IRP Unit Name	Nameplate MW
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
Brunswick	1,472.2
Chesapeake CT 1, 4, 6	51.1
Chesapeake PPA	118
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
Elizabeth River 1	129.6
Elizabeth River 2	129.6
Elizabeth River 3	129.6
Gaston Hydro	177.6
Gordonsville 1	150.2
Gordonsville 2	150.2
Grassfield Solar	20.0
Gravel Neck 1-2	40.1
Gravel Neck 3	91.9
Gravel Neck 4	91.9
Gravel Neck 5	91.9
Gravel Neck 6	91.9
Greensville	1,773.3
Hopewell	71.1
Ladysmith 1	178.5
Ladysmith 2	178.5
Ladysmith 3	178.5
Ladysmith 4	178.5
Ladysmith 5	178.5
Lowmoor CT 1-4	82.8
Mount Storm 1	570.2
Mount Storm 2	570.2

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

IRP Unit Name	Nameplate MW
Mount Storm 3	522.0
Mount Storm CT	18.5
Norge Solar	20
North Anna 1	979.7
North Anna 2	979.7
North Anna Hydro	1.0
Northern Neck CT 1-4	82.8
Pleasant Hill PPA	20
Possum Point 6	613.0
Possum Point CT 1-6	96.0
Remington 1	178.5
Remington 2	170.0
Remington 3	178.5
Remington 4	178.5
Roanoke Rapids Hydro	100.0
Rosemary	180.0
Sadler Solar	100.0
Scott Solar	17.3
Solidago Solar	20
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
Walnut Solar	130.0
Warren	1,472.2
Water Strider PPA	80.0
Watlington PPA	20.0
Westmoreland PPA	19.9
Whitehouse Solar	20
Winterberry Solar	20
Woodland Solar	19

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
Bath County 1	VA	Intermediate	Pumped Storage	1985	301
Bath County 2	VA	Intermediate	Pumped Storage	1985	301
Bath County 3	VA	Intermediate	Pumped Storage	1985	301
Bath County 4	VA	Intermediate	Pumped Storage	1985	301
Bath County 5	VA	Intermediate	Pumped Storage	1985	301
Bath County 6	VA	Intermediate	Pumped Storage	1985	301
Bear Garden	VA	Baseload/Intermediate	Natural Gas	2011	622
Brunswick	VA	Baseload/Intermediate	Natural Gas	2016	1,401
Chesapeake CT 1, 4, 6	VA	Peak	Light Oil	1967	39
Chesterfield 7	VA	Intermediate	Natural Gas	1990	191
Chesterfield 8	VA	Intermediate	Natural Gas	1992	195
Clover 1	VA	Intermediate	Coal	1995	220
Clover 2	VA	Intermediate	Coal	1996	219
Colonial Trail West	VA	Intermittent	Solar	2019	77
CVOW (Demonstration)	VA	Intermittent	Wind	2020	3
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
Gaston Hydro	NC	Intermittent	Hydro	1963	220
Gordonsville 1	VA	Intermediate	Natural Gas	1994	104
Gordonsville 2	VA	Intermediate	Natural Gas	1994	104
Grassfield Solar	VA	Intermittent	Solar	2022	7
Gravel Neck 1-2	VA	Peak	Light Oil	1970	28
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
Greensville	VA	Baseload/Intermediate	Natural Gas	2018	1,588
Hopewell	VA	Baseload	Biomass	1989	51
Ladysmith 1	VA	Peak	Natural Gas	2001	151
Ladysmith 2	VA	Peak	Natural Gas	2001	151
Ladysmith 3	VA	Peak	Natural Gas	2008	160

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 4	VA	Peak	Natural Gas	2008	160
Ladysmith 5	VA	Peak	Natural Gas	2009	161
Lowmoor CT 1-4	VA	Peak	Light Oil	1971	48
Mount Storm 1	WV	Baseload	Coal	1965	544
Mount Storm 2	WV	Baseload	Coal	1966	553
Mount Storm 3	WV	Baseload	Coal	1973	520
Mount Storm CT	WV	Peak	Light Oil	1967	11
North Anna 1	VA	Baseload	Nuclear	1978	838
North Anna 2	VA	Baseload	Nuclear	1980	835
North Anna Hydro	VA	Intermittent	Hydro	1987	1
Northern Neck CT 1-4	VA	Peak	Light Oil	1971	47
Possum Point 6	VA	Baseload/Intermediate	Natural Gas	2003	573
Possum Point CT 1-6	VA	Peak	Light Oil	1968	72
Water Strider PPA	VA	Intermittent	Solar	2021	29
Westmoreland PPA	VA	Intermittent	Solar	2021	7
Remington 1	VA	Peak	Natural Gas	2000	150
Remington 2	VA	Peak	Natural Gas	2000	151
Remington 3	VA	Peak	Natural Gas	2000	152
Remington 4	VA	Peak	Natural Gas	2000	151
Roanoke Rapids Hydro	NC	Intermittent	Hydro	1955	95
Rosemary	NC	Peak	Light Oil	1990	155
Sadler Solar	VA	Intermittent	Solar	2021	55
Scott Solar	VA	Intermittent	Solar	2016	10
Southampton	VA	Baseload	Biomass	1992	51
Spring Grove	VA	Intermittent	Solar	2021	53
Surry 1	VA	Baseload	Nuclear	1972	838
Surry 2	VA	Baseload	Nuclear	1973	838
Sycamore Solar	VA	Intermittent	Solar	2023	14
Virginia City Hybrid Energy Center	VA	Baseload/Intermediate	Coal	2012	610
Warren	VA	Baseload/Intermediate	Natural Gas	2014	1,381
Whitehouse Solar	VA	Intermittent	Solar	2016	11
Woodland Solar	VA	Intermittent	Solar	2016	11
Norge Solar	VA	Intermittent	Solar	2023	7
Chesapeake PPA	VA	Intermittent	Solar	2024	41
Pleasant Hill PPA	VA	Intermittent	Solar	2023	7
Rivanna PPA	VA	Intermittent	Solar	2024	4

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
Watlington PPA	VA	Intermittent	Solar	2023	7
Wythe 2 PPA	VA	Intermittent	Solar	2024	26
Black Bear Distributed	VA	Intermittent	Solar	2023	1
Springfield Distributed	VA	Intermittent	Solar	2024	1
Stratford PPA	VA	Intermittent	Solar	2023	8
Camellia Solar	VA	Intermittent	Solar	2024	11
Fountain Creek Solar	VA	Intermittent	Solar	2024	44
Otter Creek Solar	VA	Intermittent	Solar	2024	33
Piney Creek Base Solar	VA	Intermittent	Solar	2023	44
Quillwort Solar	VA	Intermittent	Solar	2024	10
Sebera Solar	VA	Intermittent	Solar	2024	10
Solidago Solar	VA	Intermittent	Solar	2023	11
Winterberry Solar	VA	Intermittent	Solar	2023	11
Cox Storage PPA	VA	Peak	Grid	2024	3
Sinai Storage PPA	VA	Peak	Grid	2024	2
Dry Bridge Storage	VA	Peak	Grid	2023	9
Cavalier PPA	VA	Intermittent	Solar	2024	8
Dulles Tied Storage	VA	Peak	Grid	2024	21
Subtotal - Base					5,118
Subtotal - Baseload/Intermediate					6,175
Subtotal - Intermediate					2,840
Subtotal - Peak					2,805
Subtotal - Intermittent					869
Total					17,807

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

(1) Exisiting generators as of 2024

(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]					
Alexandria/Arlington - Covanta	VA	MSW	21,000	1/29/1988	1/28/2023
Brasfield Dam	VA	Hydro	2,800	10/12/1993	Auto renew
Suffolk Landfill	VA	Methane	3,280	8/1/2020	3/31/2022
Columbia Mills	VA	Hydro	343	2/7/1985	Auto renew
Lakeview (Swift Creek) Dam	VA	Hydro	400	11/26/2008	Auto renew
MeadWestvaco (formerly Westvaco)	VA	Coal/Biomass	140,000	11/3/1982	8/25/2028
Banister Dam	VA	Hydro	1,785	9/28/2008	Auto renew
Weyerhaeuser/Domtar	NC	Coal/biomass	28,400[2]	7/27/1991	Auto renew
Smurfit-Stone Container	VA	Coal/biomass	48,400[3]	3/21/1981	Auto renew
Burnshire Dam	VA	Hydro	100	7/11/2016	Auto renew
Cushaw Hydro	VA	Hydro	5,500	11/21/2018	11/20/2033
Essex Solar Center	VA	Solar	20,000	12/14/2017	12/13/2037
Rives Road Solar	VA	Solar	19,700	5/15/2020	5/14/2033
Pamplin Solar	VA	Solar	15,700	7/13/2020	7/12/2033
Hickory Solar	VA	Solar	32,000	9/8/2020	9/7/2033
Mt Jackson I Solar	VA	Solar	15,650	6/14/2021	6/13/2034
Hollyfield II Solar	VA	Solar	13,000	7/22/2021	7/21/2034
Buckingham II Solar	VA	Solar	20,000	7/28/2021	7/27/2034
Water Strider Solar	VA	Solar	80,000	5/15/2021	5/14/2041
Westmoreland County Solar	VA	Solar	20,000	10/22/2021	10/21/2041
Tredegar Solar	VA	Solar	480	11/18/2022	11/17/2032
Nokesville Solar	VA	Solar	14,000	11/22/2022	11/21/2035
W. E. Partners II	NC	Biomass	300	3/15/2012	Auto renew
Plymouth Solar	NC	Solar	5,000	10/4/2012	10/3/2027
W. E. Partners 1	NC	Biomass	100	4/26/2013	Auto renew
Dogwood Solar	NC	Solar	20,000	12/9/2014	12/8/2029
HXOap Solar	NC	Solar	20,000	12/16/2014	12/15/2029
Bethel Price Solar	NC	Solar	5,000	12/9/2014	12/8/2029
Jakana Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Lewiston Solar	NC	Solar	5,000	12/18/2014	12/17/2029
Williamston Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Windsor Solar	NC	Solar	5,000	12/17/2014	12/16/2029
510 REPP One Solar	NC	Solar	1,250	3/11/2015	3/10/2030
Everetts Wildcat Solar	NC	Solar	5,000	3/11/2015	3/10/2030
SolNC5 Solar	NC	Solar	5,000	5/12/2015	5/11/2030
Creswell Aligood Solar	NC	Solar	14,000	5/13/2015	5/12/2030
Two Mile Desert Road - SolNC1	NC	Solar	5,000	8/10/2015	8/9/2030
SolNCPower6 Solar	NC	Solar	5,000	11/1/2015	10/31/2030
Downs Farm Solar	NC	Solar	5,000	12/1/2015	11/30/2030
GKS Solar- SolNC2	NC	Solar	5,000	12/16/2015	12/15/2030
Windsor Cooper Hill Solar	NC	Solar	5,000	12/18/2015	12/17/2030
Green Farm Solar	NC	Solar	5,000	1/6/2016	1/5/2031
FAE X - Shawboro	NC	Solar	20,000	1/26/2016	1/25/2031
FAE XVII - Watson Seed	NC	Solar	20,000	1/28/2016	1/27/2031

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
Bradley PVI- FAE IX	NC	Solar	5,000	2/4/2016	2/3/2031
Conetoe Solar	NC	Solar	5,000	2/5/2016	2/4/2031
SolNC3 Solar-Sugar Run Solar	NC	Solar	5,000	2/5/2016	2/4/2031
Gates Solar	NC	Solar	5,000	2/8/2016	2/7/2031
Long Farm 46 Solar	NC	Solar	5,000	2/12/2016	2/11/2031
Battleboro Farm Solar	NC	Solar	5,000	2/17/2016	2/16/2031
Winton Solar	NC	Solar	5,000	2/8/2016	2/7/2031
SolNC10 Solar	NC	Solar	5,000	1/13/2016	1/12/2031
Tarboro Solar	NC	Solar	5,000	12/31/2015	12/30/2030
Bethel Solar	NC	Solar	4,400	3/3/2016	3/2/2031
Garysburg Solar	NC	Solar	5,000	3/18/2016	3/17/2031
Woodland Solar	NC	Solar	5,000	4/7/2016	4/6/2031
Gaston Solar	NC	Solar	5,000	4/18/2016	4/17/2031
TWE Kelford Solar	NC	Solar	4,700	6/6/2016	6/5/2031
FAE XVIII - Meadows	NC	Solar	20,000	6/9/2016	6/8/2031
Seaboard Solar	NC	Solar	5,000	6/29/2016	6/28/2031
Simons Farm Solar	NC	Solar	5,000	7/13/2016	7/12/2031
Whitakers Farm Solar	NC	Solar	3,400	7/20/2016	7/19/2031
MC1 Solar	NC	Solar	5,000	8/19/2016	8/18/2031
Williamston West Farm Solar	NC	Solar	5,000	8/23/2016	8/22/2031
River Road Solar	NC	Solar	5,000	8/23/2016	8/22/2031
White Farm Solar	NC	Solar	5,000	8/26/2016	8/25/2031
Hardison Farm Solar	NC	Solar	5,000	9/9/2016	9/8/2031
Modlin Farm Solar	NC	Solar	5,000	9/14/2016	9/13/2031
Battleboro Solar	NC	Solar	5,000	10/7/2016	10/6/2031
Williamston Speight Solar	NC	Solar	15,000	11/23/2016	11/22/2031
Barnhill Road Solar	NC	Solar	3,100	11/30/2016	11/29/2031
Hemlock Solar	NC	Solar	5,000	12/5/2016	12/4/2031
Leggett Solar	NC	Solar	5,000	12/14/2016	12/13/2031
Schell Solar Farm	NC	Solar	5,000	12/22/2016	12/21/2031
FAE XXXV - Turkey Creek	NC	Solar	13,500	1/31/2017	1/30/2027
FAE XXII - Baker PVI	NC	Solar	5,000	1/30/2017	1/29/2032
FAE XXI -Benthall Bridge PVI	NC	Solar	5,000	1/30/2017	1/29/2032
Aulander Hwy 42 Solar	NC	Solar	5,000	12/30/2016	12/29/2031
Floyd Road Solar	NC	Solar	5,000	6/19/2017	6/18/2032
Flat Meeks- FAE II	NC	Solar	5,000	10/27/2017	10/26/2032
HXNAir Solar One	NC	Solar	5,000	12/21/2017	12/20/2032
Cork Oak Solar	NC	Solar	20,000	12/29/2017	12/28/2027
Sunflower Solar	NC	Solar	16,000	12/29/2017	12/28/2027
Davis Lane Solar	NC	Solar	5,000	12/31/2017	12/30/2032
FAE XIX- American Legion PVI	NC	Solar	15,840	1/2/2018	1/1/2033
FAE XXV-Vaughn's Creek	NC	Solar	20,000	1/2/2018	1/1/2033
TWE Ahoskie Solar Project	NC	Solar	5,000	1/12/2018	1/11/2033
Cottonwood Solar	NC	Solar	3,000	1/25/2018	1/24/2033
Shiloh Hwy 1108 Solar	NC	Solar	5,000	2/9/2018	2/8/2033

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
Chowan Jehu Road Solar	NC	Solar	5,000	2/9/2018	2/8/2033
Phelps 158 Solar Farm	NC	Solar	5,000	2/26/2018	2/25/2033
Sandy Solar	NC	Solar	5,000	5/30/2018	5/29/2033
Northern Cardinal Solar	NC	Solar	2,000	6/29/2018	6/28/2033
Carl Friedrich Gauss Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Sun Farm VI Solar	NC	Solar	4,975	9/10/2018	9/9/2033
Sun Farm V Solar	NC	Solar	4,975	9/10/2018	9/9/2033
Citizens Hertford	NC	Solar	16,200	6/6/2019	6/5/2029
Camden Dam Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Mill Pond Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Jamesville Road	NC	Solar	5,000	9/10/2018	9/9/2033
North 301	NC	Solar	20,000	12/18/2019	12/17/2029
Five Forks	NC	Solar	20,000	12/23/2019	12/22/2029
Whitehurst PVI Solar	NC	Solar	10,000	3/13/2020	3/12/2035
FAE XXXIII - Grandy	NC	Solar	20,000	3/13/2020	3/12/2030
Alpha Value Solar	NC	Solar	5,000	7/9/2020	9/9/2033
FAE XXXIV - Underwood	NC	Solar	16,000	10/23/2020	10/22/2030
Highway -158 PVI	NC	Solar	9,000	11/10/2020	11/9/2030
Gliden Solar	NC	Solar	5,000	12/30/2020	9/9/2033
Sun Farm VIII	NC	Solar	3,975	12/17/2020	9/9/2033
Ryland Road Solar	NC	Solar	5,000	8/31/2021	9/9/2033
Windsor Hwy 17 Solar	NC	Solar	5,000	8/28/2021	9/9/2033
Hertford Solar	NC	Solar	10,000	8/3/2022	8/2/2027
Aditya Solar	VA	Solar	7,700	8/21/2023	8/20/1936
Watlington Solar	RUS	Solar	20,000	3/29/2023	3/28/2043
Chesapeake Solar	RUS	Solar	118,000	12/20/2023	12/19/2043
Pleasant Hill Solar	RUS	Solar	20,000	6/15/2023	6/14/2023
Stratford Solar	RUS	Solar	15,000	1/4/2023	1/3/2043

(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-3: Equivalent Availability Factor for VCEA with EPA

Company Name: Virginia Electric and Power Company

Schedule 8

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

	(ACTUAL)		(PROJECTED)																
Unit Name	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Altavista	71	77	64	70	87	88	85	85	85	85	85	84	84	84	84	84	84	84	84
Hopewell	20	80	79	71	78	77	77	77	77	77	77	76	76	76	76	76	76	76	76
Southampton	78	76	77	85	90	88	90	88	88	88	88	88	88	88	88	88	88	88	88
Clover 1	73	79	76	77	86	85	85	85	85	85	85	82	82	82	82	82	82	82	82
Clover 2	65	81	76	67	79	77	87	87	87	87	87	84	84	84	84	84	84	84	84
Mount Storm 1	76	59	67	70	84	80	80	80	80	80	80	79	79	79	79	79	79	79	79
Mount Storm 2	63	82	54	60	88	86	84	88	81	81	88	80	80	80	80	80	80	80	80
Mount Storm 3	58	62	58	74	64	88	86	90	83	83	90	83	83	83	83	83	83	83	83
Virginia City Hybrid Energy Center	69	63	74	71	92	84	82	97	97	97	97	88	88	88	88	88	88	88	88
Chesapeake CT 1, 4, 6	97	94	81	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1-2	98	95	92	96	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT 1-4	98	95	96	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	100	98	94	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	89	70	96	95	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT 1-6	100	87	95	93	98	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	89	73	75	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Bear Garden	87	73	81	79	84	82	78	87	87	87	87	82	82	82	82	82	82	82	82
Brunswick	88	69	57	77	89	80	85	89	85	85	89	80	80	80	80	80	80	80	80
Chesterfield 7	65	71	67	76	85	70	83	81	83	79	87	81	81	81	81	81	81	81	81
Chesterfield 8	44	70	75	80	80	80	71	80	75	80	84	77	77	77	77	77	77	77	77
Gordonsville 1	65	90	78	84	96	96	96	96	87	96	96	93	93	93	93	93	93	93	93
Gordonsville 2	67	84	83	67	94	87	96	87	96	96	96	93	93	93	93	93	93	93	93
Greensville	77	85	78	81	88	91	91	91	89	80	91	87	87	87	87	87	87	87	87
Possum Point 6	87	68	66	63	89	92	92	99	99	99	99	88	88	88	88	88	88	88	88
Warren	81	74	80	80	87	83	88	73	91	86	86	83	83	83	83	83	83	83	83
Darbytown 1	71	50	97	85	88	88	88	88	84	88	88	99	99	99	99	99	99	99	99
Darbytown 2	98	74	96	66	88	88	84	88	88	88	88	99	99	99	99	99	99	99	99
Darbytown 3	81	70	98	85	89	89	89	89	89	89	89	99	99	99	99	99	99	99	99
Darbytown 4	97	71	99	85	88	88	88	84	88	88	88	99	99	99	99	99	99	99	99
Elizabeth River 1	37	95	80	89	90	86	90	90	90	90	90	97	97	97	97	97	97	97	97
Elizabeth River 2	80	91	92	89	90	90	90	90	90	90	90	97	97	97	97	97	97	97	97
Elizabeth River 3	77	84	91	89	90	90	67	90	90	90	90	96	96	96	96	96	96	96	96
Gravel Neck 3	86	91	88	86	87	87	87	87	87	87	87	100	100	100	100	100	100	100	100
Gravel Neck 4	87	87	95	53	50	50	50	50	50	47	50	99	99	99	99	99	99	99	99
Gravel Neck 5	88	88	96	85	86	82	86	86	86	86	86	99	99	99	99	99	99	99	99
Gravel Neck 6	88	89	97	84	88	88	88	88	88	88	88	100	100	100	100	100	100	100	100
Ladysmith 1	92	88	75	83	93	86	92	92	92	92	92	90	90	90	90	90	90	90	90
Ladysmith 2	92	72	89	76	86	80	85	85	85	76	85	90	90	90	90	90	90	90	90
Ladysmith 3	92	89	84	82	79	84	82	76	84	84	84	90	90	90	90	90	90	90	90
Ladysmith 4	90	90	92	75	85	84	76	84	84	84	84	90	90	90	90	90	90	90	90
Ladysmith 5	77	89	92	75	85	84	79	84	76	84	84	90	90	90	90	90	90	90	90
Remington 1	94	77	91	84	85	84	79	84	76	84	84	89	89	89	89	89	89	89	89
Remington 2	94	92	83	65	77	81	81	81	81	81	81	90	90	90	90	90	90	90	90
Remington 3	93	92	84	81	84	74	83	83	83	83	83	90	90	90	90	90	90	90	90
Remington 4	90	91	79	77	86	80	85	85	85	76	85	89	89	89	89	89	89	89	89
North Anna 1	100	89	99	88	88	98	77	88	98	89	91	90	83	83	90	90	90	-	-
North Anna Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90	90
North Anna 2	87	80	87	98	88	77	98	88	89	98	91	83	90	83	90	90	90	90	90
Surry 1	100	85	99	81	86	98	85	89	98	79	89	-	-	-	-	-	-	-	-
Surry Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	91	91	91	91	91	91	91	91
Surry 2	91	100	84	88	98	85	85	98	79	90	98	83	-	-	-	-	-	-	-
Surry Unit 2 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	91	91	91	91	91	91	91
Bath County 1	90	72	88	44	78	97	97	74	97	97	97	88	88	88	88	88	88	88	88
Bath County 2	67	74	72	71	63	81	81	71	81	81	81	72	72	72	72	72	72	72	72
Bath County 3	81	95	68	75	90	68	90	90	78	90	90	81	81	81	81	81	81	81	81
Bath County 4	76	95	62	87	94	82	94	94	72	94	94	85	85	85	85	85	85	85	85
Bath County 5	97	97	81	62	97	98	85	97	97	85	97	88	88	88	88	88	88	88	88
Bath County 6	89	96	46	77	97	97	74	97	97	85	97	88	88	88	88	88	88	88	88
Combined Cycle 2x1	-	-	-	-	-	-	-	-	-	-	-	88	88	88	88	88	88	88	88
Combustion Turbine Brownfield 2X	-	-	-	-	-	-	-	-	-	-	-	100	92	92	92	92	92	92	92
Combustion Turbine Brownfield 4X	-	-	-	-	-	-	-	-	-	100	100	91	91	91	91	91	91	91	91
Nuclear - Small Modular Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	100	95	95	95	95	95

Notes:
(1) Equivalent availability factor for intermittent resources shown as a capacity factor.

Appendix 3B-4: Net Capacity Factor

Company Name: Virginia Electric and Power Company

Schedule 9

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

Unit Name	2021 (ACTUAL)	2022	2023 (PROJECTED)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Altavista	72.26	74.78	63.38	67.61	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Hopewell	68.59	79.61	77.22	68.75	75.00	74.63	74.63	74.66	74.63	74.63	74.63	73.04	73.00	73.00	73.00	73.04	73.00	73.00	71.56
Southampton	71.35	75.03	76.10	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Clover 1	10.90	8.28	2.64	40.00	40.00	40.00	18.43	17.88	13.51	21.68	14.05	8.22	10.42	14.05	13.37	6.54	12.09	19.16	9.37
Clover 2	12.34	8.18	3.82	40.00	40.00	40.00	20.46	20.23	15.26	24.15	15.82	10.30	12.48	15.23	15.23	8.67	14.58	21.62	11.00
Mount Storm 1	34.53	29.92	20.94	59.98	60.00	60.00	38.87	39.41	33.18	3.80	0.45	0.09	0.22	0.40	1.51	0.33	0.83	2.01	1.40
Mount Storm 2	37.94	36.14	24.93	52.88	60.00	60.00	45.83	45.00	38.08	3.16	1.06	0.36	0.54	0.93	2.96	0.78	1.96	5.65	2.23
Mount Storm 3	43.76	32.23	28.89	60.00	60.00	60.00	55.24	52.97	44.62	5.93	2.84	1.14	1.76	3.14	5.16	1.37	3.66	7.83	3.51
Virginia City Hybrid Energy Center	17.85	25.52	14.10	48.07	70.00	70.00	40.88	44.46	38.12	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Chesapeake CT 1, 4, 6	0.08	1.20	0.22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1-2	0.03	0.52	0.19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT 1-4	0.24	0.62	0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	0.03	0.07	0.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	1.50	4.80	0.37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT 1-6	0.13	0.57	0.09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	0.78	0.12	0.48	0.66	0.37	0.16	0.04	0.12	-	0.17	0.12	-	-	-	-	-	-	-	0.07
Bear Garden	56.99	44.19	55.48	68.55	68.63	68.66	68.75	68.47	68.67	68.71	68.75	68.61	68.81	68.78	68.80	67.79	68.83	68.83	61.24
Brunswick	71.94	59.96	52.58	74.86	85.81	77.64	81.58	84.52	78.79	78.62	79.50	73.78	75.18	74.82	73.67	71.22	72.75	73.32	67.54
Chesterfield 7	56.31	56.16	55.60	68.60	76.72	62.73	75.88	73.40	75.21	70.42	76.63	71.16	71.87	71.81	71.29	69.11	69.57	70.47	66.08
Chesterfield 8	60.64	57.14	62.49	72.27	72.37	72.32	62.89	72.60	67.12	72.52	74.83	68.86	68.79	68.80	68.75	67.79	67.89	68.01	65.99
Gordonsville 1	58.70	57.96	46.50	68.38	82.60	85.76	76.53	73.67	56.98	69.37	59.49	64.15	69.72	70.68	65.77	56.96	62.10	66.84	51.95
Gordonsville 2	45.87	49.04	49.64	54.26	81.78	78.77	80.63	70.60	67.76	71.68	62.23	67.52	71.73	72.35	68.70	59.69	65.55	69.80	53.79
Greensville	82.76	80.12	73.94	78.92	87.29	91.58	91.58	91.61	88.91	80.24	90.99	86.95	87.22	87.17	86.93	85.51	85.53	85.79	82.38
Possum Point 6	46.11	35.11	37.23	52.73	79.29	83.56	77.55	74.95	71.07	70.46	59.20	61.99	67.82	67.66	62.96	55.98	60.39	64.08	51.63
Warren	60.08	64.64	70.57	77.04	84.56	80.21	85.29	69.98	86.85	81.01	76.75	77.87	79.24	79.05	78.03	74.50	75.33	76.17	68.85
Darbytown 1	0.74	1.06	5.75	20.68	10.86	6.67	1.00	1.17	0.12	0.09	-	-	-	-	-	-	0.05	-	0.04
Darbytown 2	1.43	2.22	2.88	0.01	-	-	-	0.03	-	-	-	-	-	-	-	-	-	-	-
Darbytown 3	2.87	1.18	4.20	0.03	-	-	-	0.03	-	-	-	-	-	-	-	-	-	-	-
Darbytown 4	1.71	2.93	3.02	0.03	-	-	-	0.03	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	1.22	1.28	4.30	11.79	4.26	2.04	0.30	0.31	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 2	2.58	3.72	5.99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 3	0.85	1.49	1.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	1.75	1.74	1.37	24.10	8.69	5.14	0.74	0.94	0.08	-	-	-	-	-	-	-	0.05	-	0.01
Gravel Neck 4	0.32	0.93	2.47	0.03	-	-	-	0.03	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	1.03	0.95	4.85	0.03	-	-	-	0.03	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 6	0.29	0.58	3.24	0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	6.10	10.79	8.51	0.03	-	-	-	0.03	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	6.55	14.33	16.49	0.07	0.07	-	-	0.03	-	0.17	0.08	-	-	-	-	-	-	-	-
Ladysmith 3	5.29	10.28	7.71	0.05	0.03	-	-	0.03	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	10.50	17.60	12.39	40.40	37.79	36.51	7.83	8.86	3.59	12.05	7.29	6.23	6.34	10.55	9.12	3.39	6.21	11.39	4.49
Ladysmith 5	6.63	10.84	17.02	40.98	38.82	37.61	10.32	9.53	3.82	13.88	9.58	7.43	8.23	11.97	10.29	4.64	7.13	12.42	5.26
Remington 1	12.42	15.23	8.83	0.14	0.07	0.03	0.03	0.08	-	0.17	0.08	-	-	-	-	-	-	-	-
Remington 2	6.29	11.03	0.65	-	-	-	-	0.03	-	-	-	-	-	-	-	-	-	-	-
Remington 3	11.03	15.97	4.55	39.29	33.59	33.45	12.83	10.55	4.96	22.03	12.22	8.66	10.10	13.01	14.09	6.10	11.05	17.09	6.35
Remington 4	7.97	11.09	9.33	42.59	49.73	49.98	27.06	20.02	12.09	28.25	20.97	19.32	25.10	27.43	25.47	15.81	21.49	29.85	18.56
North Anna 1	83.32	90.14	101.30	86.21	86.86	96.30	75.33	86.39	96.30	87.17	88.99	88.76	81.78	81.29	88.73	88.76	88.73	-	-
North Anna Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88.73	88.73
North Anna 2	102.21	82.05	89.68	96.39	86.25	75.07	96.39	86.31	87.45	96.39	88.89	81.46	88.81	81.62	88.81	88.84	88.81	88.81	88.81
Surry 1	90.42	86.67	101.53	79.52	83.57	95.92	83.84	86.56	95.92	77.75	86.53	-	-	-	-	-	-	-	-
Surry Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	88.91	88.88	88.88	88.88	88.91	88.88	88.88	88.88
Surry 2	89.32	102.14	86.03	86.02	95.92	83.58	83.30	95.93	77.60	87.87	95.92	81.05	-	-	-	-	-	-	-
Surry Unit 2 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	88.88	88.88	88.88	88.91	88.88	88.88	88.88
Bath County 1	20.91	16.36	22.21	10.88	18.99	20.05	15.50	8.82	11.97	15.01	13.72	11.81	12.46	12.98	14.65	15.54	15.79	17.37	19.89
Bath County 2	8.28	16.48	18.60	16.46	13.04	15.07	12.02	7.50	9.11	11.91	11.30	11.89	11.03	10.47	13.91	13.16	15.62	14.92	18.22

Appendix 3B-4: Net Capacity Factor

Company Name: Virginia Electric and Power Company

Schedule 9

UNIT PERFORMANCE DATA

Net Capacity Factor (%)

	(ACTUAL)								(PROJECTED)										
Unit Name	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Bath County 3	12.91	19.04	10.76	16.55	18.48	13.25	12.95	9.80	8.86	13.89	13.30	12.18	12.50	12.07	13.79	15.03	17.46	17.82	20.20
Bath County 4	9.64	22.78	13.51	19.25	19.58	16.85	14.45	9.79	8.39	15.33	13.66	14.05	13.86	13.92	15.81	16.21	18.09	17.79	20.06
Bath County 5	11.45	20.51	16.92	14.72	20.40	19.20	12.72	10.85	11.14	12.49	14.15	14.63	13.94	13.65	17.39	17.34	18.78	18.08	22.54
Bath County 6	7.79	9.81	9.85	18.79	21.28	20.11	12.14	12.31	13.02	14.15	17.12	16.30	16.26	15.77	18.37	18.11	21.21	21.40	22.61
Combined Cycle 2x1	-	-	-	-	-	-	-	-	-	-	-	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
Combustion Turbine Brownfield 2X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.04	0.17	0.24	0.48	0.43
Combustion Turbine Brownfield 4X	-	-	-	-	-	-	-	-	-	8.82	4.09	1.38	1.89	4.38	4.13	1.33	2.63	5.21	2.12
Nuclear - Small Modular Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.65	90.67	90.65	90.65	90.65

Appendix 3B-5: Heat Rates

Company Name: Virginia Electric and Power Company | Schedule 10

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh)

	(ACTUAL)			(PROJECTED)														
Unit Name	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Altavista	16.39	16.56	16.56	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03
Hopewell	17.39	16.53	16.83	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88	11.88
Southampton	17.47	17.08	16.46	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19
Clover 1	11.46	11.16	12.14	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78	9.78
Clover 2	11.20	10.97	11.63	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60
Mount Storm 1	10.32	10.49	10.89	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18	10.18
Mount Storm 2	10.31	10.51	10.87	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80	9.80
Mount Storm 3	9.83	10.94	11.08	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65
Virginia City Hybrid Energy Center	10.98	10.46	11.84	10.02	10.02	10.02	10.02	10.02	10.02	10.02	10.02	10.02	10.02	10.02	10.02	10.02	10.02	10.02	10.02
Chesapeake CT 1, 4, 6	18.18	16.45	18.10	15.56	15.56	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1-2	19.24	15.72	18.02	15.88	15.88	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT 1-4	17.24	18.00	18.69	17.73	17.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	13.99	14.68	13.76	14.62	14.62	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	17.05	16.72	16.29	17.17	17.17	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT 1-6	15.98	18.27	16.66	17.43	17.43	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	9.74	11.28	10.41	8.73	8.73	8.73	8.73	8.73	8.73	8.73	8.73	8.73	8.73	8.73	8.73	8.73	8.73	8.73	8.73
Bear Garden	7.31	7.27	7.10	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08
Brunswick	7.04	7.02	6.96	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86	6.86
Chesterfield 7	7.69	7.76	7.67	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21
Chesterfield 8	7.36	7.73	7.57	6.96	6.96	6.96	6.96	6.96	6.96	6.96	6.96	6.96	6.96	6.96	6.96	6.96	6.96	6.96	6.96
Gordonsville 1	8.14	8.63	8.65	8.23	8.23	8.23	8.23	8.23	8.23	8.23	8.23	8.23	8.23	8.23	8.23	8.23	8.23	8.23	8.23
Gordonsville 2	8.36	8.35	8.44	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Greensville	6.72	6.51	6.45	6.61	6.63	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66
Possum Point 6	7.15	7.50	7.45	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77	7.77
Warren	6.89	6.90	6.76	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08	7.08
Darbytown 1	13.28	12.58	13.12	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45
Darbytown 2	12.89	12.49	12.90	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45
Darbytown 3	12.90	12.44	12.94	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45
Darbytown 4	12.88	12.74	13.02	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45	12.45
Elizabeth River 1	12.55	12.32	12.47	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37
Elizabeth River 2	12.63	12.99	12.19	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37
Elizabeth River 3	12.16	12.21	13.39	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37	12.37
Gravel Neck 3	13.14	12.99	12.73	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87
Gravel Neck 4	13.21	12.76	13.26	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87
Gravel Neck 5	13.60	13.53	13.67	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87
Gravel Neck 6	13.09	13.26	12.95	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87	12.87
Ladysmith 1	10.90	10.06	10.94	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28	10.28
Ladysmith 2	10.67	9.71	10.65	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92	9.92
Ladysmith 3	10.16	9.67	10.84	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20
Ladysmith 4	10.18	9.90	10.95	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20
Ladysmith 5	10.00	9.55	10.87	10.14	10.14	10.14	10.14	10.14	10.14	10.14	10.14	10.14	10.14	10.14	10.14	10.14	10.14	10.14	10.14
Remington 1	10.06	9.70	10.50	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51	9.51
Remington 2	10.32	10.33	11.16	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32
Remington 3	10.22	10.33	11.44	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26
Remington 4	10.42	10.42	10.45	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35
North Anna 1	10.40	10.39	10.34	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	10.40	-	-
North Anna Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.40	10.40
North Anna 2	10.35	10.34	10.35	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42
Surry 1	10.32	10.29	10.32	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	-	-	-	-	-	-	-	-
Surry Unit 1 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Surry 2	10.23	10.30	10.26	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	-	-	-	-	-	-	-
Surry Unit 2 Nuclear Extension	-	-	-	-	-	-	-	-	-	-	-	-	10.31	10.31	10.31	10.31	10.31	10.31	10.31

Appendix 3B-5: Heat Rates

Company Name: Virginia Electric and Power Company

Schedule 10

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh)

		(ACTUAL)								(PROJECTED)									
Unit Name	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Combined Cycle 2x1	-	-	-	-	-	-	-	-	-	-	-	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25
Combustion Turbine Brownfield 2X	-	-	-	-	-	-	-	-	-	-	-	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83
Combustion Turbine Brownfield 4X	-	-	-	-	-	-	-	-	-	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19
Nuclear - Small Modular Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	11.72	11.72	11.72	11.72	11.72	11.72

Appendix 3B-6: Existing Capacity (for VCEA with EPA)

Company Name: Virginia Electric and Power Company

Schedule 7

CAPACITY DATA

	2021	2022 (ACTUAL)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
I. Firm Capacity (MW)[(1)(4)]																			
a. Nuclear[(5)]	3,357	3,357	3,356	3,349	3,349	3,244	3,244	3,244	3,278	3,244	3,278	3,278	3,210	3,176	3,176	3,176	3,176	3,176	3,176
b. Biomass[(3)]	153	153	153	214	214	165	163	165	167	165	167	169	164	160	160	160	160	160	160
c. Coal	3,684	3,680	2,666	2,601	2,601	2,232	2,232	2,232	2,259	2,259	2,285	2,285	2,206	2,099	2,099	2,099	2,099	2,099	2,099
d. Heavy Fuel Oil	787	787	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
e. Light Fuel Oil	584	584	584	387	387	91	92	93	96	96	98	98	97	95	95	95	95	95	95
f. Natural Gas-Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Natural Gas-Combined Cycle	6,266	6,266	6,287	6,169	6,169	4,876	4,949	5,028	5,138	5,138	5,242	6,320	6,257	6,123	6,123	7,163	7,163	7,163	7,163
h. Natural Gas-Turbine	2,051	2,051	2,051	2,391	2,391	1,961	1,961	1,985	1,985	2,010	2,035	2,060	2,060	2,060	2,060	2,060	2,060	2,060	2,060
i. Hydro-Conventional	317	317	294	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316
j. Pumped Storage & Battery	1,809	1,809	1,827	1,825	1,825	1,263	1,209	1,263	1,209	1,227	1,136	1,135	1,134	1,133	1,132	1,132	1,131	1,130	1,129
k. Renewable	128	224	290	842	861	206	151	132	131	112	94	94	93	74	74	56	56	56	56
l. Total Company Firm Capacity	19,137	19,228	17,510	18,093	18,112	14,354	14,317	14,459	14,579	14,567	14,652	15,755	15,536	15,236	15,235	16,256	16,255	16,255	16,254
m. Other (PPA)	-	64	-	142	142	142	121	121	14	14	14	14	14	14	14	14	14	14	14
n. Storage PPA	-	-	-	11	10	7	7	7	7	6	5	5	5	5	5	5	4	4	4
o. Renewable PPA	-	-	84	219	248	79	66	61	61	56	52	52	52	47	47	42	42	42	42
p. Total	19,137	19,293	17,594	18,465	18,512	14,583	14,510	14,648	14,661	14,644	14,723	15,826	15,607	15,302	15,301	16,317	16,316	16,315	16,314
II. Firm Capacity Mix (%)[(2)]																			
a. Nuclear	17.5%	17.4%	19.1%	18.1%	18.1%	22.2%	22.4%	22.1%	22.4%	22.2%	22.3%	20.7%	20.6%	20.8%	20.8%	19.5%	19.5%	19.5%	19.5%
b. Biomass(3)	0.8%	0.8%	0.9%	1.2%	1.2%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
c. Coal	19.3%	19.1%	15.2%	14.1%	14.1%	15.3%	15.4%	15.2%	15.4%	15.4%	15.5%	14.4%	14.1%	13.7%	13.7%	12.9%	12.9%	12.9%	12.9%
d. Heavy Fuel Oil	4.1%	4.1%	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%	0.0%	0.0%	0.0%
e. Light Fuel Oil	3.1%	3.0%	3.3%	2.1%	2.1%	0.6%	0.6%	0.6%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
f. Natural Gas-Boiler	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%	0.0%	0.0%	0.0%	0.0%	0.0%
g. Natural Gas-Combined Cycle	32.7%	32.5%	35.7%	33.4%	33.3%	33.4%	34.1%	34.3%	35.0%	35.1%	35.6%	39.9%	40.1%	40.0%	40.0%	43.9%	43.9%	43.9%	43.9%
h. Natural Gas-Turbine	10.7%	10.6%	11.7%	13.0%	12.9%	13.4%	13.5%	13.6%	13.5%	13.7%	13.8%	13.0%	13.2%	13.5%	13.5%	12.6%	12.6%	12.6%	12.6%
i. Hydro-Conventional	1.7%	1.6%	1.7%	1.7%	1.7%	2.2%	2.2%	2.2%	2.2%	2.2%	2.1%	2.0%	2.0%	2.1%	2.1%	1.9%	1.9%	1.9%	1.9%
j. Pumped Storage & Battery	9.5%	9.4%	10.4%	9.9%	9.9%	8.7%	8.3%	8.6%	8.2%	8.4%	7.7%	7.2%	7.3%	7.4%	7.4%	6.9%	6.9%	6.9%	6.9%
k. Renewable	0.7%	1.2%	1.7%	4.6%	4.7%	1.4%	1.0%	0.9%	0.9%	0.8%	0.6%	0.6%	0.6%	0.5%	0.5%	0.3%	0.3%	0.3%	0.3%
l. Total Company Firm Capacity	100.0%	99.7%	99.5%	98.0%	97.8%	98.4%	98.7%	98.7%	99.4%	99.5%	99.5%	99.6%	99.5%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%
m. Other (PPA)	0.0%	0.3%	0.0%	0.8%	0.8%	1.0%	0.8%	0.8%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
n. Storage PPA	0.0%	0.0%	0.0%	0.1%	0.1%	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%
o. Renewable PPA	0.0%	0.0%	0.5%	1.2%	1.3%	0.5%	0.5%	0.4%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
p. Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Net dependable annual firm capability during peak season.

(2) Each item in Section I as a percent of line "p." (Total).

(3) Includes current estimates for renewable capacity by VCHEC.

(4) Firm capacity as of model date 2024.

(5) Including nuclear extensions.

Appendix 3B-7: Energy Generation by Type (GWh) for VCEA with EPA

Company Name: Virginia Electric and Power Company

Schedule 2

GENERATION

	(ACTUALS)		(PROJECTED)																
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
I. System Output (GWh)																			
a. Nuclear	26,788	26,542	27,827	26,602	26,882	26,755	25,825	27,155	27,234	26,609	27,470	26,004	26,556	25,976	29,213	31,436	33,469	35,597	37,725
b. Biomass(1)	1,055	1,135	1,058	1,261	1,442	1,441	1,281	1,304	1,266	1,101	1,101	1,096	1,093	1,093	1,093	1,096	1,093	1,093	1,086
c. Coal	7,893	7,612	4,743	12,216	13,615	13,615	9,447	9,515	7,970	1,893	1,176	830	956	1,170	1,404	808	1,216	1,918	1,127
d. Heavy Fuel Oil	49	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
e. Light Fuel Oil	130	271	41	10	6	3	1	2	-	3	2	-	-	-	-	-	-	-	1
f. Natural Gas-Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Natural Gas-Combined Cycle	35,685	33,087	32,894	42,819	48,538	47,491	48,321	46,691	47,101	45,199	45,653	49,195	49,936	49,860	49,162	52,178	52,796	53,352	49,514
h. Natural Gas-Turbine	997	1,537	1,448	3,165	2,803	2,675	950	817	394	1,980	1,153	787	956	1,381	1,307	633	1,016	1,691	835
i. Hydro-Conventional	661	363	401	614	612	612	612	614	612	612	612	614	612	612	612	614	612	612	612
j. Pumped Storage & Battery	1,854	2,772	2,427	2,587	2,979	2,827	2,215	1,549	1,595	2,085	2,123	2,171	2,240	2,304	2,786	2,985	3,462	3,726	4,404
k. Renewable	804	786	950	1,232	1,838	2,693	13,660	14,595	16,701	18,634	20,710	22,753	24,638	29,115	31,235	33,041	34,684	36,379	46,181
l. Total Generation	75,917	74,137	71,788	90,506	98,715	98,111	102,312	102,243	102,872	98,114	100,000	103,450	106,987	111,511	116,812	122,792	128,348	134,367	141,484
m. Purchased Power (PPAs)	2,711	2,718	2,847	1,941	2,283	2,619	3,373	3,142	2,526	2,556	2,592	2,640	2,683	2,734	2,980	3,230	3,470	3,715	3,894
n. Purchased Power (Battery Storage)	-	-	-	-	41	263	387	1,047	1,558	2,103	2,549	2,965	3,365	3,760	4,130	4,441	4,750	5,002	5,225
o. Purchased Power (Market / PJM)	13,239	20,010	20,813	9,034	7,285	8,905	7,341	8,227	11,383	12,350	12,343	12,067	14,388	14,536	14,712	15,116	14,908	14,935	14,801
p. Less Pumping Energy	(2,369)	(3,446)	(3,052)	(3,222)	(3,759)	(3,827)	(3,200)	(3,139)	(3,788)	(5,034)	(5,586)	(6,116)	(6,652)	(7,177)	(8,196)	(8,787)	(9,722)	(10,352)	(11,374)
q. Less Other Sales(2)	(492)	(164)	(91)	(5,110)	(6,409)	(4,015)	(4,708)	(2,916)	(3,097)	(1,159)	(780)	(393)	(235)	(173)	(145)	(455)	(407)	(390)	(831)
s. Total System Firm Energy Req.	89,006	93,256	92,306	93,148	98,156	102,056	105,505	108,603	111,454	108,930	111,117	114,613	120,535	125,190	130,293	136,337	141,347	147,277	153,200
II. Energy Supplied by Competitive Service Providers	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	N/A

(1) Includes current estimates for renewable energy generation by VCHEC.

(2) Include all sales or delivery transactions with other electric utilities, i.e., firm or economy sales, etc.

Appendix 3B-8: Solar and Wind Generating Facilities Since July 1, 2018

Project Name	Status[1]	Nameplate (MWac)	In Service Date	Type	Cost Recovery Mechanism
Hollyfield Solar	Operational	17	2018	Company-build	Ring-Fence
Montross Solar	Operational	20	2018	Company-build	Ring-Fence
Pecan Solar	Operational	74.9	2018	Company-build	Ring-Fence
Puller Solar	Operational	15	2018	Company-build	Ring-Fence
Colonial Trail West Solar	Operational	142	2019	Company-build	RAC
Gloucester Solar	Operational	20	2019	Company-build	Ring-Fence
Gutenberg Solar	Operational	80	2019	Company-build	Ring-Fence
Chestnut Solar	Operational	75	2020	Company-build	Ring-Fence
Coastal VA Offshore Wind (CVOW) Demonstration	Operational	12	2020	Company-build	Fuel / Base
Grasshopper Solar	Operational	80	2020	Company-build	Ring-Fence
Spring Grove 1 Solar	Operational	98	2020	Company-build	RAC
Hickory Solar*	Operational	32	2020	PPA	Fuel / Base
Pamplin Solar*	Operational	15.7	2020	PPA	Fuel / Base
Rives Road Solar*	Operational	20	2020	PPA	Fuel / Base
Bedford Solar	Operational	70	2021	Company-build	Ring-Fence
Belcher Solar	Operational	88	2021	Company-build	Ring-Fence
Rochambeau Solar	Operational	20	2021	Company-build	Ring-Fence
Sadler Solar	Operational	100	2021	Company-build	RAC
Buckingham Solar II*	Operational	20	2021	PPA	Fuel / Base
Hollyfield Solar II*	Operational	13	2021	PPA	Fuel / Base
Mount Jackson Solar I*	Operational	15.65	2021	PPA	Fuel / Base
Water Strider Solar	Operational	80	2021	PPA	Fuel / Base
Westmoreland Solar	Operational	20	2021	PPA	Fuel / Base
Acorn Solar	Operational	1.4	2022	Company-build	Ring-Fence
Fort Powhatan Solar	Operational	150	2022	Company-build	Ring-Fence
Grassfield Solar	Operational	20	2022	Company-build	RAC
Maplewood Solar	Operational	120	2022	Company-build	Ring-Fence
Pumpkinseed Solar	Operational	59.6	2022	Company-build	Ring-Fence
Nokesville Solar*	Operational	20	2022	PPA	Fuel / Base
Sycamore Solar	Operational	42.0	2023	Company-build	RAC
Black Bear Distributed	Operational	1.6	2023	Company-build	RAC
Norge Solar	Operational	20.0	2023	Company-build	RAC
Piney Creek Solar	Operational	80.0	2023	Company-build	RAC
Solidago Solar	Operational	20.0	2023	Company-build	RAC
Winterberry Solar	Operational	20.0	2023	Company-build	RAC
Aditya Solar*	Operational	11.0	2023	PPA	Fuel / Base
Chesapeake Solar	Operational	118.0	2023	PPA	RAC
Pleasant Hill Solar	Operational	20.0	2023	PPA	RAC
Stratford Solar	Operational	15.0	2023	PPA	RAC
Watlington Solar	Operational	20.0	2023	PPA	RAC
Otter Creek Solar	Operational	60.0	2024	Company-build	RAC
Springfield Distributed	Operational	2.0	2024	Company-build	RAC
Endless Caverns Solar*	Operational	31.4	2024	PPA	Fuel / Base
Cavalier Solar	Operational	240.0	2024	PPA	RAC
Bookers Mill Solar	Under Construction	127.0	2024 (proj.)	Company-build	RAC
Camellia Solar	Under Construction	20	2024 (proj.)	Company-build	RAC
Fountain Creek Solar	Under Construction	80	2024 (proj.)	Company-build	RAC
Quillwort Solar	Under Construction	18	2024 (proj.)	Company-build	RAC
Sebera Solar	Under Construction	18	2024 (proj.)	Company-build	RAC
Bridleton Solar	Under Construction	20	2024 (proj.)	Company-build	RAC
Kings Creek Solar	Under Construction	20	2024 (proj.)	Company-build	RAC
Augusta Solar	Under Construction	105.0	2024 (proj.)	PPA	RAC
Cox Solar	Under Construction	16.0	2024 (proj.)	PPA	RAC
Sinai Solar	Under Construction	9.9	2024 (proj.)	PPA	RAC
Jarratt Solar	Under Construction	48.4	2024 (proj.)	PPA	RAC
New Kent Solar*	Under Construction	20	2024 (proj.)	PPA	Fuel / Base
Rivanna Solar	Under Construction	12.5	2024 (proj.)	PPA	RAC
Wythe Solar	Under Construction	75	2024 (proj.)	PPA	RAC
Ivy Landfill Distributed	Under Construction	3	2025 (proj.)	Company-build	RAC
Winterpock Solar	Under Construction	20	2025 (proj.)	Company-build	RAC
North Ridge Solar	Under Construction	20	2025 (proj.)	Company-build	RAC
Racefield Distributed	Under Construction	3	2025 (proj.)	Company-build	RAC

Appendix 3B-8: Solar and Wind Generating Facilities Since July 1, 2018

Project Name	Status[1]	Nameplate (MWac)	In Service Date	Type	Cost Recovery Mechanism
Surry Solar	Under Construction	20	2025 (proj.)	PPA	RAC
Switchgrass Solar	Under Construction	69	2025 (proj.)	PPA	RAC
Dulles Solar	Under Construction	100	2026 (proj)	Company-build	RAC
Sweet Sue Solar	Under Construction	73.0	2026 (proj.)	Company-build	RAC
Southern Virginia Solar	Under Construction	125	2026 (proj.)	Company-build	RAC
Walnut Solar	Under Construction	149.9	2026 (proj.)	Company-build	RAC
Cerulean Solar	Under Construction	62	2026 (proj.)	Company-build	RAC
Coastal VA Offshore Wind (CVOW)	Under Construction	2587.0	2026 (proj.)	Company-build	RAC
Courthouse Solar	Under Construction	167.0	2026 (proj.)	Company-build	RAC
Moon Corner Solar	Under Construction	60	2026 (proj.)	Company-build	RAC
360 Solar 1 Solar	Under Construction	26	2026 (proj.)	PPA	RAC
360 Solar 2 Solar	Under Construction	26	2026 (proj.)	PPA	RAC
Groves Solar	Under Construction	16.2	2026 (proj.)	PPA	RAC
Blue Ridge	Under Construction	95	2026 (proj.)	Company-build	RAC
Beldale	Under Construction	57	2026 (proj.)	Company-build	RAC
Michaux	Under Construction	50	2026 (proj.)	Company-build	RAC

[1]Under Construction Status may include Pre-Construction activities for Company-build projects.

* Variable pricing based on PJM energy and capacity prices.

Appendix 3B-9: Energy Generation by Type (%) for VCEA with EPA

Company Name: Virginia Electric and Power Company

Schedule 3

GENERATION

	(ACTUAL)			(PROJECTED)															
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
III. System Output Mix (%)																			
a. Nuclear	30.1%	28.5%	30.1%	28.6%	27.4%	26.2%	24.5%	25.0%	24.4%	24.4%	24.7%	22.7%	22.0%	20.7%	22.4%	23.1%	23.7%	24.2%	24.6%
b. Biomass(1)	1.2%	1.2%	1.1%	1.4%	1.5%	1.4%	1.2%	1.2%	1.1%	1.0%	1.0%	1.0%	0.9%	0.9%	0.8%	0.8%	0.8%	0.7%	0.7%
c. Coal	8.9%	8.2%	5.1%	13.1%	13.9%	13.3%	9.0%	8.8%	7.2%	1.7%	1.1%	0.7%	0.8%	0.9%	1.1%	0.6%	0.9%	1.3%	0.7%
d. Heavy Fuel Oil	0.1%	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%	0.0%	0.0%	0.0%	0.0%
e. Light Fuel Oil	0.1%	0.3%	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%	0.0%	0.0%	0.0%
f. Natural Gas-Boiler	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%	0.0%	0.0%	0.0%	0.0%	0.0%
g. Natural Gas-Combined Cycle	40.1%	35.5%	35.6%	46.0%	49.4%	46.5%	45.8%	43.0%	42.3%	41.5%	41.1%	42.9%	41.4%	39.8%	37.7%	38.3%	37.4%	36.2%	32.3%
h. Natural Gas-Turbine	1.1%	1.6%	1.6%	3.4%	2.9%	2.6%	0.9%	0.8%	0.4%	1.8%	1.0%	0.7%	0.8%	1.1%	1.0%	0.5%	0.7%	1.1%	0.5%
i. Hydro-Conventional	0.7%	0.4%	0.4%	0.7%	0.6%	0.6%	0.6%	0.6%	0.5%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.4%	0.4%
j. Pumped Storage & Battery	2.1%	3.0%	2.6%	2.8%	3.0%	2.8%	2.1%	1.4%	1.4%	1.9%	1.9%	1.9%	1.9%	1.8%	2.1%	2.2%	2.4%	2.5%	2.9%
k. Renewable	0.9%	0.8%	1.0%	1.3%	1.9%	2.6%	12.9%	13.4%	15.0%	17.1%	18.6%	19.9%	20.4%	23.3%	24.0%	24.2%	24.5%	24.7%	30.1%
l. Total Generation	85.3%	79.5%	77.8%	97.2%	100.6%	96.1%	97.0%	94.1%	92.3%	90.1%	90.0%	90.3%	88.8%	89.1%	89.7%	90.1%	90.8%	91.2%	92.4%
m. Purchased Power (PPAs)	3.0%	2.9%	3.1%	2.1%	2.3%	2.6%	3.2%	2.9%	2.3%	2.3%	2.3%	2.3%	2.2%	2.2%	2.3%	2.4%	2.5%	2.5%	2.5%
n. Purchased Power (Battery Storage)	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.4%	1.0%	1.4%	1.9%	2.3%	2.6%	2.8%	3.0%	3.2%	3.3%	3.4%	3.4%	3.4%
o. Purchased Power (Market / PJM)	14.9%	21.5%	22.5%	9.7%	7.4%	8.7%	7.0%	7.6%	10.2%	11.3%	11.1%	10.5%	11.9%	11.6%	11.3%	11.1%	10.5%	10.1%	9.7%
p. Less Pumping Energy	-2.7%	-3.7%	-3.3%	-3.5%	-3.8%	-3.8%	-3.0%	-2.9%	-3.4%	-4.6%	-5.0%	-5.3%	-5.5%	-5.7%	-6.3%	-6.4%	-6.9%	-7.0%	-7.4%
q. Less Other Sales(2)	-0.6%	-0.2%	-0.1%	-5.5%	-6.5%	-3.9%	-4.5%	-2.7%	-2.8%	-1.1%	-0.7%	-0.3%	-0.2%	-0.1%	-0.1%	-0.3%	-0.3%	-0.3%	-0.5%
r. Total System Firm Energy Req.	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
IV. System Load Factor	59.9%	58.4%	58.9%	64.5%	64.8%	65.9%	66.6%	67.3%	68.0%	68.6%	69.2%	69.9%	70.4%	71.0%	71.5%	71.9%	72.6%	73.5%	74.2%

(1) Includes current estimates for renewable energy generation by VCHEC.

(2) Include all sales or delivery transactions with other electric utilities, i.e., firm or economy sales, etc.

Appendix 3B-10: Potential Unit Retirements for VCEA with EPA

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**	**2026**	**39**	**53**
Chesapeake GT1					15	
Chesapeake GT4					12	
Chesapeake GT6					12	
Lowmoor CT	**Covington, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2026**	**48**	**65**
Lowmoor GT1					12	
Lowmoor GT2					12	
Lowmoor GT3					12	
Lowmoor GT4					12	
Mount Storm CT	**Mt. Storm, WV**	**CombustionTurbine**	**Light Fuel Oil**	**2026**	**11**	**16**
Mt. Storm GT1					11	
Northern Neck CT	**Warsaw, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2026**	**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**	**2026**	**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: Virginia Electric and Power Company — **Schedule 13**

UNIT PERFORMANCE DATA[1][2]

Unit Size (MW) Uprate and Derate

Unit Name	2021 (ACTUAL)	2022 (ACTUAL)	2023 (PROJECTED)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick County CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 8 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 2 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Greensville CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6 CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 3B-11 Planned Changes to Existing Generation Units

Company Name: Virginia Electric and Power Company — **Schedule 13**

UNIT PERFORMANCE DATA(1)(2)

Unit Size (MW) Uprate and Derate

	(ACTUAL)			(PROJECTED)															
Unit Name	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
North Anna 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE1_PPA_Chesapeake	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE1_PPA_Pleasant Hill	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE1_PPA_Rivanna	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE1_PPA_Watlington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE1_PPA_Wythe 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2 PPA_Stratford	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PPA_Water Strider	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PPA_Westmoreland	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE1_Grassfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE1_Norge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE1_Sycamore Creek	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2 DER Black Bear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2 DER Springfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Camellia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Fountain Creek	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Otter Creek	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Piney Creek Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Powhatan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Sebera	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Solidago	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Winterberry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Wind_CVOW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
US2_Scott Timber	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
US2_Whitehouse	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
US2_Woodland	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
US3_Colonial Trail W	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
US3_Spring Grove	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
US4_Sadler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Dry Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2 PPA_Cox Bat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2 PPA_Sinai Bat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE1_PPA_Cavalier	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CE2_Dulles_50MW_tied	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(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
Walnut Solar	VA	Intermittent	Solar	2026	83	150
Winterpock Solar	VA	Intermittent	Solar	2025	11	20
Dulles Tied Solar	VA	Intermittent	Solar	2026	5	100
Sweet Sue Solar	VA	Intermittent	Solar	2026	4	75
Bridleton Solar	VA	Intermittent	Solar	2025	1	20
Cerulean Solar	VA	Intermittent	Solar	2026	3	62
Courthouse Solar	VA	Intermittent	Solar	2026	9	167
Ivy Landfill Distributed	VA	Intermittent	Solar	2025	0	3
Racefield Distributed	VA	Intermittent	Solar	2025	0	3
Kings Creek Solar	VA	Intermittent	Solar	2025	1	20
Southern VA Solar	VA	Intermittent	Solar	2025	7	125
Moon Corner Solar	VA	Intermittent	Solar	2026	3	60
North Ridge Solar	VA	Intermittent	Solar	2025	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	2027	3	50
CVOW - Phase 1 (2587MW)	VA	Intermittent	Wind	2024	856	2,587
Shands Storage	VA	Peak	Grid	2026	7	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-5 Solar	VA	Intermittent	Solar	2027	4.1	77.2
CE-5 Solar	VA	Intermittent	Solar	2029	6.9	130.8
CE-5 Distributed Solar	VA	Intermittent	Solar	2026	0.1	3.0
CE-5 Distributed Solar	VA	Intermittent	Solar	2026	0.2	3.0
Storage	VA	Peak	Grid			
Combustion Turbines	VA	Peak	Gas	2030	773	960

(1) Estimated commercial operation date.

Appendix 3C-3: Renewable Resources (for VCEA with EPA)

Company Name: Virginia Electric and Power Company

Schedule 11

RENEWABLE RESOURCE GENERATION (GWh)

Resource Type[1]	Unit Name	State	C.O.D.[2]	Build / Purchase / Convert[3]	Life/ Duration[4]	Size MW[5]	2021 (ACTUAL)	2022 (ACTUAL)	2023 (ACTUAL)	2024 (PROJECTED)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Hydro																									
	Gaston Hydro	NC	1963	Build	N/A	220	276	219	224	328	327	327	327	328	327	327	327	328	327	327	327	328	327	327	327
	North Anna Hydro	VA	1987	Build	N/A	1	0	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Roanoke Rapids Hydro	NC	1955	Build	N/A	95	386	145	177	284	283	283	283	284	283	283	283	284	283	283	283	284	283	283	283
					Sub-total: NC	315	661	363	401	612	610	610	610	612	610	610	610	612	610	610	610	612	610	610	610
					Sub-total: VA	1	0	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
					Sub-total: Hydro	316	661	363	401	614	612	612	612	614	612	612	612	614	612	612	612	614	612	612	612
Solar																									
	Chesapeake PPA	VA	2024	Purchase	20	118	-	-	-	219	217	216	215	215	213	212	210	210	208	207	206	205	203	202	201
	Pleasant Hill PPA	VA	2023	Purchase	20	20	-	-	22	37	37	37	37	36	36	36	36	36	35	35	35	35	35	34	34
	Rivanna PPA	VA	2024	Purchase	20	13	-	-	-	5	23	23	23	23	23	23	22	22	22	22	22	22	22	22	21
	Watlington PPA	VA	2023	Purchase	20	20	-	-	27	37	37	37	37	36	36	36	36	36	35	35	35	35	35	34	34
	Wythe 2 PPA	VA	2024	Purchase	20	75	-	-	-	14	139	138	137	137	136	135	135	134	133	132	132	131	130	129	129
	Clean Energy 2 DER 2 PPA	VA	2025	Purchase	20	15	-	-	-	-	1	11	11	11	11	11	11	11	11	11	11	11	10	10	10
	Clean Energy 2 DER 3 PPA	VA	2025	Purchase	20	7	-	-	-	-	4	11	11	11	11	11	11	11	11	11	11	10	10	10	10
	Cox PPA	VA	2026	Purchase	20	16	-	-	-	-	-	30	30	29	29	29	29	29	29	28	28	28	28	28	28
	Sinai PPA	VA	2026	Purchase	20	10	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	17	17	17	17
	Stratford PPA	VA	2023	Purchase	20	15	-	-	25	28	28	27	27	27	27	27	27	27	26	26	26	26	26	26	26
	Clean Energy 3 DER 1 PPA	VA	2025	Purchase	20	3	-	-	-	-	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Clean Energy 3 DER 2 PPA	VA	2026	Purchase	20	12	-	-	-	-	-	17	17	17	16	16	16	16	16	16	16	16	16	16	15
	Water Strider PPA	VA	2021	Purchase	20	80	118	178	174	146	145	144	143	143	142	141	140	139	138	137	136	135	133	132	131
	Westmoreland PPA	VA	2021	Purchase	20	20	11	48	42	37	36	36	36	36	35	35	35	35	34	34	34	34	33	33	33
	Grassfield Solar	VA	2022	Build	35	20	-	-	41	37	37	37	36	36	36	36	36	36	35	35	35	35	34	34	34
	Norge Solar	VA	2023	Build	35	20	-	-	3	37	37	37	37	36	36	36	36	36	35	35	35	35	35	34	34
	Sycamore Solar	VA	2023	Build	35	42	-	-	64	78	77	77	76	76	76	75	75	75	74	74	73	73	72	72	71
	Black Bear Distributed	VA	2023	Build	35	2	-	-	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Springfield Distributed	VA	2024	Build	35	2	-	-	-	1	4	4	4	4	4	4	4	4	4	4	4	4	3	3	3
	Camellia Solar	VA	2024	Build	35	20	-	-	-	9	35	35	35	35	34	34	34	34	34	34	33	33	33	33	33
	Fountain Creek Solar	VA	2024	Build	35	80	-	-	-	13	148	147	147	146	145	144	144	143	142	141	141	140	139	138	138
	Otter Creek Solar	VA	2024	Build	35	60	-	-	-	54	111	110	110	110	109	108	107	107	106	106	105	105	104	103	102
	Piney Creek Base Solar	VA	2023	Build	35	80	-	-	-	149	148	147	146	146	145	144	143	143	142	141	140	140	139	138	137
	Quillwort Solar	VA	2024	Build	35	18	-	-	-	5	33	33	33	33	33	32	32	32	32	32	32	31	31	31	31
	Sebera Solar	VA	2024	Build	35	18	-	-	-	5	31	31	31	31	31	30	30	30	30	30	30	30	29	29	29
	Solidago Solar	VA	2023	Build	35	20	-	-	20	37	37	37	37	36	36	36	36	36	35	35	35	35	34	34	34
	Walnut Solar	VA	2026	Build	35	150	-	-	-	-	-	125	261	260	258	257	256	255	253	252	251	250	248	247	245
	Winterberry Solar	VA	2023	Build	35	20	-	-	2	37	37	37	37	36	36	36	36	36	35	35	35	35	34	34	34
	Winterpock Solar	VA	2025	Build	35	20	-	-	-	-	18	37	37	37	36	36	36	36	36	35	35	35	35	34	34
	Scott Solar	VA	2016	Build	35	17	30	31	27	32	32	31	31	31	31	31	31	31	30	30	30	30	30	30	29
	Whitehouse Solar	VA	2016	Build	35	20	38	31	33	37	36	36	36	36	36	36	35	35	35	35	35	35	34	34	34
	Woodland Solar	VA	2016	Build	35	19	37	28	30	35	35	35	35	34	34	34	34	34	34	33	33	33	33	33	33
	Colonial Trail West	VA	2019	Build	35	140	276	275	259	260	258	257	255	255	253	252	250	250	248	247	245	245	243	242	240
	Spring Grove	VA	2020	Build	35	98	203	178	144	180	178	178	176	176	175	174	173	173	171	171	170	169	168	167	166
	Sadler Solar	VA	2021	Build	35	100	161	187	185	183	182	181	180	179	178	177	176	175	174	173	171	170	169	168	166
	Cavalier PPA	VA	2024	Purchase	20	155	-	-	-	170	287	286	284	284	281	280	278	278	275	274	272	272	269	268	266
	360 PPA	VA	2025	Purchase	20	52	-	-	-	-	17	96	96	96	95	94	94	93	93	92	92	91	91	90	90
	Surry PPA	VA	2025	Purchase	20	20	-	-	-	-	37	37	37	37	36	36	36	36	36	35	35	35	35	34	34
	Augusta PPA	VA	2026	Purchase	20	105	-	-	-	-	-	49	189	188	187	186	185	184	183	182	181	180	179	178	177
	Groves PPA	VA	2025	Purchase	20	16	-	-	-	-	14	29	28	28	28	28	28	28	28	27	27	27	27	27	27
	Jarratt PPA	VA	2027	Purchase	20	48	-	-	-	-	-	-	4	90	89	89	88	88	87	87	87	86	86	85	85
	Switchgrass PPA	VA	2025	Purchase	20	69	-	-	-	-	13	128	127	127	126	125	125	124	123	123	122	122	121	120	119
	Dulles Tied Solar	VA	2026	Build	35	100	-	-	-	-	-	41	172	172	171	170	169	168	167	166	165	165	164	163	162
	Sweet Sue Solar	VA	2026	Build	35	75	-	-	-	-	-	112	138	138	137	136	135	135	134	133	132	132	131	130	129
	Bridleton Solar	VA	2025	Build	35	20	-	-	-	-	17	35	35	35	35	35	34	34	34	34	34	34	33	33	33
	Cerulean Solar	VA	2026	Build	35	62	-	-	-	-	-	93	114	114	113	113	112	112	111	110	110	109	108	108	107
	Courthouse Solar	VA	2026	Build	35	167	-	-	-	-	-	105	298	298	295	294	292	292	289	288	286	286	283	282	280
	Ivy Landfill Distributed	VA	2025	Build	35	3	-	-	-	-	3	6	6	6	5	5	5	5	5	5	5	5	5	5	5
	Racefield Distributed	VA	2025	Build	35	3	-	-	-	-	1	6	6	6	5	5	5	5	5	5	5	5	5	5	5
	Kings Creek Solar	VA	2025	Build	35	20	-	-	-	-	1	36	36	36	35	35	35	35	35	35	34	34	34	34	34
	Southern VA Solar	VA	2025	Build	35	125	-	-	-	-	21	218	217	216	215	214	213	212	211	209	208	208	206	205	204
	Moon Corner Solar	VA	2026	Build	35	60	-	-	-	-	-	90	111	110	110	109	109	108	107	107	106	106	105	104	104
	North Ridge Solar	VA	2025	Build	35	20	-	-	-	-	22	37	37	37	36	36	36	36	36	35	35	35	35	35	34
	Clean Energy 4 DER Fixed T	VA	2027	Build	20	3	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5
	Clean Energy 4 DER Tracker	VA	2027	Build	20	3	-	-	-	-	-	-	17	17	17	16	16	16	16	16	16	16	16	16	16
	Flowers Solar PPA	VA	2027	Build	20	20	-	-	-	-	-	-	37	37	37	37	36	36	36	36	36	35	35	35	35
	Highlands CF Ft 23 Solar PP	VA	2027	Build	20	10	-	-	-	-	-	-	19	19	18	18	18	18	18	18	18	18	18	18	17
	Jessie DuPont Memorial Higl	VA	2027	Build	20	4	-	-	-	-	-	-	8	8	8	8	7	7	7	7	7	7	7	7	7
	Optimist Solar PPA	VA	2027	Build	20	36	-	-	-	-	-	-	67	67	66	66	66	66	65	65	64	64	64	63	63
	Richmond Highway Solar PP	VA	2027	Build	20	5	-	-	-	-	-	-	9	9	9	9	9	9	9	9	9	9	9	9	9
	Sycamore Cross Solar PPA	VA	2027	Build	20	240	-	-	-	-	-	-	445	443	440	438	436	434	431	429	427	425	422	420	418
	Windsor Solar PPA	VA	2027	Build	20	85	-	-	-	-	-	-	157	157	156	155	154	154	153	152	151	150	150	149	148
	Winfield Solar PPA	VA	2027	Build	20	20	-	-	-	-	-	-	37	37	37	36	36	36	36	36	35	35	35	35	35
	Beldale Solar	VA	2027	Build	35	57	-	-	-	-	-	-	106	105	105	104	103	103	102	102	101	101	100	100	99
	Blue Ridge Solar	VA	2027	Build	35	95	-	-	-	-	-	-	176	175	174	173	172	172	171	170	169	168	167	166	165
	Bookers Mill Solar	VA	2025	Build	35	127	-	-	-	-	220	219	218	217	215	214	213	213	211	210	209	208	207	205	204
	Michaux Solar	VA	2027	Build	35	50	-	-	-	-	-	-	93	92	92	91	91	90	90	89	89	89	88	88	87
	Clover Creek Solar	VA	2027	Build	35	90	-	-	-	-	-	-	143	142	142	141	140	140	139	138	137	137	136	135	134
	DER Alberta Solar	VA	2026	Build	35	3	-	-	-	-	-	6	6	6	5	5	5	5	5	5	5	5	5	5	5
	DER Carysbrook Solar	VA	2027	Build	35	3	-	-	-	-	-	-	6	6	6	5	5	5	5	5	5	5	5	5	5
	Hopewell Solar	VA	2029	Build	35	130	-	-	-	-	-	-	-	-	242	241	240	240	237	236	235	235	233	231	230
	Kiddsville Road DER PPA	VA	2027	Purchase	20	3	-	-	-	-	-	-	5	5	5	5	5	5	4	4	4	4	4	4	4
	Kings Hwy North DER PPA	VA	2028	Purchase	20	3	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5
	Kings Hwy South DER PPA	VA	2028	Purchase	20	2	-	-	-	-	-	-	-	4	4	4	4	4	4	4	4	4	4	4	4

Appendix 3C-3: Renewable Resources (for VCEA with EPA)

Company Name: Virginia Electric and Power Company

Schedule 11

RENEWABLE RESOURCE GENERATION (GWh)

Resource Type[1]	Unit Name	State	C.O.D.[2]	Build / Purchase / Convert[3]	Life/ Duration[4]	Size MW[5]	2021 (ACTUAL)	2022 (ACTUAL)	2023 (ACTUAL)	2024	2025	2026	2027	2028	2029	2030 (PROJECTED)	2031	2032	2033	2034	2035	2036	2037	2038	2039
	PEVA15 DER PPA	VA	2027	Purchase	20	2	-	-	-	-	-	-	4	4	4	3	3	3	3	3	3	3	3	3	3
	USS Staunton DER PPA	VA	2028	Purchase	20	3	-	-	-	-	-	-	-	6	5	5	5	5	5	5	5	5	5	5	5
	VAL025a DER PPA	VA	2028	Purchase	20	1	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2
	VAL025b DER PPA	VA	2028	Purchase	20	1	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2
	VAL032a DER PPA	VA	2027	Purchase	20	1	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2
	VAL035 DER PPA	VA	2027	Purchase	20	3	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5
	Whitby DER PPA	VA	2027	Purchase	20	2	-	-	-	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3
	Balwanz PPA	VA	2027	Purchase	20	18	-	-	-	-	-	-	32	32	32	32	31	31	31	31	31	31	30	30	30
	Blue Rock PPA	VA	2027	Purchase	20	100	-	-	-	-	-	-	185	184	183	183	182	181	180	179	178	177	176	175	174
	Caledon PPA	VA	2028	Purchase	20	22	-	-	-	-	-	-	-	41	41	40	40	40	40	40	39	39	39	39	39
	Carver PPA	VA	2028	Purchase	20	91	-	-	-	-	-	-	-	169	168	167	166	165	164	164	163	162	161	160	159
	Doyle Lake PPA	VA	2027	Purchase	20	9	-	-	-	-	-	-	16	16	16	15	15	15	15	15	15	15	15	15	15
	Ho Fel PPA	VA	2027	Purchase	20	40	-	-	-	-	-	-	74	74	73	73	73	73	72	72	71	71	70	70	70
	Poth PPA	VA	2028	Purchase	20	20	-	-	-	-	-	-	-	37	37	37	37	36	36	36	36	36	35	35	35
	Potts PPA	VA	2027	Purchase	20	20	-	-	-	-	-	-	37	37	37	37	36	36	36	36	36	35	35	35	35
	Prairie PPA	VA	2025	Purchase	20	20	-	-	-	-	37	37	37	37	36	36	36	36	36	35	35	35	35	35	34
	Springfield PPA	VA	2028	Purchase	20	80	-	-	-	-	-	-	-	142	141	140	140	139	138	138	137	136	136	135	134
	Waller PPA	VA	2028	Purchase	20	131	-	-	-	-	-	-	-	244	242	240	239	239	237	235	234	234	232	231	229
	White PPA	VA	2027	Purchase	15	20	-	-	-	-	-	-	37	37	37	37	36	36	36	36	36	36	35	35	35
	Woodridge PPA	VA	2028	Purchase	20	138	-	-	-	-	-	-	-	256	254	253	252	251	249	248	247	246	244	243	242
	Solar_DG Hybrid - (3MW)	VA	2030	Build	35	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	189	377	569	767	957
	Solar_DG Hybrid - (3MW) 20	VA	2029	Build	35	3	-	-	-	-	-	-	-	-	83	83	83	82	82	81	81	80	80	80	79
	Solar_DG Hybrid - (3MW) 20	VA	2030	Build	35	3	-	-	-	-	-	-	-	-	-	122	122	121	120	120	119	119	118	117	116
	Solar_DG Hybrid - (3MW) 20	VA	2031	Build	35	3	-	-	-	-	-	-	-	-	-	-	139	138	138	137	136	136	135	134	133
	Solar_DG Hybrid - (3MW) 20	VA	2032	Build	35	3	-	-	-	-	-	-	-	-	-	-	-	161	160	160	159	158	157	156	155
	Solar_DG Hybrid - (3MW) 20	VA	2033	Build	35	3	-	-	-	-	-	-	-	-	-	-	-	-	178	177	176	175	174	173	172
	Solar_DG Hybrid - (3MW) 20	VA	2034	Build	35	3	-	-	-	-	-	-	-	-	-	-	-	-	-	183	182	182	181	180	179
	Solar_PPA	VA	2035	Purchase	20	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	556	1,109	1,659	2,206	2,570
	Solar_PPA 2029	VA	2029	Purchase	20	60	-	-	-	-	-	-	-	-	667	663	609	655	651	408	641	642	639	627	211
	Solar_PPA 2030	VA	2030	Purchase	20	60	-	-	-	-	-	-	-	-	-	667	661	658	657	531	647	646	643	636	263
	Solar_PPA 2031	VA	2031	Purchase	20	60	-	-	-	-	-	-	-	-	-	-	554	551	550	517	542	541	539	534	267
	Solar_PPA 2032	VA	2032	Purchase	20	60	-	-	-	-	-	-	-	-	-	-	-	554	553	545	547	544	542	538	368
	Solar_PPA 2033	VA	2033	Purchase	20	60	-	-	-	-	-	-	-	-	-	-	-	-	556	551	550	547	544	541	462
	Solar_PPA 2034	VA	2034	Purchase	20	60	-	-	-	-	-	-	-	-	-	-	-	-	-	556	553	550	547	544	483
	Solar_Tracker (60MW)	VA	2029	Build	35	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Generic Solar PV Hybrid- (60	VA	2035	Build	35	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,333	2,662	3,980	5,294	6,601
	Generic Solar PV Hybrid- (60	VA	2028	Build	35	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Generic Solar PV Hybrid- (60	VA	2029	Build	35	60	-	-	-	-	-	-	-	-	1,222	1,216	1,210	1,205	1,198	1,192	1,186	1,180	1,173	1,167	1,161
	Generic Solar PV Hybrid- (60	VA	2030	Build	35	60	-	-	-	-	-	-	-	-	-	1,222	1,216	1,211	1,204	1,198	1,192	1,186	1,179	1,173	1,167
	Generic Solar PV Hybrid- (60	VA	2031	Build	35	60	-	-	-	-	-	-	-	-	-	-	1,333	1,328	1,320	1,313	1,307	1,301	1,293	1,287	1,280
	Generic Solar PV Hybrid- (60	VA	2032	Build	35	60	-	-	-	-	-	-	-	-	-	-	-	1,334	1,327	1,320	1,313	1,307	1,300	1,293	1,287
	Generic Solar PV Hybrid- (60	VA	2033	Build	35	60	-	-	-	-	-	-	-	-	-	-	-	-	1,333	1,327	1,320	1,314	1,307	1,300	1,293
	Generic Solar PV Hybrid- (60	VA	2034	Build	35	60	-	-	-	-	-	-	-	-	-	-	-	-	-	1,333	1,327	1,321	1,313	1,307	1,300
					Sub-total: NC	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					Sub-total: VA	5,202	129	227	1,099	1,884	2,836	4,026	6,409	7,379	9,541	11,503	13,417	15,464	17,437	19,020	21,386	23,383	25,325	27,265	27,676
					Sub-total: Solar	5,202	129	227	1,099	1,884	2,836	4,026	6,409	7,379	9,541	11,503	13,417	15,464	17,437	19,020	21,386	23,383	25,325	27,265	27,676
Wind	CVOW (Demonstration)	VA	2021	Build	30	11	50	51	47	41	40	40	40	41	40	40	40	41	40	40	40	41	40	40	40
	CVOW - Phase 1 (2587MW)	VA	2024	Build	33	2587	-	-	-	-	-	-	9,523	9,567	9,523	9,523	9,523	9,567	9,523	9,523	9,523	9,567	9,523	9,523	9,523
	Generic Wind- (60MW)	VA	2028	Build	25	60	-	-	-	-	-	-	-	-	-	-	197	198	197	197	197	198	197	197	197
	New Wind 800MW	VA	2032	Build	30	800	-	-	-	-	-	-	-	-	-	-	-	-	-	2,945	2,945	2,958	2,945	2,945	2,945
	CVOW - Phase 2 (2600 MW)	VA	2033	Build	30	2600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,571
					Sub-total: NC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
					Sub-total: VA	6,058	50	51	47	41	40	40	9,563	9,607	9,563	9,563	9,760	9,805	9,760	12,705	12,705	12,764	12,705	12,705	22,276
					Sub-total: Wind	6,058	50	51	47	41	40	40	9,563	9,607	9,563	9,563	9,760	9,805	9,760	12,705	12,705	12,764	12,705	12,705	22,276
					Total Renewables: NC	315	661	363	401	612	610	610	610	612	610	610	610	612	610	610	610	612	610	610	610
					Total Renewables: VA	11,261	179	278	1,146	1,927	2,878	4,069	15,975	16,988	19,106	21,069	23,180	25,272	27,200	31,727	34,094	36,150	38,032	39,973	49,954
					Total Renewables	11,576	840	641	1,547	2,539	3,488	4,679	16,584	17,600	19,716	21,679	23,790	25,883	27,810	32,337	34,704	36,761	38,642	40,582	50,563

(1) Per definition in Va. Code § 56-576.
(2) Commercial operation date.
(3) Company built, purchased, or converted.
(4) Expected life of facility or duration of purchase contract.
(5) Net Summer Capacity for hydro, nameplate for solar and wind.

Appendix 3C-4: Potential Supply-Side Resources for VCEA with EPA

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

UNIT PERFORMANCE DATA

Potential Supply-Side Resources (MW)

Unit Name	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Annual Firm	MW Nameplate
Solar 2029	Intermittent	Solar	2029	24	458
Battery 2029	Storage		2029	47	65
Solar 2030	Intermittent	Solar	2030	25	472
Battery 2030	Storage		2030	47	65
Generic CT	Peak	Natural Gas	2030	794	970
Solar 2031	Intermittent	Solar	2031	27	517
Battery 2031	Storage		2031	71	98
Onshore Wind	Intermittent	Wind	2031	12	60
Generic CT	Peak	Natural Gas	2031	670	818
Solar 2032	Intermittent	Solar	2032	28	525
Battery 2032	Storage		2032	95	130
Generic CT	Peak	Natural Gas	2032	670	818
Solar 2033	Intermittent	Solar	2033	28	530
Battery 2033	Storage		2033	95	130
Generic CT	Peak	Natural Gas	2033	670	818
Solar 2034	Intermittent	Solar	2034	28	532
Battery 2034	Storage		2034	95	130
Offshore Wind	Intermittent	Wind	2034	265	800
Generic CC	Intermittent	Natural Gas	2034	1,043	1,268
Solar 2035	Intermittent	Solar	2035	28	534
Battery 2035	Storage		2035	95	130
Generic CC	Intermittent	Natural Gas	2035	1,038	1,268
Nuclear	Baseload	Uranium	2035	252	268
Solar 2036	Intermittent	Solar	2036	28	534
Battery 2036	Storage		2036	119	163
Nuclear	Baseload	Uranium	2036	252	268
Solar 2037	Intermittent	Solar	2037	28	536
Battery 2037	Storage		2037	119	163
Nuclear	Baseload	Uranium	2037	252	268
Solar 2038	Intermittent	Solar	2038	28	538
Battery 2038	Storage		2038	142	195
Nuclear	Baseload	Uranium	2038	252	268
Solar 2039	Intermittent	Solar	2039	28	536
Battery 2039	Storage		2039	142	195
Offshore Wind	Intermittent	Wind	2039	860	2,600
Nuclear	Baseload	Uranium	2039	252	268

(1) Estimated commercial operation date

Appendix 3C-5: Summer Capacity Position for VCEA with EPA

Company Name: Virginia Electric and Power Company **Schedule 16**

UTILITY CAPACITY POSITION (MW)

	(ACTUAL)								(PROJECTED)										
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Existing Capacity																			
Conventional	17,200	17,195	15,392	15,110	15,110	12,569	12,641	12,748	12,923	12,912	13,106	13,133	12,928	12,673	12,673	12,673	12,673	12,673	12,673
Renewable NC	-	-	-	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315
Renewable VA	128	224	290	1,062	1,110	286	217	193	193	170	147	146	146	122	122	100	99	99	99
Renewable	128	224	290	1,377	1,425	601	532	508	508	485	462	461	461	437	437	415	414	414	414
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	1,809	1,809	1,827	1,835	1,835	1,271	1,216	1,270	1,215	1,233	1,141	1,140	1,139	1,138	1,137	1,136	1,135	1,134	1,133
Storage	1,809	1,809	1,827	1,835	1,835	1,271	1,216	1,270	1,215	1,233	1,141	1,140	1,139	1,138	1,137	1,136	1,135	1,134	1,133
Total Existing Capacity	19,137	19,228	17,510	18,323	18,370	14,440	14,389	14,527	14,647	14,630	14,709	14,734	14,528	14,248	14,247	14,224	14,223	14,222	14,221
Generation Under Construction																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	-	-	-	113	102	1,605	1,356	1,278	1,103	1,057	954	798	597	597	577	577	577	577
Renewable	-	-	-	-	113	102	1,605	1,356	1,278	1,103	1,057	954	798	597	597	577	577	577	577
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	22	24	22	23	21	20	17	17	15	14	14	13	12	12	11
Storage	-	-	-	-	22	24	22	23	21	20	17	17	15	14	14	13	12	12	11
Total Planned Construction Capacity	-	-	-	-	135	126	1,627	1,379	1,299	1,123	1,074	970	814	612	611	591	590	589	589
Generation Under Development																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage NC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Development Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Potential (Expected) New Capacity																			
Conventional	-	-	-	-	2,352	-	-	-	-	765	774	1,861	2,528	3,181	4,087	5,354	5,581	5,808	6,034
Renewable NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA		-	-	-	10	2	26	55	139	184	221	275	330	469	514	462	496	530	1,084
Renewable	-	-	-	-	10	2	26	55	139	184	221	275	330	469	514	462	496	530	1,084
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	84	126	345	498	650	704	851	951	1,036	1,138	1,234	1,284	1,362	1,433
Storage	-	-	-	-	-	84	126	345	498	650	704	851	951	1,036	1,138	1,234	1,284	1,362	1,433
Total Potential New Capacity	-	-	-	-	2,362	86	151	400	637	1,599	1,700	2,988	3,808	4,687	5,740	7,050	7,361	7,699	8,551
Other (PPA)																			
Conventional	-	-	-	142	142	142	121	121	14	14	14	14	14	14	14	14	14	14	14
Renewable NC	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable VA	-	64	84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	-	64	84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage VA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other (PPA) Capacity	-	64	84	142	142	142	121	121	14	14	14	14	14	14	14	14	14	14	14
Unforced Availability	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Generation Capacity	19,137	19,293	17,594	18,465	21,009	14,795	16,288	16,426	16,597	17,366	17,497	18,706	19,164	19,561	20,612	21,878	22,187	22,524	23,374
Existing DSM Reductions																			
Demand Response	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conservation/Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing DSM Reductions[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Approved DSM Reductions																			
Demand Response	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conservation/Efficiency[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Approved DSM Reductions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Proposed DSM Reductions																			
Demand Response	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 3C-5: Summer Capacity Position for VCEA with EPA

Company Name: Virginia Electric and Power Company

Schedule 16

UTILITY CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)															
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Conservation/Efficiency[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Proposed DSM Reductions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency & Demand Response[1]	331	186	204	92	186	266	346	402	437	461	496	526	551	581	627	654	701	781	916
Customer Choice[1]	-	-	-	601	601	601	601	601	601	601	601	601	601	601	601	601	601	601	601
Net Generation & Demand-side	19,467	19,479	17,798	18,465	21,009	14,795	16,288	16,426	16,597	17,366	17,497	18,706	19,164	19,561	20,612	21,878	22,187	22,524	23,374
Capacity Sale[3]	-	9	-	-	198	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Purchase[3]	468	-	2,949	3,335	-	3,170	2,256	2,760	2,726	2,421	2,783	2,168	2,340	2,684	2,462	2,107	2,662	3,184	3,249
Capacity Adjustment[3]	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Requirement or PJM Capacity Obligation	19,935	19,470	20,747	21,800	20,811	17,964	18,545	19,187	19,323	19,787	20,280	20,875	21,504	22,245	23,074	23,985	24,849	25,708	26,623
Net Utility Capacity Position	-	-	-	(3,335)	198	(3,170)	(2,256)	(2,760)	(2,726)	(2,421)	(2,783)	(2,168)	(2,340)	(2,684)	(2,462)	(2,107)	(2,662)	(3,184)	(3,249)

(1) Values accounted for in the load forecast.

(2) Efficiency programs are not part of the Company's calculation of capacity.

(3) Capacity sale, purchase, and adjustments are used for modeling purposes.

Appendix 3C-6: Capacity Position for VCEA with EPA

Company Name: Virginia Electric and Power Company

Schedule 4

POWER SUPPLY DATA

	(ACTUAL)								(PROJECTED)										
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
I. Capability (MW)																			
1. Summer																			
a. Firm Capacity Capacity(1)	19,137	19,228	17,510	18,323	20,867	14,653	16,167	16,305	16,583	17,351	17,483	18,692	19,150	19,547	20,598	21,864	22,173	22,510	23,360
b. Positive Interchange Commitments(2)	-	64	84	142	142	142	121	121	14	14	14	14	14	14	14	14	14	14	14
c. Capacity Sale(3)	-	9	-	-	198	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Capacity Purchase(3)	468	-	2,949	3,335	-	3,170	2,256	2,760	2,726	2,421	2,783	2,168	2,340	2,684	2,462	2,107	2,662	3,184	3,249
e. Capacity Adjustment(3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
f. Total Net Summer Capability(4)	19,604	19,301	20,543	21,800	21,207	17,964	18,545	19,187	19,323	19,787	20,280	20,875	21,504	22,245	23,074	23,985	24,849	25,708	26,623
2. Winter																			
a. Firm Capacity Capacity(1)	19,137	19,228	17,510	18,518	21,760	18,342	20,377	20,610	20,777	21,902	21,979	23,448	24,459	26,066	27,350	29,035	29,366	29,725	32,061
b. Positive Interchange Commitments(2)	-	64	84	142	142	142	121	121	14	14	14	14	14	14	14	14	14	14	14
e. Total Net Winter Capability(4)	19,137	19,293	17,594	18,661	21,902	18,484	20,498	20,731	20,791	21,917	21,993	23,462	24,473	26,080	27,364	29,049	29,381	29,739	32,075

(1) Net seasonal capability.

(2) Does not include firm commitments from existing purchase power agreements and estimated solar PPAs.

(3) Capacity sale, purchase, and adjustments are used for modeling purposes.

(4) Does not include behind-the-meter generation MW.

*Demand response programs are not classified as capacity resources and are included in adjusted load (Appendix 2B-8)

Appendix 3C-7: Construction Forecast

Company Name: Virginia Electric and Power Company **Schedule 17**

CONSTRUCTION COST FORECAST (Thousand Dollars)

(PROJECTED)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
I. New Traditional Generating Facilities																
a. Construction Expenditures (non-AFUDC)	-	130,269	334,314	646,069	796,256	1,171,310	1,561,287	2,112,010	2,612,245	2,878,015	2,647,800	2,073,144	1,415,310	760,684	310,384	4,672
b. AFUDC	-	232	1,120	3,402	7,402	13,613	21,886	26,093	29,231	40,214	42,419	50,823	44,851	36,301	25,536	13,173
c. Annual Total	-	130,500	335,434	649,471	803,658	1,184,923	1,583,173	2,138,103	2,641,475	2,918,229	2,690,219	2,123,968	1,460,161	796,984	335,920	17,845
d. Cumulative Total	-	130,500	465,934	1,115,406	1,919,064	3,103,986	4,687,160	6,825,263	9,466,738	12,384,968	15,075,187	17,199,154	18,659,315	19,456,300	19,792,219	19,810,064
II. New Renewable Generating Facilities																
a. Construction Expenditures (non-AFUDC)	-	125,359	223,805	594,619	1,546,251	1,180,484	1,313,773	1,370,545	1,332,396	1,469,230	2,286,231	2,847,537	4,220,188	4,943,775	3,767,975	355,784
b. AFUDC	-	223	1,143	2,951	6,897	12,103	13,908	17,864	22,090	26,639	30,670	19,133	27,393	39,501	50,767	52,895
c. Annual Total	-	125,582	224,947	597,570	1,553,147	1,192,587	1,327,681	1,388,410	1,354,486	1,495,870	2,316,901	2,866,669	4,247,580	4,983,276	3,818,742	408,679
d. Cumulative Total	-	125,582	350,530	948,100	2,501,247	3,693,834	5,021,515	6,409,924	7,764,410	9,260,280	11,577,181	14,443,850	18,691,431	23,674,707	27,493,449	27,902,128
III. New Storage Facilities																
a. Construction Expenditures (non-AFUDC)	-	-	22,918	40,894	115,484	212,291	250,335	318,830	358,323	371,385	382,135	426,978	476,408	441,094	426,245	234,176
b. AFUDC	-	-	41	154	433	1,016	1,187	1,558	1,816	1,845	1,910	2,068	2,388	2,404	2,324	1,545
c. Annual Total	-	-	22,958	41,049	115,917	213,307	251,522	320,388	360,138	373,230	384,045	429,045	478,795	443,498	428,569	235,721
d. Cumulative Total	-	-	22,958	64,007	179,924	393,231	644,753	965,141	1,325,280	1,698,510	2,082,555	2,511,600	2,990,395	3,433,893	3,862,462	4,098,183
IV. Other Facilities																
a. Transmission	1,929,229	2,029,740	2,287,993	2,274,943	2,328,066	2,339,581	2,361,482	2,374,271	2,374,271	1,860,000	1,860,000	1,860,000	1,860,000	1,860,000	1,860,000	1,860,000
b. Distribution	1,831,795	1,697,204	1,757,116	1,732,799	1,677,989	1,704,211	1,346,223	1,351,874	1,365,545	1,365,545	1,365,545	1,365,545	1,365,545	1,365,545	1,365,545	1,365,545
c. Energy Conservation & DR																
d. Other																
e. AFUDC	122,769	169,857	163,332	174,035	118,461	104,385	79,808	67,019	67,019	140,000	140,000	140,000	140,000	140,000	140,000	140,000
f. Annual Total	3,883,792	3,896,801	4,208,441	4,181,777	4,124,516	4,148,177	3,787,512	3,793,163	3,806,834	3,365,545	3,365,545	3,365,545	3,365,545	3,365,545	3,365,545	3,365,545
g. Cumulative Total	3,883,792	7,780,593	11,989,034	16,170,811	20,295,327	24,443,504	28,231,017	32,024,180	35,831,015	39,196,560	42,562,105	45,927,650	49,293,195	52,658,740	56,024,285	59,389,830
V. Total Construction Expenditures																
a. Annual	3,883,792	4,152,884	4,791,780	5,469,867	6,597,239	6,738,993	6,949,889	7,640,065	8,162,934	8,152,874	8,756,710	8,785,227	9,552,082	9,589,303	7,948,776	4,027,789
b. Cumulative	3,883,792	8,036,676	12,828,456	18,298,324	24,895,562	31,634,556	38,584,445	46,224,509	54,387,443	62,540,317	71,297,027	80,082,255	89,634,336	99,223,639	107,172,415	111,200,204
VI. % of Funds for Total Construction Provided from External Financing	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

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, 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.

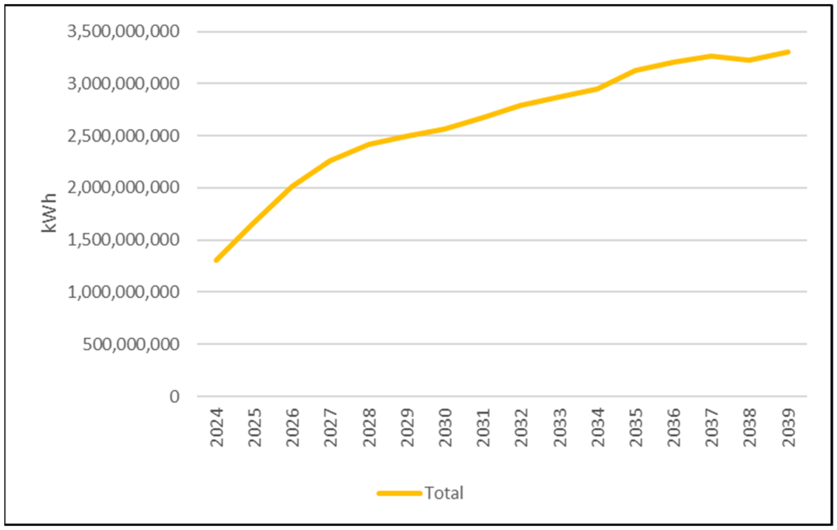
To develop the energy and capacity reductions used in the primary Portfolios, the Company used the energy efficiency savings targets proposed in Case No. PUR-2023-00227 for 2026-2028 and continued to increase the savings forecast throughout the remaining 15-year planning horizon. As discussed in that case, the 2026-2028 proposed targets were calculated as follows,

> *For customer-facing portfolio energy efficiency programs, the Company's proposal assumes a 10% annual increase in cumulative persistent savings, starting from the 2023 actual savings. This is consistent with the average annual increase observed from 2019 to 2023. The same 10% growth rate is applied to the IAQ programs. As to voltage optimization savings, the Company utilizes the most recent forecasted VO projections. Regarding LGS opt-out customers' savings, the Company uses the actual savings and projected savings based on historic opt-out incremental savings.*

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 July 26, 2024, of DSM Programs was in Case No. PUR-2023-00217. All new programs and measures approved therein will be available to customers at the beginning of 2025 and have been included in the forecasted savings in this 2024 IRP. Any future DSM programs or measures capable of delivering incremental savings would not be available until 2026 at the earliest, pending regulatory approval.

The Company's 2024 IRP DSM adjustment is ambitious, with forecasted energy savings growing from 1,306 GWh in 2024 to 2,500 GWh by 2029, and well over 3,000 GWh by 2039.

Figure 1

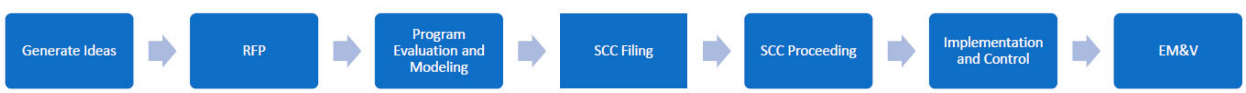


All savings are calculated on a net basis, meaning savings from "free riders"—customers that participate and receive an incentive through a utility-sponsored DSM program but who would have taken the action to achieve savings even absent the incentive—are removed from the calculation. Said another way, 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 2023 include:

Figure 2

~371,000
participants reached*

$18 million
in bill savings for customers

92 million
gallons/year of water savings

524,000
metric tons of CO_2 avoided

1,404 GWh
gross energy savings toward Virginia Clean Economy Act (VCEA)

II. Active DSM Programs and Incremental Savings

Appendix 6A 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. Appendices 6B, 6C, 6D, and 6E provide the system-level non-coincidental peak savings, coincidental summer peak savings, annual energy savings, and penetrations for each active program.

In addition to the active DSM programs, on December 11, 2023, the Company filed for SCC approval in Case No. PUR-2023-00217 for four new DSM programs:

- Residential New Construction (EE)
- Residential Smart Thermostat Purchase (EE)
- Residential Smart Thermostat (DR)
- Non-residential New Construction (EE)

The SCC issued its Final Order in Case No. PUR-2023-00217 on July 26, 2024, approving all four programs.

Appendix 6F provides program descriptions for these recently approved DSM programs. Appendices 6G, 6H, 6I and 6J provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each program.

Because the Company's DSM adjustment also includes incremental savings beyond those that can be achieved by the currently active programs, Appendices 6K and 6L provide the system-level coincidental peak savings and energy savings for the generic undesignated EE programs necessary to achieve the forecasted growth.

III. Rejected DSM Programs

A list of the rejected DSM programs from prior integrated resource planning cycles is shown in Appendix 6M. 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.

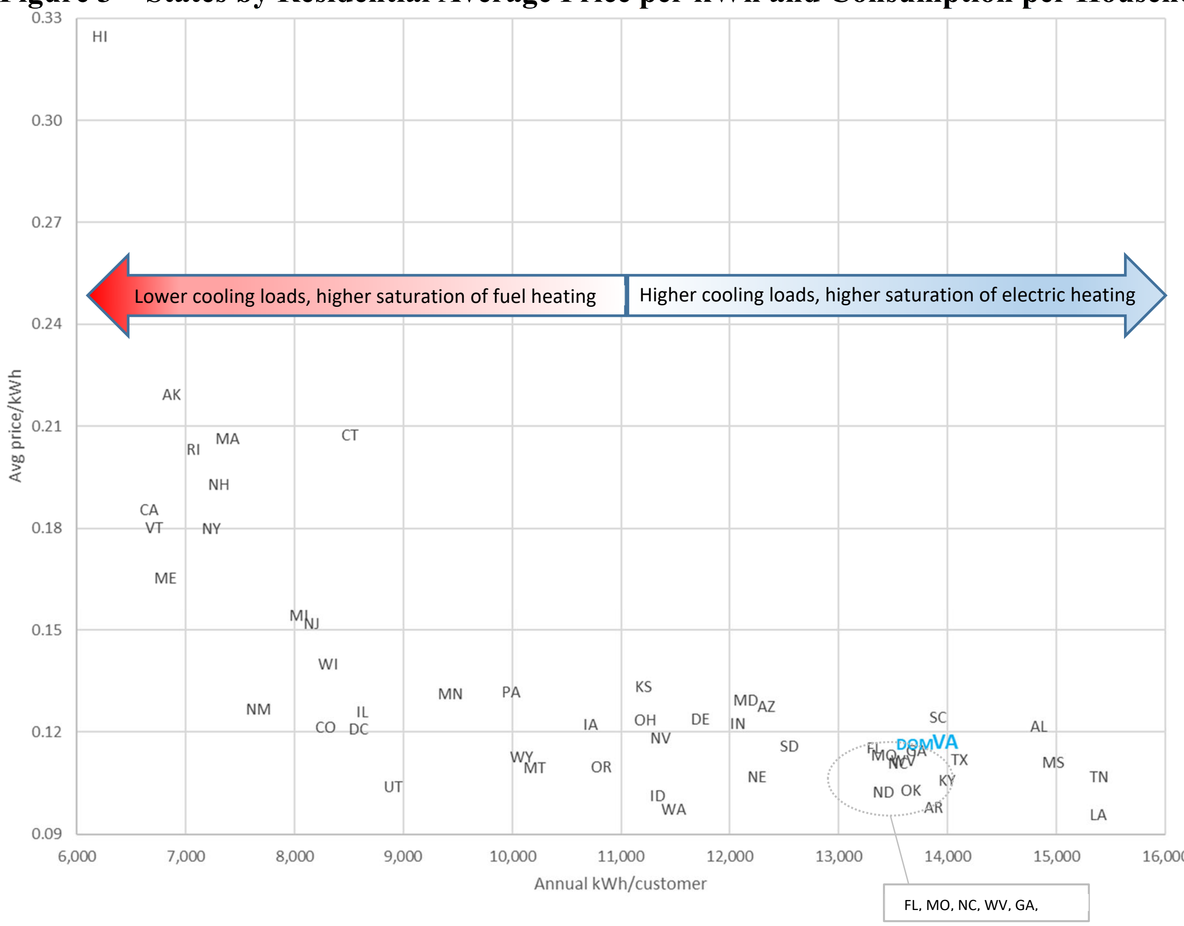
Separate from program proposals, a special subgroup focused on low-income DSM program improvements meets as part of the stakeholder process and making valued suggestions for future program improvements that will result in better alignment with the state's federally funded program. The Company has and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

Electricity Rate and Consumption Comparison

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



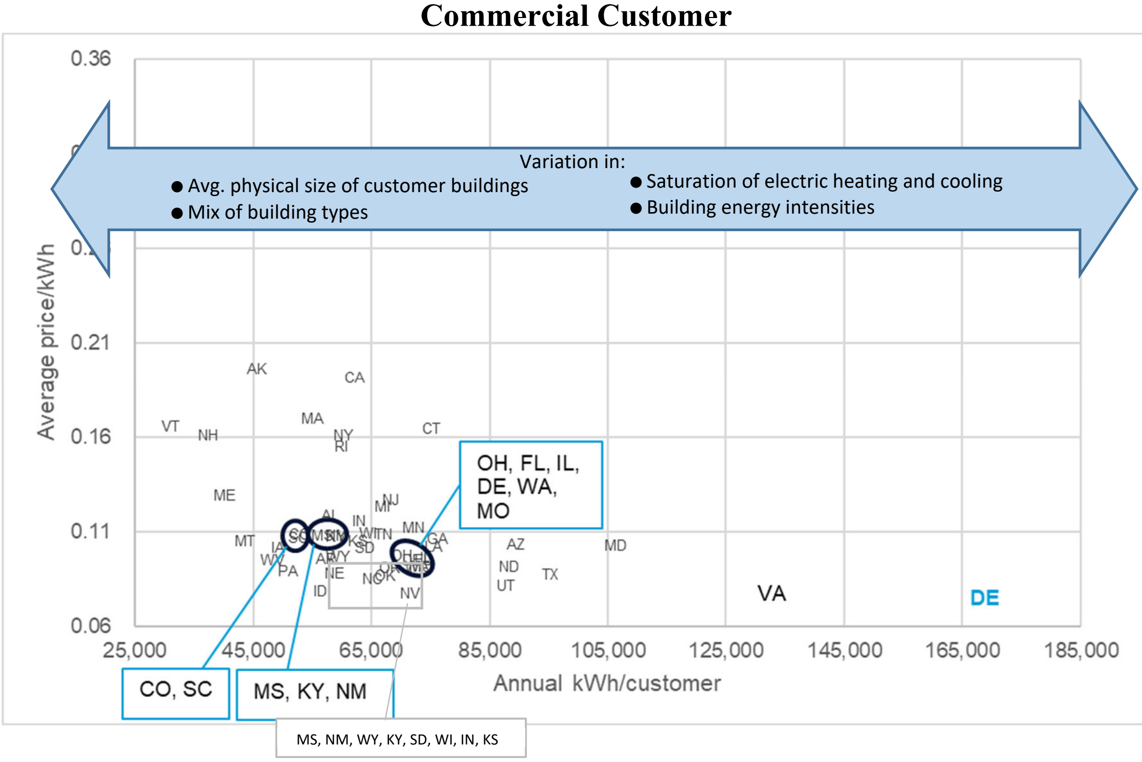
Notes: U.S. Energy Information Administration. Table 5A, Residential Average Monthly Bill by Census Division, and State (Annualized), https://www.eia.gov/electricity/sales_revenue_price/.

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.

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:	2022– 2045

Program Description:
All residential customers 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 active 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:	2022– 2045

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 active 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 approved 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 active 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 active 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 recently approved 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 active 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:	2022– 2045

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 active 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:	2023-2045

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 recently approved 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 active 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 active DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Residential New Construction 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 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.

Program Marketing:
The Company uses a number of marketing activities to promote its active 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 active 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 active 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:	2021 – 2045
NC Duration:	2022– 2045

Program Description:
This Program provides qualifying facility owners with incentives to install energy efficient measures in their new construction project.

Program Marketing:
The Company uses a number of marketing activities to promote its active 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:	2022– 2045

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 active 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 active 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 active 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:	2023-2045

Program Description:
Program is designed to give the Company's residential customers control over their water related energy use. The recently approved 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 active 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:	2023-2045

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 active 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 active 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:	2023-2045

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: 2023-2045

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: 2023-2045

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: 2023-2045

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 active 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 active 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 recently approved 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 active 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 active 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:	2023 – 2045

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 active 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 active 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 active 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, recently approved 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 active 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 active 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 recently approved program pilot would run in parallel with the current Residential Electric Vehicle Demand Response Program. Instead of communicating with the electric vehicle charger, the recently approved 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 active 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 active 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.

Appendix 3E-1: Active Programs Non-Coincidental Peak Savings
(kW) (System Level)

Phase	Acronym	Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
I	CHVC	Commercial HVAC Upgrade Program	2,674	2,673	1,774	226	0	0	0	0	0	0	0	0	0	0	0	0
I	CLGT	Commercial Lighting Program	216	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I	EALI	Low Income Program	2,654	1,912	1,012	689	259	75	0	0	0	0	0	0	0	0	0	0
II	CDUC	Commercial Duct Testing & Sealing Program	29,427	29,425	29,415	29,486	29,459	29,430	29,434	29,425	29,434	29,483	29,444	29,430	29,436	29,415	29,408	25,985
II	DG	Commercial Distributed Generation Program	6,945	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
II	EACI	Commercial Energy Audit Program	660	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
II	EAR1	Residential Home energy Check Up	9,077	5,060	2,700	257	0	0	0	0	0	0	0	0	0	0	0	0
II	RDUC	Residential Duct Testing & Sealing Program	408	408	408	408	408	408	408	405	373	303	66	9	0	0	0	0
II	RHEH	Heat Pump Upgrade Program	6,927	6,927	6,926	6,927	6,825	3,434	628	398	87	0	0	0	0	0	0	0
III	CHV2	Non-Residential Heating and Cooling Efficiency Program	19,803	19,803	19,809	19,881	19,871	19,816	19,534	17,389	14,806	9,438	2,385	0	0	0	0	0
III	CLT2	Non-Residential Lighting Systems & Controls Program	45,838	45,018	36,776	26,679	15,708	8,343	114	0	0	0	0	0	0	0	0	0
III	CSWF	Non-Residential Window Film	6,864	2,393	2,122	1,304	64	3	0	0	0	0	0	0	0	0	0	0
IV	EAL3	Income and Age Qualifying Home Improvement Program	2,690	2,786	2,785	2,785	2,689	2,786	2,437	1,376	732	732	595	194	104	0	0	0
IV	RARC	Residential Appliance Recycling Program	1,125	292	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V	RLED	Residential Retail LED Lighting Program (NC only)	1,649	1,649	1,649	1,648	1,648	1,649	1,649	1,649	1,649	1,648	1,649	1,649	1,649	1,536	1,111	0
V	SBIP	Small Business Improvement Program	14,619	14,629	14,628	14,695	14,683	14,628	14,629	14,059	10,109	5,786	2,626	476	0	0	0	0
VI	CNRP	Non-Residential Prescriptive Program	16,780	15,381	12,682	6,995	944	0	0	0	0	0	0	0	0	0	0	0
VII	CHV3	Non-Residential Heating and Cooling Efficiency Program	33,554	33,756	33,785	33,877	33,714	33,787	33,783	33,756	33,639	33,889	33,864	33,787	31,292	30,650	18,405	0
VII	CLT3	Non-Residential Lighting Systems & Controls Program	8,294	8,296	8,296	8,307	8,306	8,296	8,284	5,805	3,024	1,720	0	0	0	0	0	0
VII	CSW2	Non-Residential Window Film Program	224	224	224	224	224	224	217	115	88	26	0	0	0	0	0	0
VII	CTSM	Non-Residential Small Manufacturing Program	3,881	3,883	3,883	3,895	3,893	3,883	3,883	3,883	3,887	3,895	3,878	2,379	360	0	0	0
VII	CTSO	Non-Residential Office Program	18,152	18,142	18,115	18,136	16,065	15,783	6,803	0	0	0	0	0	0	0	0	0
VII	RAR2	Residential Appliance Recycling Program (v2)	450	450	450	450	277	242	185	75	0	0	0	0	0	0	0	0
VII	REE2	Residential Efficient Products Marketplace Program	222	224	224	224	222	224	224	224	222	224	224	224	222	224	224	224
VII	REEC	Residential Efficient Products Marketplace Program	70,818	70,813	70,811	70,796	70,796	70,816	70,815	70,813	70,805	70,796	70,803	70,816	66,695	46,763	30,859	12,140
VII	RTHO	Home Energy Assessment	5,775	5,774	5,774	5,772	5,772	5,774	5,774	5,774	5,769	5,507	4,092	1,836	252	0	0	0
VIII	CEEP	Non-Residential EE Products	2,209	5,996	7,574	7,574	7,574	7,574	7,574	7,574	7,574	7,574	7,574	7,574	7,574	7,574	7,574	7,574
VIII	CMFP	Non-Residential Multifamily Program	4,436	8,882	9,208	9,208	9,208	9,208	9,208	9,208	8,317	3,978	0	0	0	0	0	0
VIII	CNCR	Non-Residential New Construction	10,447	10,448	10,451	10,454	9,461	9,456	10,447	10,448	10,452	10,456	9,461	9,456	10,447	10,451	10,250	2,002
VIII	RCEB	Residential Customer Engagement Program	2,050	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	REVDR	Residential Electric Vehicle Peak Shaving (DR)	109	355	648	946	1,072	1,080	1,093	1,106	1,119	1,132	1,144	1,155	1,166	1,176	1,186	1,198
VIII	REVEE	Residential Electric Vehicle (EE)	68	167	217	217	217	217	217	217	217	217	179	101	0	0	0	0
VIII	RHR2	Residential Enhanced Home Retrofit	7,563	15,127	16,008	16,008	16,008	16,008	16,008	16,008	16,008	16,008	16,008	16,008	16,008	16,008	16,008	16,008
VIII	RHRF	Residential Home Retrofit	167	167	168	168	167	167	167	167	167	167	167	167	167	164	151	142
VIII	RHVC	Residential Low Income and Age Qualifying HVAC HB 2789	1,583	1,584	1,584	1,585	1,577	1,509	836	578	518	518	518	518	517	515	513	512
VIII	RKTS	Residential EE Kits	1,839	1,839	1,779	1,238	1,185	1,185	1,079	516	112	80	71	71	71	60	50	48
VIII	RMFP	Residential Multifamily Program	858	1,715	2,356	2,356	2,356	2,356	2,356	2,356	2,356	2,258	1,080	29	29	28	24	20
VIII	RMHP	Residential Manufactured Housing Program	103	279	352	352	352	352	270	129	3	3	1	1	1	0	0	0
VIII	RNCR	Residential New Construction	5,819	5,820	5,820	5,820	5,820	5,820	5,819	5,820	5,821	5,820	5,820	5,820	5,820	5,820	5,820	5,820
VIII	RTDR	Residential Smart Thermostat (DR)	36,934	22,986	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	RTEB	Residential Smart Thermostat Program (Behavioral)	878	627	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	RTEE	Residential Smart Thermostat (EE)	2,822	2,822	2,823	2,824	2,821	2,539	1,384	1,005	921	0	0	0	0	0	0	0
VIII	SBI2	Non-Residential Small Business Improvement Enhanced Program	3,109	3,140	3,443	3,443	3,443	3,443	3,443	3,443	3,443	3,443	2,830	1,389	550	550	550	550
IX	CAGR	Non-Residential Agricultural	2,428	2,429	2,429	2,437	2,436	2,429	2,429	2,429	2,432	1,749	1,749	1,749	1,749	1,749	1,749	1,749
IX	CBAS	Non-Res Building Automation Program	3,080	6,440	9,800	10,080	10,080	10,080	10,080	10,080	10,080	10,080	10,080	10,080	10,080	10,080	10,080	10,080
IX	CBOT	Non-Res Building Optimization	11,574	11,576	15,094	21,736	21,736	21,132	13,887	6,642	110	110	0	0	0	0	0	0
IX	CENG	Non-Res Engagement Program	3,192	6,673	10,155	10,445	10,445	10,445	10,445	9,425	6,193	2,962	0	0	0	0	0	0
IX	CNR2	Non-Residential Enhanced Prescriptive Program	19,438	19,396	19,292	19,140	5,956	1,992	1,992	1,818	1,817	1,825	1,816	1,816	1,813	1,810	1,821	1,819
IX	CNR3	Non-Residential Prescriptive Bundle	3,770	7,635	11,998	13,494	13,494	13,494	13,494	13,494	13,494	11,042	6,901	3,343	0	0	0	0
IX	EAL4	Enhancement of Residential Income and Age Qualifying	2,103	2,103	2,103	2,104	2,096	2,028	2,015	2,015	2,016	2,003	1,987	1,985	1,985	1,986	1,962	1,940
IX	EALS	Low-Income HVAC HB 2789 (Solar Component)	1,530	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039
IX	RSMH	Residential Smart Home Program	797	1,792	3,055	3,525	3,525	3,525	3,251	2,306	1,179	0	0	0	0	0	0	0
IX	RVAU	Residential Virtual Audit Program	5,250	9,916	14,582	15,136	15,136	15,136	15,136	15,136	15,136	15,136	15,136	15,136	15,136	15,136	14,322	9,056
IX	RWDR	Residential Water Savings (DR) Program	2,489	6,253	12,687	19,257	19,478	19,688	19,890	20,085	20,272	20,455	20,633	20,809	21,038	21,269	21,503	21,739
IX	RWEE	Residential Water Savings (EE) Program	1,039	2,734	5,209	5,987	5,987	5,987	5,987	5,987	5,987	5,987	5,987	5,367	3,750	1,851	0	0
X	CDAC	Non Res Data Center and Server Rooms	218	655	1,227	1,800	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,779	1,543	1,096
X	CHA4	Non-Residential Hotel and Lodging	4,366	10,893	17,996	24,166	25,622	25,622	25,622	25,622	25,622	25,622	25,622	25,622	23,681	17,546	10,633	3,396
X	CHT4	Non-Residential Health Care	5,417	13,525	22,349	30,007	31,813	31,813	31,813	31,813	31,813	31,813	31,813	31,813	31,813	31,813	29,406	21,089
X	CLT4	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	23,342	51,353	79,363	107,374	114,163	114,163	114,163	114,163	114,163	114,163	114,163	102,271	73,730	45,189	16,649	0
X	CSBB	Small Business Behavioral	5,790	8,622	7,932	7,298	3,303	0	0	0	0	0	0	0	0	0	0	0
X	RIAQ	Residential IAQ Enhancements	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
X	RLMI	Residential IAQ Home Energy Report	1,117	1,717	1,717	1,717	840	0	0	0	0	0	0	0	0	0	0	0
X	VOPT	Voltage Optimization	3,795	20,061	38,297	57,827	78,357	98,887	119,417	131,964	134,815	134,815	134,815	134,815	134,815	134,815	134,815	134,815
X	VOPT NONJU	VOPT for Non-Jurisdictional class	537	3,015	6,081	9,147	12,213	15,279	18,345	19,878	20,133	20,133	20,133	20,133	20,133	20,133	20,133	20,133
XI	CLIB	Non-Residential Income and Age Qualifying Bundle	13	26	41	60	79	95	95	95	95	95	95	95	95	95	95	92
XI	CST4	Non-Residential Custom	8,835	23,016	39,655	57,867	77,972	79,660	79,660	79,660	79,660	79,660	79,660	79,660	79,660	79,660	79,660	73,229
XI	RCEB2	Residential Customer Engagement Program (Extension)	18,683	32,180	33,904	31,191	28,696	15,034	0	0	0	0	0	0	0	0	0	0
XI	REEC3	Residential Efficient Products Marketplace Program (Extension)	2,268	5,493	9,224	13,248	17,764	19,167	19,167	19,167	19,167	19,167	19,167	19,167	17,238	13,739	9,943	5,876
XI	RLIB	Residential Income and Age Qualifying Bundle	1,972	3,707	6,183	9,037	11,891	14,269	14,269	14,269	14,269	14,269	14,269	14,269	13,794	10,940	8,086	5,232
XI	RPIL	Residential Telematics Vehicle Charger Pilot	205	715	1,568	1,995	2,019	2,041	2,062	2,083	2,103	2,122	2,141	2,159	2,181	2,205	2,229	2,254
XI	RPTR	Residential Peak Time Rebate	11,833	46,909	92,550	138,191	183,832	202,849	202,849	202,849	202,849	202,849	202,849	202,849	202,849	202,849	202,849	202,849
XII	CNCHW	Non-Residential New Construction	0	8,940	20,552	37,916	62,139	90,362	106,825	106,825	106,825	106,825	106,825	106,825	106,825	106,825	106,825	106,825
XII	RNCICF	Residential New Construction	0	2,915	7,215	11,978	17,087	22,509	24,856	24,856	24,856	24,856	24,856	24,856	24,856	24,856	24,856	24,856
XII	RSTCRDR	Residential Smart Thermostat (DR)	0	28,108	37,304	48,162	58,850	69,374	69,374	69,374	69,374	69,374	69,374	69,374	69,374	69,374	69,374	69,374
XII	RSTCREE	Residential Smart Thermostat (EE)	0	1,565	4,024	6,627	9,471	11,877	12,971	12,971	12,971	11,289	8,947	6,344	3,719	1,094	0	0
		Total	**535,797**	**714,274**	**872,311**	**1,036,847**	**1,143,440**	**1,203,324**	**1,202,673**	**1,192,601**	**1,172,958**	**1,147,376**	**1,117,372**	**1,087,500**	**1,036,546**	**969,771**	**892,708**	**791,765**

Appendix 3E-2: Active Programs Coincidental Summer Peak Savings
(kW) (System Level)

Phase	Acronym	Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
I	CHVC	Commercial HVAC Upgrade Program	2,337	2,403	1,604	28	0	0	0	0	0	0	0	0	0	0	0	0
I	CLGT	Commercial Lighting Program	120	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I	EALI	Low Income Program	724	520	323	133	42	3	0	0	0	0	0	0	0	0	0	0
II	CDUC	Commercial Duct Testing & Sealing Program	25,475	26,462	26,453	25,527	26,492	25,478	26,470	26,462	26,471	25,524	25,490	25,478	26,472	26,453	25,459	21,860
II	DG	Commercial Distributed Generation Program	6,945	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
II	EACI	Commercial Energy Audit Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
II	EAR1	Residential Home energy Check Up	3,633	2,049	665	0	0	0	0	0	0	0	0	0	0	0	0	0
II	RDUC	Residential Duct Testing & Sealing Program	121	133	133	121	133	121	133	128	125	75	40	0	0	0	0	0
II	RHEH	Heat Pump Upgrade Program	2,196	2,660	2,660	2,196	2,176	773	352	111	0	0	0	0	0	0	0	0
III	CHV2	Non-Residential Heating and Cooling Efficiency Program	10,849	11,253	11,252	10,879	11,276	10,852	9,285	5,943	2,919	1,730	4	0	0	0	0	0
III	CLT2	Non-Residential Lighting Systems & Controls Program	43,669	40,745	32,142	20,383	11,609	242	0	0	0	0	0	0	0	0	0	0
III	CSWF	Non-Residential Window Film	5,461	2,037	1,785	1,043	26	0	0	0	0	0	0	0	0	0	0	0
IV	EAL3	Income and Age Qualifying Home Improvement Program	1,153	1,249	1,249	1,153	1,249	1,153	915	329	247	238	150	45	0	0	0	0
IV	RARC	Residential Appliance Recycling Program	764	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V	RLED	Residential Retail LED Lighting Program (NC only)	694	694	694	694	694	694	694	694	694	694	694	694	694	694	305	0
V	SBIP	Small Business Improvement Program	13,246	13,285	13,285	13,315	13,334	13,254	13,286	11,481	6,726	4,011	1,408	0	0	0	0	0
VI	CNRP	Non-Residential Prescriptive Program	13,378	13,080	10,665	5,085	24	0	0	0	0	0	0	0	0	0	0	0
VII	CHV3	Non-Residential Heating and Cooling Efficiency Program	3,294	3,618	3,608	3,307	3,616	3,292	3,621	3,618	3,611	3,305	3,290	3,262	3,287	2,876	105	0
VII	CLT3	Non-Residential Lighting Systems & Controls Program	7,711	7,714	7,715	7,723	7,724	7,713	6,994	3,991	1,998	0	0	0	0	0	0	0
VII	CSW2	Non-Residential Window Film Program	146	150	150	146	151	146	79	62	58	1	0	0	0	0	0	0
VII	CTSM	Non-Residential Small Manufacturing Program	2,175	2,180	2,180	2,182	2,184	2,176	2,180	2,180	2,182	2,182	2,153	879	0	0	0	0
VII	CTSO	Non-Residential Office Program	93	98	97	93	98	93	23	0	0	0	0	0	0	0	0	0
VII	RAR2	Residential Appliance Recycling Program (v2)	396	399	399	396	242	212	149	13	0	0	0	0	0	0	0	0
VII	REE2	Residential Efficient Products Marketplace Program	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
VII	REEC	Residential Efficient Products Marketplace Program	21,006	21,166	21,166	21,000	21,160	21,005	21,166	21,166	21,163	21,000	21,001	21,005	16,124	10,909	6,113	246
VII	RTHO	Home Energy Assessment	423	449	449	423	449	423	449	449	445	376	241	75	0	0	0	0
VIII	CEEP	Non-Residential EE Products	2,153	5,844	7,382	7,382	7,382	7,382	7,382	7,382	7,382	7,382	7,382	7,382	7,382	7,382	7,382	7,382
VIII	CMFP	Non-Residential Multifamily Program	923	2,505	3,164	3,164	3,164	3,164	3,164	3,164	2,241	659	0	0	0	0	0	0
VIII	CNCR	Non-Residential New Construction	1,785	2,168	2,168	1,933	2,172	1,933	2,168	2,168	2,169	1,933	1,933	1,933	2,169	2,168	1,933	805
VIII	RCEB	Residential Customer Engagement Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	REVDR	Residential Electric Vehicle Peak Shaving (DR)	62	202	368	538	609	614	622	629	636	643	650	657	663	669	674	681
VIII	REVEE	Residential Electric Vehicle (EE)	5	6	8	8	8	8	8	8	8	8	6	2	0	0	0	0
VIII	RHR2	Residential Enhanced Home Retrofit	2,065	5,604	7,078	7,078	7,078	7,078	7,078	7,078	7,078	7,078	7,078	7,078	7,078	7,078	7,078	7,078
VIII	RHRF	Residential Home Retrofit	67	80	80	67	80	67	80	80	80	67	67	67	80	77	64	62
VIII	RHVC	Residential Low Income and Age Qualifying HVAC HB 2789	283	326	326	283	321	279	321	321	321	279	279	279	320	319	276	276
VIII	RKTS	Residential EE Kits	489	495	495	338	338	338	239	70	33	27	25	25	26	18	13	13
VIII	RMFP	Residential Multifamily Program	317	861	1,087	1,087	1,087	1,087	1,087	1,087	1,087	770	226	13	13	13	10	8
VIII	RMHP	Residential Manufactured Housing Program	95	258	326	326	326	326	231	68	1	0	0	0	0	0	0	0
VIII	RNCR	Residential New Construction	3,461	4,172	4,172	4,172	4,172	4,172	4,172	4,172	4,172	4,172	4,172	4,172	4,172	4,172	4,172	4,172
VIII	RTDR	Residential Smart Thermostat (DR)	32,180	22,986	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	RTEB	Residential Smart Thermostat Program (Behavioral)	878	627	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	RTEE	Residential Smart Thermostat (EE)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	SBI2	Non-Residential Small Business Improvement Enhanced Program	2,877	2,922	2,909	2,745	2,470	2,336	2,355	2,350	1,965	1,965	1,483	658	435	434	418	407
IX	CAGR	Non-Residential Agricultural	1,190	1,191	1,191	1,195	1,195	1,191	1,191	1,191	1,192	436	436	436	436	436	436	436
IX	CBAS	Non-Res Building Automation Program	236	639	1,043	1,211	1,211	1,211	1,211	1,211	1,211	1,211	1,211	1,211	1,211	1,211	1,211	1,211
IX	CBOT	Non-Res Building Optimization	272	334	545	633	633	510	299	88	0	0	0	0	0	0	0	0
IX	CENG	Non-Res Engagement Program	244	662	1,081	1,255	1,255	1,255	1,255	1,011	593	174	0	0	0	0	0	0
IX	CNR2	Non-Residential Enhanced Prescriptive Program	12,878	14,663	14,590	12,623	3,988	1,701	1,776	1,615	1,614	1,550	1,543	1,543	1,611	1,608	1,547	1,546
IX	CNR3	Non-Residential Prescriptive Bundle	2,616	7,099	11,583	13,451	13,451	13,451	13,451	13,451	13,451	10,836	6,352	1,868	0	0	0	0
IX	EAL4	Enhancement of Residential Income and Age Qualifying	793	929	929	788	905	706	835	835	829	684	675	672	800	799	664	660
IX	EALS	Low-Income HVAC HB 2789 (Solar Component)	794	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360
IX	RSMH	Residential Smart Home Program	137	405	732	879	879	879	742	473	146	0	0	0	0	0	0	0
IX	RVAU	Residential Virtual Audit Program	872	2,270	3,598	4,152	4,152	4,152	4,152	4,152	4,152	4,152	4,152	4,152	4,152	4,152	3,280	1,882
IX	RWDR	Residential Water Savings (DR) Program	1,723	4,685	10,007	16,520	19,386	19,601	19,806	20,004	20,194	20,379	20,559	20,736	20,942	21,173	21,405	21,641
IX	RWEE	Residential Water Savings (EE) Program	428	1,425	2,869	3,549	3,549	3,549	3,549	3,549	3,549	3,549	3,549	3,121	2,125	680	0	0
X	CDAC	Non Res Data Center and Server Rooms	75	277	579	915	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	980	777	475
X	CHA4	Non-Residential Hotel and Lodging	3,396	9,766	16,793	23,196	25,622	25,622	25,622	25,622	25,622	25,622	25,622	25,622	22,226	15,856	8,829	2,426
X	CHT4	Non-Residential Health Care	4,213	12,124	20,855	28,804	31,813	31,813	31,813	31,813	31,813	31,813	31,813	31,813	31,813	31,813	27,600	19,689
X	CLT4	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	8,961	24,323	39,685	55,047	61,448	61,448	61,448	61,448	61,448	61,448	61,448	52,487	37,125	21,763	6,401	0
X	CSBB	Small Business Behavioral	5,039	8,235	7,576	6,970	2,803	0	0	0	0	0	0	0	0	0	0	0
X	RIAQ	Residential IAQ Enhancements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
X	RLMI	Residential IAQ Home Energy Report	996	1,707	1,707	1,707	711	0	0	0	0	0	0	0	0	0	0	0
X	VOPT	Voltage Optimization	544	16,669	37,080	57,491	77,902	98,314	118,725	131,198	134,033	134,033	134,033	134,033	134,033	134,033	134,033	134,033
X	VOPT NONJU	VOPT for Non-Jurisdictional class	388	2,326	5,174	8,022	10,870	13,719	16,567	18,307	18,703	18,703	18,703	18,703	18,703	18,703	18,703	18,703
XI	CLIB	Non-Residential Income and Age Qualifying Bundle	3	8	13	18	23	25	25	25	25	25	25	25	25	25	25	22
XI	CST4	Non-Residential Custom	676	2,157	4,094	6,219	8,558	9,573	9,573	9,573	9,573	9,573	9,573	9,573	9,573	9,573	9,573	8,936
XI	RCEB2	Residential Customer Engagement Program (Extension)	15,668	31,508	33,204	30,547	28,103	11,300	0	0	0	0	0	0	0	0	0	0
XI	REEC3	Residential Efficient Products Marketplace Program (Extension)	1,768	4,677	7,947	11,414	15,040	16,513	16,513	16,513	16,513	16,554	16,513	16,513	14,852	11,837	8,566	5,112
XI	RLIB	Residential Income and Age Qualifying Bundle	303	772	1,260	1,836	2,348	2,439	2,439	2,439	2,439	2,562	2,562	2,439	2,154	1,667	1,238	726
XI	RPIL	Residential Telematics Vehicle Charger Pilot	205	715	1,568	1,995	2,019	2,041	2,062	2,083	2,103	2,122	2,141	2,159	2,181	2,205	2,229	2,254
XI	RPTR	Residential Peak Time Rebate	11,833	46,909	92,550	138,191	183,832	202,849	202,849	202,849	202,849	202,849	202,849	202,849	202,849	202,849	202,849	202,849
XII	CNCHW	Non-Residential New Construction	0	2,374	6,122	11,055	17,816	25,339	28,473	28,473	28,473	28,473	28,473	28,473	28,473	28,473	28,473	28,473
XII	RNCICF	Residential New Construction	0	2,445	6,835	11,568	16,647	22,043	24,343	24,343	24,343	24,343	24,343	24,343	24,343	24,343	24,343	24,343
XII	RSTCRDR	Residential Smart Thermostat (DR)	0	16,397	32,770	43,638	54,397	64,989	69,374	69,374	69,374	69,374	69,374	69,374	69,374	69,374	69,374	69,374
XII	RSTCREE	Residential Smart Thermostat (EE)	0	1,409	3,623	5,967	8,270	10,695	11,679	11,679	11,679	10,279	8,056	5,712	3,348	985	0	0
		Total	**290,034**	**421,994**	**537,338**	**647,302**	**733,263**	**765,892**	**787,025**	**791,074**	**782,285**	**767,411**	**754,327**	**734,111**	**703,815**	**669,295**	**627,055**	**589,276**

* Includes DSM savings from persistent and new incremental savings.

Appendix 3E-3: Active Programs Energy Savings
(MWh) (System Level)

Phase	Acronym	Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
I	CHVC	Commercial HVAC Upgrade Program	6,240	6,164	4,225	364	0	0	0	0	0	0	0	0	0	0	0	0
I	CLGT	Commercial Lighting Program	553	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I	EALI	Low Income Program	6,612	4,496	2,776	1,672	602	85	0	0	0	0	0	0	0	0	0	0
II	CDUC	Commercial Duct Testing & Sealing Program	75,526	75,527	75,527	75,528	75,527	75,526	75,527	75,527	75,528	75,527	75,527	75,526	75,527	75,522	75,133	65,082
II	DG	Commercial Distributed Generation Program	314	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
II	EACI	Commercial Energy Audit Program	148	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
II	EAR1	Residential Home energy Check Up	29,027	15,103	5,861	101	0	0	0	0	0	0	0	0	0	0	0	0
II	RDUC	Residential Duct Testing & Sealing Program	937	937	937	937	937	937	936	909	856	539	166	5	0	0	0	0
II	RHEH	Heat Pump Upgrade Program	14,486	14,486	14,486	14,462	11,961	5,344	1,936	879	32	0	0	0	0	0	0	0
III	CHV2	Non-Residential Heating and Cooling Efficiency Program	35,084	35,086	35,086	35,087	35,086	35,012	30,209	21,380	13,050	7,050	708	0	0	0	0	0
III	CLT2	Non-Residential Lighting Systems & Controls Program	216,388	201,957	159,470	106,774	61,522	11,261	147	0	0	0	0	0	0	0	0	0
III	CSWF	Non-Residential Window Film	5,562	2,042	1,779	952	73	1	0	0	0	0	0	0	0	0	0	0
IV	EAL3	Income and Age Qualifying Home Improvement Program	10,794	10,794	10,794	10,794	10,794	10,674	8,299	4,224	2,825	2,757	1,801	515	150	0	0	0
IV	RARC	Residential Appliance Recycling Program	5,932	526	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V	RLED	Residential Retail LED Lighting Program (NC only)	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	6,966	3,167	0
V	SBIP	Small Business Improvement Program	54,121	54,121	54,121	54,121	54,121	54,121	54,070	47,014	29,923	16,056	5,956	162	0	0	0	0
VI	CNRP	Non-Residential Prescriptive Program	44,312	38,871	33,171	14,120	1,759	0	0	0	0	0	0	0	0	0	0	0
VII	CHV3	Non-Residential Heating and Cooling Efficiency Program	21,831	21,834	21,834	21,837	21,834	21,831	21,834	21,834	21,837	21,834	21,834	21,244	19,931	17,728	7,259	0
VII	CLT3	Non-Residential Lighting Systems & Controls Program	47,670	47,670	47,670	47,670	47,670	47,670	43,265	25,907	14,253	1,819	0	0	0	0	0	0
VII	CSW2	Non-Residential Window Film Program	506	506	506	506	506	506	377	226	197	19	0	0	0	0	0	0
VII	CTSM	Non-Residential Small Manufacturing Program	12,404	12,404	12,404	12,405	12,404	12,404	12,404	12,404	12,405	12,404	12,231	6,113	476	0	0	0
VII	CTSO	Non-Residential Office Program	12,042	12,041	12,041	12,033	10,882	10,269	3,780	0	0	0	0	0	0	0	0	0
VII	RAR2	Residential Appliance Recycling Program (v2)	2,907	2,907	2,907	2,784	1,766	1,568	1,109	167	0	0	0	0	0	0	0	0
VII	REE2	Residential Efficient Products Marketplace Program	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	979
VII	REEC	Residential Efficient Products Marketplace Program	270,736	270,738	270,738	270,740	270,738	270,736	270,738	270,738	270,740	270,738	270,738	270,736	230,119	152,121	86,006	14,615
VII	RTHO	Home Energy Assessment	14,112	14,113	14,113	14,113	14,113	14,113	14,113	14,113	13,967	12,501	7,307	2,338	124	0	0	0
VIII	CEEP	Non-Residential EE Products	6,477	11,636	14,021	14,021	14,044	14,021	14,021	14,021	14,060	14,011	13,815	13,058	12,606	12,572	12,472	12,295
VIII	CMFP	Non-Residential Multifamily Program	9,628	26,674	34,460	34,460	34,502	34,460	34,460	34,372	25,012	7,786	0	0	0	0	0	0
VIII	CNCR	Non-Residential New Construction	31,496	34,953	34,953	34,953	34,957	34,953	34,953	34,953	34,979	34,942	34,942	34,953	34,975	34,953	24,502	3,458
VIII	RCEB	Residential Customer Engagement Program	1,322	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	REVDR	Residential Electric Vehicle Peak Shaving (DR)	2	7	12	17	19	20	20	20	20	21	21	21	21	21	22	22
VIII	REVEE	Residential Electric Vehicle (EE)	159	376	503	503	504	503	503	501	484	453	344	127	0	0	0	0
VIII	RHR2	Residential Enhanced Home Retrofit	9,880	27,650	35,548	35,548	35,629	35,548	35,548	35,548	35,630	35,551	35,551	35,548	35,626	35,548	35,548	35,551
VIII	RHRF	Residential Home Retrofit	418	418	418	417	416	415	415	415	414	414	414	414	410	395	379	367
VIII	RHVC	Residential Low Income and Age Qualifying HVAC HB 2789	2,638	2,638	2,638	2,637	2,609	2,241	1,677	1,451	1,380	1,380	1,380	1,379	1,373	1,349	1,329	1,284
VIII	RKTS	Residential EE Kits	8,275	10,597	11,077	8,744	6,684	5,206	3,927	1,586	416	336	317	317	305	233	189	179
VIII	RMFP	Residential Multifamily Program	2,042	4,873	6,286	6,194	6,046	6,008	5,998	5,902	5,857	4,397	1,551	137	137	128	108	83
VIII	RMHP	Residential Manufactured Housing Program	348	807	1,031	1,030	997	927	692	233	8	3	2	2	2	1	1	1
VIII	RNCR	Residential New Construction	18,720	23,135	23,135	23,135	23,157	23,135	23,135	23,135	23,157	23,135	23,135	23,135	23,157	23,135	23,135	23,135
VIII	RTDR	Residential Smart Thermostat (DR)	314	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	RTEB	Residential Smart Thermostat Program (Behavioral)	1,009	537	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	RTEE	Residential Smart Thermostat (EE)	3,748	4,397	4,397	4,397	4,339	3,539	2,221	1,339	658	0	0	0	0	0	0	0
VIII	SBI2	Non-Residential Small Business Improvement Enhanced Program	15,435	20,274	22,423	22,218	21,835	21,672	21,671	21,262	17,694	13,536	8,055	3,963	2,119	2,114	2,114	2,093
IX	CAGR	Non-Residential Agricultural	6,985	8,845	10,707	11,596	11,595	11,596	11,595	11,594	11,137	6,322	6,170	6,197	6,225	6,197	6,197	6,168
IX	CBAS	Non-Res Building Automation Program	2,171	6,436	10,704	12,803	12,836	12,803	12,803	12,803	12,881	12,772	12,772	12,803	12,874	12,803	12,803	12,772
IX	CBOT	Non-Res Building Optimization	19,548	29,583	39,630	44,832	37,217	25,535	15,489	5,442	121	46	0	0	0	0	0	0
IX	CENG	Non-Res Engagement Program	2,250	6,669	11,092	13,266	13,300	13,266	13,266	11,019	6,645	2,173	0	0	0	0	0	0
IX	CNR2	Non-Residential Enhanced Prescriptive Program	21,969	21,969	21,922	20,971	5,944	3,926	3,894	2,715	2,280	2,280	2,278	2,228	2,087	2,087	2,087	2,087
IX	CNR3	Non-Residential Prescriptive Bundle	12,547	35,432	58,330	68,671	68,721	68,671	68,671	68,671	68,899	56,057	33,205	10,362	0	0	0	0
IX	EAL4	Enhancement of Residential Income and Age Qualifying	6,113	6,113	6,113	6,096	5,965	5,585	5,566	5,566	5,506	5,318	5,217	5,204	5,204	5,184	5,093	5,041
IX	EALS	Low-Income HVAC HB 2789 (Solar Component)	2,294	3,651	3,651	3,651	3,657	3,651	3,651	3,651	3,659	3,651	3,651	3,651	3,659	3,651	3,651	3,651
IX	RSMH	Residential Smart Home Program	2,422	7,528	13,765	16,945	16,998	16,930	14,537	9,422	3,203	0	0	0	0	0	0	0
IX	RVAU	Residential Virtual Audit Program	17,172	38,117	57,922	67,099	66,985	66,375	65,618	65,216	65,274	64,161	63,209	63,202	63,404	63,144	50,857	29,485
IX	RWDR	Residential Water Savings (DR) Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IX	RWEE	Residential Water Savings (EE) Program	3,298	9,771	19,192	23,898	23,956	23,898	23,898	23,898	23,946	23,728	23,588	20,874	14,284	4,706	0	0
X	CDAC	Non Res Data Center and Server Rooms	733	2,831	6,020	9,606	11,294	11,270	11,270	11,270	11,313	11,254	11,254	11,270	11,308	10,537	8,439	5,244
X	CHA4	Non-Residential Hotel and Lodging	8,360	25,213	43,882	61,111	68,523	68,266	68,266	68,266	68,523	68,266	68,266	68,266	60,125	43,052	24,381	7,155
X	CHT4	Non-Residential Health Care	9,900	29,881	52,026	72,444	81,219	80,919	80,919	80,919	81,219	80,919	80,919	80,919	81,180	80,919	71,022	51,033
X	CLT4	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	61,022	135,913	210,844	285,785	319,956	319,929	319,929	319,929	321,378	318,059	299,797	258,987	184,707	109,085	34,144	0
X	CSBB	Small Business Behavioral	9,330	15,869	14,599	13,430	5,681	0	0	0	0	0	0	0	0	0	0	0
X	RIAQ	Residential IAQ Enhancements	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
X	RLMI	Residential IAQ Home Energy Report	756	1,288	1,288	1,288	531	0	0	0	0	0	0	0	0	0	0	0
X	VOPT	Voltage Optimization	6,180	72,603	165,591	258,575	352,388	444,544	537,532	596,590	612,167	610,839	610,839	610,617	612,516	610,617	610,617	610,839
X	VOPT NONJU	VOPT for Non-Jurisdictional class	3,091	24,112	55,006	85,901	116,900	147,678	178,572	198,198	203,428	202,884	202,884	202,861	203,478	202,861	202,861	202,884
XI	CLIB	Non-Residential Income and Age Qualifying Bundle	11	32	54	75	97	107	107	107	108	107	107	107	107	107	107	96
XI	CST4	Non-Residential Custom	5,855	21,289	41,556	63,817	88,443	100,909	100,909	100,909	101,525	100,665	100,665	100,909	101,465	100,909	100,909	94,840
XI	RCEB2	Residential Customer Engagement Program (Extension)	26,955	56,476	60,084	55,275	51,000	21,775	0	0	0	0	0	0	0	0	0	0
XI	REEC3	Residential Efficient Products Marketplace Program (Extension)	5,508	16,420	28,274	40,855	54,064	60,089	60,089	60,089	60,256	60,087	60,087	60,089	54,771	43,672	31,817	19,233
XI	RLIB	Residential Income and Age Qualifying Bundle	788	2,329	3,871	5,413	6,949	7,710	7,710	7,710	7,730	7,702	7,702	7,710	6,931	5,381	3,839	2,295
XI	RPIL	Residential Telematics Vehicle Charger Pilot	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
XI	RPTR	Residential Peak Time Rebate	3	12	24	37	49	53	53	55	55	55	49	53	55	55	55	55
XII	CNCHW	Non-Residential New Construction	0	15,516	43,888	79,593	128,771	183,877	208,891	208,891	209,533	208,792	208,792	208,891	209,422	208,891	208,891	208,792
XII	RNCICF	Residential New Construction	0	4,201	12,110	20,640	29,872	39,515	43,946	43,946	44,043	43,967	43,967	43,946	44,032	43,946	43,946	43,967
XII	RSTCRDR	Residential Smart Thermostat (DR)	0	0	0	-1	0	0	0	0	0	0	0	0	0	0	0	0
XII	RSTCREE	Residential Smart Thermostat (EE)	0	1,043	2,876	4,747	6,643	8,522	9,325	9,325	9,336	8,280	6,447	4,576	2,694	803	0	0
		Total	**1,243,757**	**1,618,965**	**1,974,712**	**2,242,034**	**2,415,927**	**2,510,447**	**2,592,833**	**2,604,602**	**2,557,888**	**2,463,932**	**2,375,999**	**2,281,757**	**2,125,930**	**1,922,469**	**1,694,155**	**1,464,784**

* Includes DSM savings from persistent and new incremental savings.

Appendix 3E-4: Active Programs Penetrations
(System Level)

Phase	Acronym	Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
II	DG	Commercial Distributed Generation Program	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	CEEP	Non-Residential EE Products	282	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
VIII	CMFP	Non-Residential Multifamily Program	1,621	3,242	3,242	3,242	3,242	3,242	3,242	3,242	1,621	0	0	0	0	0	0	0
VIII	CNCR	Non-Residential New Construction	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	0
VIII	REVDR	Residential Electric Vehicle Peak Shaving (DR)	477	1,216	1,970	2,739	2,739	2,774	2,808	2,841	2,874	2,905	2,935	2,964	2,991	3,017	3,041	3,076
VIII	REVEE	Residential Electric Vehicle (EE)	1,607	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	2,361	0	0	0	0	0
VIII	RHR2	Residential Enhanced Home Retrofit	13,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000
VIII	RKTS	Residential EE Kits	30,000	60,000	60,000	60,000	60,000	60,000	30,000	0	0	0	0	0	0	0	0	0
VIII	RMFP	Residential Multifamily Program	13,158	26,316	26,316	26,316	26,316	26,316	26,316	26,316	26,316	13,158	0	0	0	0	0	0
VIII	RMHP	Residential Manufactured Housing Program	2,256	4,512	4,512	4,512	4,512	4,512	2,256	0	0	0	0	0	0	0	0	0
VIII	RNCR	Residential New Construction	4,893	4,893	4,893	4,893	4,893	4,893	4,893	4,893	4,893	4,893	4,893	4,893	4,893	4,893	4,893	4,893
VIII	RTDR	Residential Smart Thermostat (DR)	38,473	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	RTEB	Residential Smart Thermostat Program (Behavioral)	8,637	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIII	RTEE	Residential Smart Thermostat (EE)	4,735	4,735	4,735	4,735	4,735	4,735	4,735	4,735	0	0	0	0	0	0	0	0
VIII	SBI2	Non-Residential Small Business Improvement Enhanced Program	675	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	675	0	0	0	0	0
IX	CAGR	Non-Residential Agricultural	142	284	426	426	426	426	426	426	426	426	426	426	426	426	426	426
IX	CBAS	Non-Res Building Automation Program	30	60	90	90	90	90	90	90	90	90	90	90	90	90	90	90
IX	CBOT	Non-Res Building Optimization	30	60	90	90	90	60	30	0	0	0	0	0	0	0	0	0
IX	CENG	Non-Res Engagement Program	57	114	171	171	171	171	171	114	57	0	0	0	0	0	0	0
IX	CNR3	Non-Residential Prescriptive Bundle	700	1,400	2,100	2,100	2,100	2,100	2,100	2,100	2,100	1,400	700	0	0	0	0	0
IX	EALS	Low-Income HVAC HB 2789 (Solar Component)	555	555	555	555	555	555	555	555	555	555	555	555	555	555	555	555
IX	RSMH	Residential Smart Home Program	10,268	23,104	38,507	38,507	38,507	38,507	28,239	15,403	0	0	0	0	0	0	0	0
IX	RVAU	Residential Virtual Audit Program	45,000	85,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	80,000	40,000
IX	RWDR	Residential Water Savings (DR) Program	2,419	6,353	11,801	12,077	12,232	12,387	12,540	12,690	12,835	12,975	13,108	13,236	13,357	13,473	13,583	13,737
IX	RWEE	Residential Water Savings (EE) Program	3,600	9,400	17,400	17,400	17,400	17,400	17,400	17,400	17,400	17,400	17,400	13,800	8,000	0	0	0
X	CDAC	Non Res Data Center and Server Rooms	8	24	45	66	66	66	66	66	66	66	66	66	66	58	42	21
X	CHA4	Non-Residential Hotel and Lodging	217	469	738	955	955	955	955	955	955	955	955	955	738	486	217	0
X	CHT4	Non-Residential Health Care	257	556	875	1,132	1,132	1,132	1,132	1,132	1,132	1,132	1,132	1,132	1,132	1,132	875	576
X	CLT4	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	970	1,940	2,910	3,880	3,880	3,880	3,880	3,880	3,880	3,880	3,880	2,910	1,940	970	0	0
X	CSBB	Small Business Behavioral	41,400	38,088	35,041	32,238	0	0	0	0	0	0	0	0	0	0	0	0
X	RLMI	Residential IAQ Home Energy Report	3,500	3,500	3,500	3,500	0	0	0	0	0	0	0	0	0	0	0	0
X	VOPT	Voltage Optimization	35	185	335	485	635	785	935	985	985	985	985	985	985	985	985	985
XI	CLIB	Non-Residential Income and Age Qualifying Bundle	210	210	420	630	840	840	840	840	840	840	840	840	840	840	840	630
XI	CST4	Non-Residential Custom	52	139	235	340	456	456	456	456	456	456	456	456	456	456	456	404
XI	RCEB2	Residential Customer Engagement Program (Extension)	265,431	344,197	316,661	291,328	268,022	0	0	0	0	0	0	0	0	0	0	0
XI	REEC3	Residential Efficient Products Marketplace Program (Extension)	206,049	432,703	676,355	932,192	1,194,427	1,194,427	1,194,427	1,194,427	1,194,427	1,194,427	1,194,427	1,194,427	988,378	761,724	518,072	262,235
XI	RLIB	Residential Income and Age Qualifying Bundle	14,154	28,308	42,462	56,616	70,770	70,770	70,770	70,770	70,770	70,770	70,770	70,770	56,616	42,462	28,308	14,154
XI	RPIL	Residential Telematics Vehicle Charger Pilot	333	1,000	2,000	2,026	2,052	2,078	2,104	2,129	2,153	2,177	2,199	2,220	2,241	2,260	2,279	2,304
XI	RPTR	Residential Peak Time Rebate	25,000	81,250	137,500	193,750	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
XII	CNCHW	Non-Residential New Construction	0	55	110	191	298	405	405	405	405	405	405	405	405	405	405	405
XII	RNCICF	Residential New Construction	0	3,550	7,390	11,520	15,945	20,620	20,620	20,620	20,620	20,620	20,620	20,620	20,620	20,620	20,620	20,620
XII	RSTCRDR	Residential Smart Thermostat (DR)	0	35,557	50,202	64,813	79,197	93,360	93,360	93,360	93,360	93,360	93,360	93,360	93,360	93,360	93,360	93,360
XII	RSTCREE	Residential Smart Thermostat (EE)	0	8,360	16,890	25,590	34,290	42,990	42,990	42,990	42,990	34,630	26,100	17,400	8,700	0	0	0
		Total	**740,387**	**1,243,367**	**1,627,509**	**1,956,137**	**2,258,005**	**2,017,964**	**1,975,773**	**1,930,852**	**1,909,238**	**1,885,536**	**1,861,053**	**1,844,224**	**1,608,503**	**1,349,925**	**1,045,761**	**735,035**

Appendix 3F: Description of Recently Approved DSM Programs

Residential New Construction Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	Recently Approved
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 recently approved 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 active 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:	Recently Approved
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 recently approved 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 active 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:	Recently Approved
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 active 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:	Recently Approved
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 active DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events.

Appendix 3F-1: Recently Approved Programs Non-Coincidental Peak Savings (kW) (System Level)

Phase	Acronym	Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
VIII	CEEP	Non-Residential EE Products	9,603	13,084	14,147	14,147	14,147	14,147	14,147	14,147	14,147	14,147	14,147	14,147	14,147	14,147	14,147	14,147
XII	CNCHW	Non-Residential New Construction	0	8,961	21,682	40,002	65,557	95,332	112,701	112,701	112,701	112,701	112,701	112,701	112,701	112,701	112,701	112,701
XII	RNCICF	Residential New Construction	0	2,922	7,231	12,005	17,125	22,559	24,912	24,912	24,912	24,912	24,912	24,912	24,912	24,912	24,912	24,912
XII	RSTCRDR	Residential Smart Thermostat (DR)	0	28,172	39,775	51,351	62,748	73,969	67,805	0	0	0	0	0	0	0	0	0
XII	RSTCREE	Residential Smart Thermostat (EE)	0	1,569	4,290	7,066	10,098	12,664	13,830	13,830	13,830	12,037	9,540	6,764	3,965	1,166	0	0
		Total	**9,603**	**54,707**	**87,125**	**124,571**	**169,675**	**218,671**	**233,395**	**165,590**	**165,590**	**163,797**	**161,300**	**158,524**	**155,725**	**152,926**	**151,760**	**151,760**

Appendix 3F-2: Recently Approved Programs Coincidental Peak Savings (kW) (System Level)

Phase	Acronym	Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
VIII	CEEP	Non-Residential EE Products	9,326	12,771	13,850	13,850	13,850	13,850	13,850	13,850	13,850	13,850	13,850	13,850	13,850	13,850	13,850	13,850
XII	CNCHW	Non-Residential New Construction	0	2,380	6,459	11,663	18,796	26,732	30,039	30,039	30,039	30,039	30,039	30,039	30,039	30,039	30,039	30,039
XII	RNCICF	Residential New Construction	0	2,450	6,851	11,594	16,685	22,093	24,398	24,398	24,398	24,398	24,398	24,398	24,398	24,398	24,398	24,398
XII	RSTCRDR	Residential Smart Thermostat (DR)	0	16,433	34,940	46,528	57,999	69,293	30,820	0	0	0	0	0	0	0	0	0
XII	RSTCREE	Residential Smart Thermostat (EE)	0	1,413	3,863	6,363	8,818	11,403	12,453	12,453	12,453	10,959	8,590	6,090	3,570	1,050	0	0
		Total	**9,326**	**35,447**	**65,963**	**89,998**	**116,147**	**143,371**	**111,560**	**80,740**	**80,740**	**79,246**	**76,877**	**74,377**	**71,857**	**69,337**	**68,287**	**68,287**

Appendix 3F-3: Recently Approved Programs Energy Savings (MWh) (System Level)

Phase	Acronym	Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
VIII	CEEP	Non-Residential EE Products	7,413	11,494	13,216	13,216	13,249	13,216	13,216	13,216	13,263	13,210	13,210	13,216	13,258	13,216	13,216	13,210
XII	CNCHW	Non-Residential New Construction	0	15,551	43,987	79,772	129,061	184,291	209,362	209,362	210,005	209,263	209,263	209,362	209,894	209,362	209,362	209,263
XII	RNCICF	Residential New Construction	0	4,210	12,137	20,686	29,939	39,604	44,045	44,045	44,142	44,067	44,067	44,045	44,132	44,045	44,045	44,067
XII	RSTCRDR	Residential Smart Thermostat (DR)	0	0	0	0	0	-4	6	0	0	0	0	0	0	0	0	0
XII	RSTCREE	Residential Smart Thermostat (EE)	0	1,045	2,883	4,757	6,657	8,542	9,346	9,346	9,357	8,299	6,461	4,587	2,700	805	0	0
		Total	**7,413**	**32,301**	**72,223**	**118,432**	**178,907**	**245,649**	**275,975**	**275,969**	**276,767**	**274,838**	**273,001**	**271,210**	**269,984**	**267,428**	**266,623**	**266,539**

Appendix 3F-4: Recently Approved Programs Penetrations
(System Level)

Phase	Acronym	Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
VIII	CEEP	Non-Residential EE Products	684	966	966	966	966	966	966	966	966	966	966	966	966	966	966	966
XII	CNCHW	Non-Residential New Construction	0	55	110	191	298	405	405	405	405	405	405	405	405	405	405	405
XII	RNCICF	Residential New Construction	0	3,550	7,390	11,520	15,945	20,620	20,620	20,620	20,620	20,620	20,620	20,620	20,620	20,620	20,620	20,620
XII	RSTCRDR	Residential Smart Thermostat (DR)	0	35,557	50,202	64,813	79,197	93,360	0	0	0	0	0	0	0	0	0	0
XII	RSTCREE	Residential Smart Thermostat (EE)	0	8,360	16,890	25,590	34,290	42,990	42,990	42,990	42,990	34,630	26,100	17,400	8,700	0	0	0
		Total	**684**	**48,488**	**75,558**	**103,080**	**130,696**	**158,341**	**64,981**	**64,981**	**64,981**	**56,621**	**48,091**	**39,391**	**30,691**	**21,991**	**21,991**	**21,991**

Appendix 3G-1: Forecasted Growth EE Coincidental Peak Savings (kW) (System Level)

Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Generic Undesignated EE Programs	0	0	0	0	0	0	0	20,079	50,969	88,232	126,323	189,821	250,469	321,793	432,925	616,026
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**20,079**	**50,969**	**88,232**	**126,323**	**189,821**	**250,469**	**321,793**	**432,925**	**616,026**

Appendix 3G-2: Forecasted Growth EE Energy Savings
(MWh) (System Level)

Programs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Generic Undesignated EE Programs	0	0	0	0	0	0	0	106,527	267,457	443,133	604,669	876,678	1,109,707	1,369,808	1,623,221	1,926,839
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**106,527**	**267,457**	**443,133**	**604,669**	**876,678**	**1,109,707**	**1,369,808**	**1,623,221**	**1,926,839**

Appendix 3H - Rejected DSM Programs

Program
Non-Residential HVAC Tune-Up Program
Energy Management System Program
ENERGY STAR® New Homes Program
Geo-Thermal Heat Pump Program
Home Energy Comparison Program
Home Performance with ENERGY STAR® Program
In-Home Energy Display Program
Premium Efficiency Motors Program
Residential Refrigerator Turn-In Program
Residential Solar Water Heating Program
Residential Water Heater Cycling Program
Residential Comprehensive Energy Audit Program
Residential Radiant Barrier Program
Residential Lighting (Phase II) Program
Non-Residential Refrigeration Program
Cool Roof Program
Non-Residential Data Centers Program
Non-Residential Curtailable Service
Non-Residential Custom Incentive
Enhanced Air Conditioner Direct Load Control Program
Residential Programmable Thermostat Program
Residential Controllable Thermostat Program
Residential Retail LED Lighting Program (VA)
Residential New Homes Program
Residential Home Energy Assessment
Non-Residential Re-commissioning Program
Non-Residential Compressed Air System Program
Non-Residential Strategic Energy Management
Non-Residential Agricultural EE
Non-Residential Telecommunication Optimization
Residential Bring Your Own Device
Non-Residential Battery Storage
Residential Battery Storage
Non-Residential DR Outreach
Residential Water Heating

Appendix 3I: DSM Program Projected Savings By 2029

Phase	Program	Projected MW Reduction		Projected GWh Savings	Program Status
		Winter	Summer		
I	Low Income Program	0.05	0.00	0.09	Inactive
II	Commercial Distributed Generation Program	0.00	0.00	0.00	Active
	Commercial Duct Testing & Sealing Program	20.89	26.68	75.53	Inactive
	Heat Pump Upgrade Program	1.50	0.84	5.34	Inactive
	Residential Duct Testing & Sealing Program	0.27	0.14	0.94	Inactive
III	Non-Residential Heating and Cooling Efficiency Program	14.04	11.03	35.01	Inactive
	Non-Residential Lighting Systems & Controls Program	7.48	0.24	11.26	Inactive
	Non-Residential Window Film	0.00	0.00	0.00	Inactive
IV	Income and Age Qualifying Home Improvement Program	2.10	1.18	10.67	Inactive
V	Residential Retail LED Lighting Program (NC only)	1.13	0.69	7.27	Inactive
	Small Business Improvement Program	9.66	13.87	54.12	Inactive
VII	Home Energy Assessment	1.66	0.42	14.11	Active
	Non-Residential Heating and Cooling Efficiency Program	20.33	3.31	21.83	Active
	Non-Residential Lighting Systems & Controls Program	7.50	7.91	47.67	Inactive
	Non-Residential Office Program	0.07	0.09	10.27	Active
	Non-Residential Small Manufacturing Program	1.76	2.23	12.40	Active
	Non-Residential Window Film Program	0.00	0.15	0.51	Active
	Residential Appliance Recycling Program (v2)	0.15	0.21	1.57	Active
	Residential Efficient Products Marketplace Program	0.11	0.14	1.07	Active
	Residential Efficient Products Marketplace Program	38.54	21.38	270.74	Inactive
VIII	Non-Residential EE Products	3.98	8.53	14.02	Active
	Non-Residential Multifamily Program	4.92	3.20	34.46	Active
	Non-Residential New Construction	4.91	3.85	34.95	Active
	Non-Residential Small Business Improvement Enhanced Program	3.36	4.75	21.67	Active
	Residential EE Kits	0.86	0.40	5.21	Active
	Residential Electric Vehicle (EE)	0.02	0.01	0.50	Active
	Residential Electric Vehicle Peak Shaving (DR)	0.00	0.61	0.02	Active
	Residential Enhanced Home Retrofit	2.65	7.53	35.55	Active
	Residential Home Retrofit	0.11	0.07	0.42	Active
	Residential Low Income and Age Qualifying HVAC HB 2789	0.85	0.28	2.24	Active
	Residential Manufactured Housing Program	0.28	0.33	0.93	Active
	Residential Multifamily Program	1.78	1.10	5.18	Active
	Residential New Construction	2.39	7.60	23.03	Active
	Residential Smart Thermostat (DR)	0.00	0.00	0.00	Active
	Residential Smart Thermostat (EE)	2.38	0.00	3.63	Active
	Residential Smart Thermostat Program (Behavioral)	0.00	0.00	0.00	Active
IX	Enhancement of Residential Income and Age Qualifying	1.49	0.72	5.58	Active
	Low-Income HVAC HB 2789 (Solar Component)	0.03	1.64	3.65	Active
	Non-Res Building Automation Program	6.01	1.29	12.80	Active
	Non-Res Building Optimization	22.54	0.54	25.53	Active
	Non-Res Engagement Program	6.22	1.34	13.27	Active
	Non-Residential Agricultural	2.51	1.63	11.60	Active
	Non-Residential Enhanced Prescriptive Program	0.54	1.70	3.93	Active
	Non-Residential Prescriptive Bundle	10.47	14.31	68.67	Active
	Residential Smart Home Program	1.34	0.93	16.93	Active
	Residential Virtual Audit Program	16.88	4.89	66.36	Active
	Residential Water Savings (DR) Program	20.74	20.85	0.00	Active
	Residential Water Savings (EE) Program	2.00	3.87	23.85	Active
XII	Non-Residential Health Care	15.74	31.81	80.92	Active
	Non-Residential Hotel and Lodging	13.61	25.62	68.27	Active
	Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	50.53	68.72	320.00	Active
	Non Res Data Center and Server Rooms	1.78	1.05	11.27	Active
	Residential IAQ Enhancements	0.00	0.00	0.00	Active
	Residential IAQ Home Energy Report	0.00	0.00	0.00	Active
	Small Business Behavioral	0.00	0.00	0.00	Active
	Voltage Optimization	74.63	98.31	444.54	Active
	VOPT for Non-Jurisdictional class	9.18	11.29	66.68	Active

Appendix 3I: DSM Program Projected Savings By 2029

Phase	Program	Projected MW Reduction		Projected GWh Savings	Program Status
		Winter	Summer		
XII	Non-Residential Custom	47.33	10.16	100.91	Active
	Non-Residential Income and Age Qualifying Bundle	0.05	0.03	0.11	Active
	Residential Customer Engagement Program (Extension)	7.58	11.30	21.78	Active
	Residential Efficient Products Marketplace Program (Extension)	9.68	17.57	60.09	Active
	Residential Income and Age Qualifying Bundle	10.03	2.59	7.71	Active
	Residential Peak Time Rebate	28.83	215.80	0.05	Active
	Residential Telematics Vehicle Charger Pilot	2.16	2.17	0.00	Active
XII	Non-Residential New Construction	24.22	26.67	183.88	Proposed
	Residential New Construction	5.88	22.04	39.51	Proposed
	Residential Smart Thermostat (DR)	63.54	69.14	0.00	Proposed
	Residential Smart Thermostat (EE)	1.15	11.38	8.52	Proposed

National Comparison Analyses

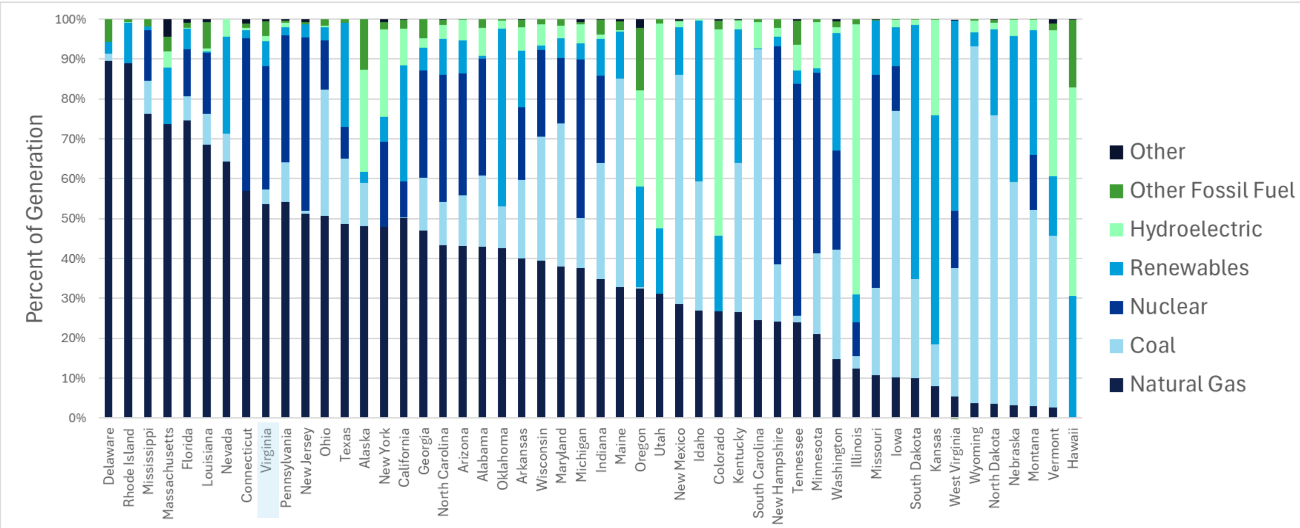
Dominion Energy

Date: June 28, 2024

1 FUEL SOURCE FOR GENERATION

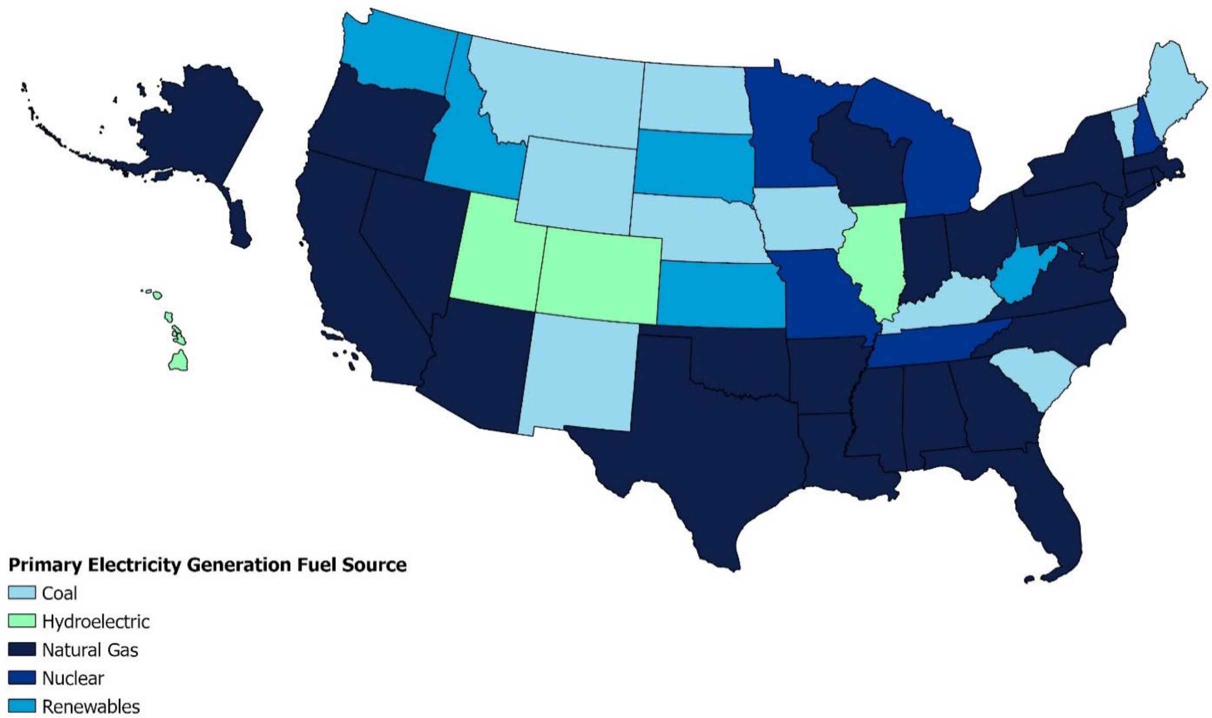
The generation mix of a state can be a significant determinant of its electricity cost. Figure 1 and Figure 2 compare Virginia's generation mix with the rest of the country. Virginia's primary source of electricity generation is natural gas, followed by nuclear. This generation mix is similar to Connecticut, Pennsylvania, and New Jersey. In each state, over 50% of the generation mix is comprised of natural gas and 30% nuclear.

Figure 1. Electricity generation mix, as fraction of total[1]



[1] U.S Energy Information Administration. EIA-923 Power Plant Operations Report. Released 10.26.2023. https://www.eia.gov/electricity/data/state/

Figure 2. Map of primary generation fuel source in each state[2]



2 OTHER METRICS

Variation in electricity bills between states depends in part on the prevalence of electric heating and cooling equipment, cooling and heating loads, and housing size.

Space heating represents a large proportion of many consumers' total energy use. The use of electricity for heating varies widely across regions. Among electrically heated homes, some types of equipment are more efficient than others. Table 1 shows the percentage of different fuels used for home heating in ten Census divisions. Virginia is part of the South Atlantic division that includes Delaware, Maryland, West Virginia, North Carolina, South Carolina, Georgia, Florida, and the District of Columbia. Table 2 shows the mix of different heating equipment by Census division. Table 3 shows the mix of different electric heating equipment by Census division. The South Atlantic division has a large fraction of homes heated by electricity compared to the more northern parts of the country. Of those South Atlantic customers who use electric heat, most use either electric central warm-air furnaces or electric heat pumps. The South Atlantic division also has a larger fraction of homes without heating equipment, as compared to the other regions. Relatively fewer customers in the South Atlantic use central warm-air furnaces for heat, and relatively more use heat pumps when compared to other areas.[3]

[2] U.S. Energy Information Administration. EIA-923 Power Plant Operations Report. Released 10.26.2023. https://www.eia.gov/electricity/data/state/

[3] U.S. Department of Energy, Energy Information Administration. (2020). 2020 Residential Energy Consumption Survey (RECS). Retrieved from Housing characteristics tables, Tables HC6.7 and HC6.8: https://www.eia.gov/consumption/residential/data/2020/, Final release March 2023.

Table 1. Space heating equipment by fuel source by Census division[4]

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain North	Mountain South	Pacific
Natural gas	42%	61%	72%	65%	28%	35%	42%	75%	51%	56%
Electricity	16%	19%	18%	22%	57%	59%	51%	18%	38%	27%
Fuel oil/kerosene	33%	13%	1%	1%	2%	N/A	N/A	N/A	N/A	0%
Propane	6%	4%	7%	10%	3%	5%	2%	4%	3%	2%
Wood	3%	2%	2%	2%	1%	2%	1%	3%	2%	2%
Some other fuel[3]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Do not use heating equipment	N/A	1%	N/A	N/A	10%	N/A	4%	N/A	6%	12%

Table 2. Saturation of heating equipment types by Census division[5]

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Moun-tain North	Moun-tain South	Pacific
Central warm-air furnace	54%	51%	78%	77%	48%	53%	61%	77%	61%	57%
Heat pump	2%	4%	3%	5%	30%	32%	18%	2%	17%	5%
Steam or hot water system	23%	27%	5%	4%	2%	0%	0%	5%	1%	1%
Ductless heat pump (mini-split)	1%	1%	0%	0%	1%	0%	1%	0%	0%	2%
Built-in electric units	9%	9%	6%	5%	4%	4%	5%	7%	3%	9%
Built-in oil or gas room heater	2%	2%	1%	1%	1%	2%	2%	2%	4%	6%
Portable electric heaters	0%	1%	0%	0%	2%	4%	5%	1%	2%	5%
Heating stove burning wood	3%	1%	1%	1%	1%	1%	1%	3%	2%	2%
Some other equipment	5%	2%	2%	3%	1%	1%	2%	2%	0%	1%
Does not use heating equipment	0%	1%	0%	0%	10%	0%	4%	0%	6%	12%

[4] U.S. Department of Energy, Energy Information Administration. (2020). 2020 Residential Energy Consumption Survey (RECS). Retrieved from Housing characteristics tables, Tables HC6.7 and HC6.8: https://www.eia.gov/consumption/residential/data/2020/, Final release March 2023.

[5] U.S. Department of Energy, Energy Information Administration. (2020). 2020 Residential Energy Consumption Survey (RECS). Retrieved from Housing characteristics tables, Tables HC6.7 and HC6.8: https://www.eia.gov/consumption/residential/data/2020/, Final release March 2023.

Table 3. Electric heating equipment mix[6]

		New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Moun-tain North	Moun-tain South	Pacific
Fraction of Homes Heated by Electricity		15%	19%	18%	22%	57%	58%	51%	18%	38%	27%
Fraction Electric-Heated Homes Using:	**Central warm-air furnace**	15%	17%	36%	43%	34%	30%	40%	43%	36%	23%
	Heat pump	11%	22%	19%	24%	53%	55%	36%	9%	45%	18%
	Ductless heat pump (mini-split)	9%	6%	N/A	N/A	2%	N/A	1%	N/A	N/A	6%
	Built-in electric units	55%	45%	36%	23%	7%	7%	10%	39%	9%	33%
	Portable electric heaters	N/A	6%	N/A	N/A	4%	6%	10%	5%	6%	19%

Climate is also a key driver of customers' electricity bills. Heating degree days ("HDD") and cooling degree days ("CDD") are often used as proxies for cooling and heating load. It also measures how much the daily temperature diverges from a base temperature (below 65° Fahrenheit for heating and above the 65° Fahrenheit for cooling). Virginia's annual cooling and heating degree days in 2022 were near the US average. In 2022, Virginia had 1,638 CDD[7] compared to the national average of 1,556 CDD[8] and 3,567 HDD[9] compared to the national average of 4,245 HDD.[10]

However, the number of HDD and CDD vary widely across US regions. See Figure 3 and Figure 4. We added Virginia's 2022 CDD and HDD to the maps for comparison.

[6] U.S. Department of Energy, Energy Information Administration. (2020). 2020 Residential Energy Consumption Survey (RECS). Retrieved from Housing characteristics tables, Tables HC6.7 and HC6.8: https://www.eia.gov/consumption/residential/data/2020/, Final release March 2023.

[7] Energy Star Portfolio Manager. Degree Days Calculator. https://portfoliomanager.energystar.gov/pm/degreeDaysCalculator

[8] U.S. Energy Information Administration. Monthly Energy Review. https://www.eia.gov/totalenergy/data/monthly/

[9] Energy Star Portfolio Manager. Degree Days Calculator. https://portfoliomanager.energystar.gov/pm/degreeDaysCalculator

[10] U.S. Energy Information Administration. Monthly Energy Review. https://www.eia.gov/totalenergy/data/monthly/

Figure 3. Cooling degree days by Census division in 2022

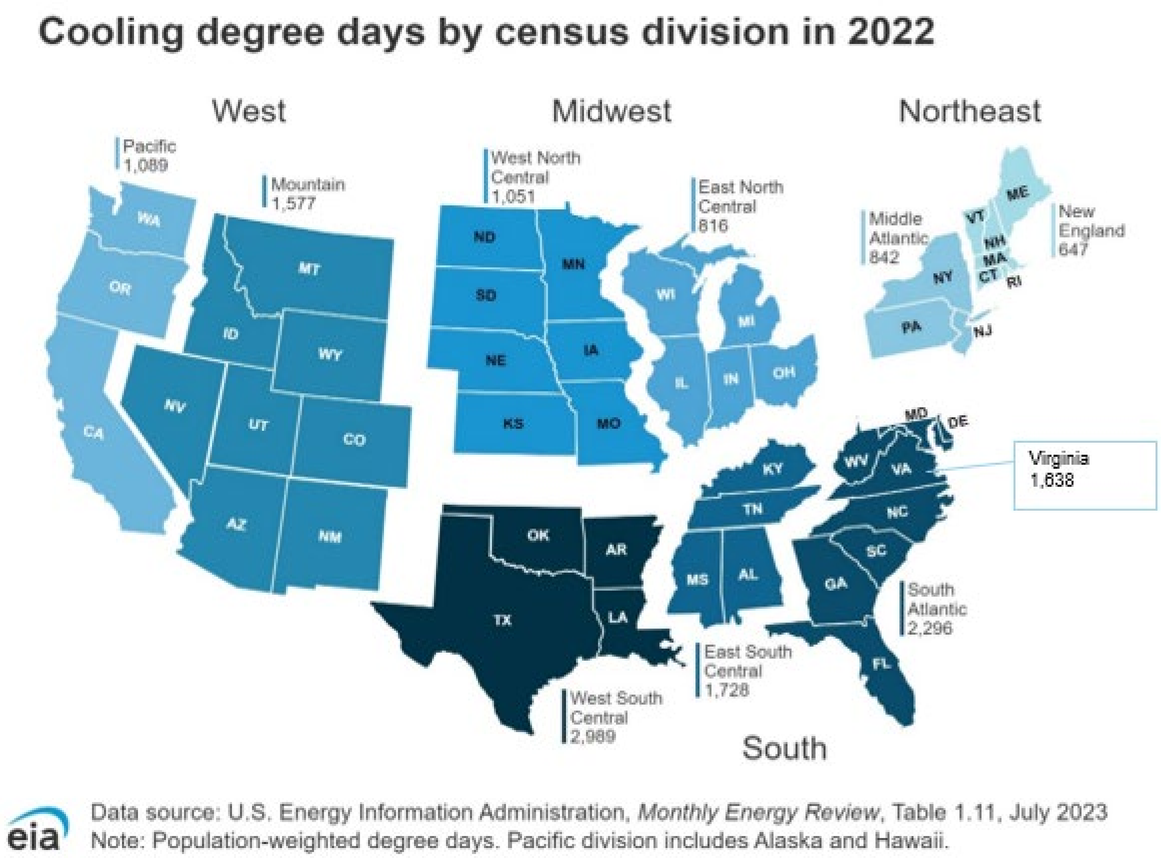
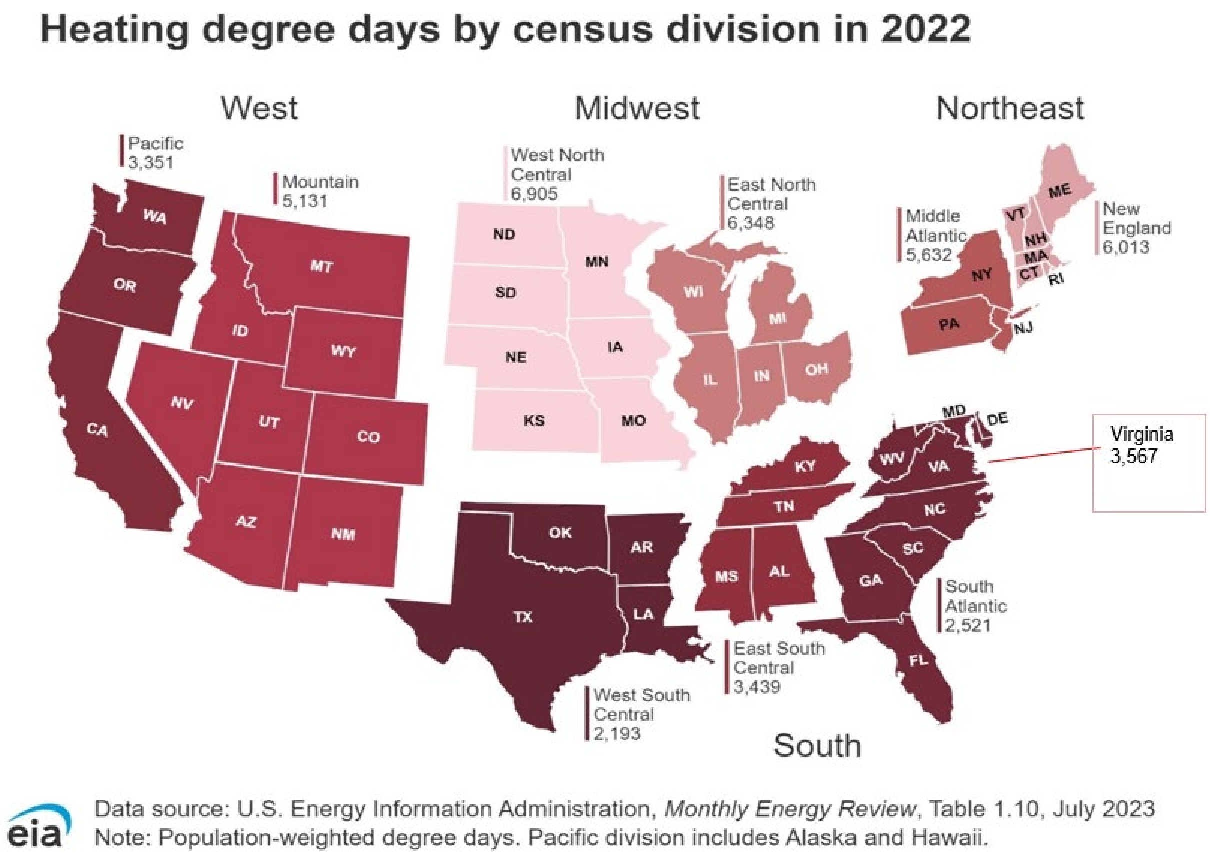


Figure 4. heating degree days by Census division in 2022 [11]



[11] U.S. Department of Energy, Energy Information Administration (EIA). (n.d.). Units and calculators explained. Retrieved from Degree days: https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php

Housing size also affects electricity bills – larger houses require more energy to cool, heat, light, etc. Table 4 shows how housing average square footage varies across the U.S. The South Atlantic division's average home size falls generally in the middle of other census divisions. The South Atlantic heats fewer square feet/house and cools more square feet/house in comparison to most other parts of the country.[12]

Table 4. Average home size[13]

	Average Square Footage per Housing Unit		
	Total	**Heated**	**Cooled**
All homes	1,818	1,614	1,335
New England	1,930	1,645	839
Middle Atlantic	1,789	1,584	1,062
East North Central	2,001	1,851	1,520
West North Central	2,017	1,891	1,621
South Atlantic	1,824	1,558	1,546
East South Central	1,878	1,673	1,523
West South Central	1,739	1,539	1,462
Mountain North	2,015	1,938	1,441
Mountain South	1,681	1,533	1,442
Pacific	1,551	1,313	899

[12] U.S. Department of Energy, Energy Information Administration (EIA). (2020). Residential Energy Consumption Survey (RECS). Retrieved from Square footage (housing unit size), Table HC10.9: https://www.eia.gov/consumption/residential/data/2020/. Release date: March 2023.

[13] U.S. Department of Energy, Energy Information Administration (EIA). (2020). Residential Energy Consumption Survey (RECS). Retrieved from Square footage (housing unit size), Table HC10.9: https://www.eia.gov/consumption/residential/data/2020/. Release date: March 2023.

About DNV

DNV is a global quality assurance and risk management company. Driven by our purpose of safeguarding life, property and the environment, we enable our customers to advance the safety and sustainability of their business. We provide classification, technical assurance, software and independent expert advisory services to the maritime, oil & gas, power and renewables industries. We also provide certification, supply chain and data management services to customers across a wide range of industries. Operating in more than 100 countries, our experts are dedicated to helping customers make the world safer, smarter and greener.

Appendix 3K-1: Levelized Cost Comparison

Levelized cost of energy ("LCOE") is a high-level metric that calculates present value of an energy resource's total lifetime net costs per megawatt-hour ("MWh") of the resource's total estimated lifetime energy output. These costs include fuel and emissions costs, variable and fixed operation and maintenance costs, overnight construction costs, along with applicable cost offsets for renewable technologies, such as renewable energy credits ("RECs") and investment tax credits ("ITCs") or production tax credits ("PTCs").

This appendix compares the LCOE of different resources—both supply- and demand-side—that either currently exist within the Company's available resources or that were screened by the Company for potential inclusion in resource portfolios. The model results show the present value of average lifetime cost per MWh for each modeled resource.

The LCOE values included in this table incorporate the ICF forecast for fuel prices that incorporates the new EPA environmental rules.

The assessment of alternative resource types and the busbar screening process provides a simplified foundation in selecting resources for further analysis. It relies on an average of all the cost data of a resource over its lifetime and should be considered as only one among several complementary methodologies used for selecting resources for inclusion in resource portfolios. Further, as noted within the 2024 IRP, the Company does not use levelized costs to screen DSM programs. DSM programs produce benefits in the form of avoided supply-side capacity and energy costs (*i.e.*, benefits of the DSM programs are reductions in capacity and energy costs and therefore are benefits in that they are reducing the amount of energy and capacity that would otherwise be needed) that are netted against DSM program costs and incentives.

Appendix 3K-1: Comparison of per MWh Costs of Selected Resources

Comparison of per MWh Costs of Selected Resources	COD*	Capacity Factor	Cost ($/MWh) no RECs	Cost ($/MWh) with RECs
Non-Residential Multifamily Program	2024	N/A	$2	N/A
Non-Res Building Optimization	2024	N/A	$10	N/A
Residential Virtual Audit Program	2024	N/A	$15	N/A
Non-Res Building Automation Program	2024	N/A	$19	N/A
Non-Residential Lighting & Controls (Ext of Phase VII CLT3)	2024	N/A	$19	N/A
Non-Residential New Construction	2024	N/A	$23	N/A
Non-Residential Custom	2024	N/A	$29	N/A
Residential Efficient Products Marketplace Program (Extension)	2024	N/A	$32	N/A
Non Res Data Center and Server Rooms	2024	N/A	$35	N/A
Residential Enhanced Home Retrofit	2024	N/A	$36	N/A
Voltage Optimization	2024	N/A	$37	N/A
Residential Customer Engagement Program (Extension)	2024	N/A	$37	N/A
Non-Residential Health Care	2024	N/A	$41	N/A
Non-Residential Prescriptive Bundle	2024	N/A	$41	N/A
Non-Residential Hotel and Lodging	2024	N/A	$41	N/A
Residential Water Savings (EE) Program	2024	N/A	$46	N/A
Non-Residential EE Products	2024	N/A	$47	N/A
Residential New Construction	2024	N/A	$50	N/A
Non-Res Engagement Program	2024	N/A	$58	N/A
Non-Residential New Construction	2024	N/A	$59	N/A
Small Business Behavioral	2024	N/A	$67	N/A
Solar - PPA	2027	N/A	$67	N/A
Residential Smart Thermostat (EE)	2024	N/A	$79	N/A
Wind - Off-Shore 1	2027	42%	$79	$108
Solar - Tracker	2027	24%	$80	$109
Residential New Construction	2024	N/A	$84	N/A
Non-Residential Small Business Improvement Enhanced Program	2024	N/A	$99	N/A
Wind - Off-Shore 2	2027	$0	$103	$132
Wind - On-Shore	2027	$0	$110	$141
Residential Smart Thermostat (EE)	2024	N/A	$111	N/A
Residential Smart Home Program	2024	N/A	$114	N/A
Residential Multifamily Program	2024	N/A	$121	N/A
3x1 CC Greenfield	2027	40%	$123	N/A
2X Advanced CT	2027	40%	$135	N/A
Storage - PPA	2027	N/A	$138	N/A
2x1 CC Greenfield	2027	40%	$142	N/A
Nuclear SMR	2027	92%	$158	N/A
4X Aero CT	2027	50%	$165	N/A
Residential EE Kits	2024	N/A	$176	N/A
4X CT	2027	20%	$177	N/A
Battery Generic 8H (30 MW)	2027	33%	$191	N/A
1x1 CC Greenfield	2027	40%	$200	N/A
2X Aero CT	2027	50%	$210	N/A
Distributed Solar (3 MW)	2027	24%	$219	$248
Battery Generic 4H (30 MW)	2027	17%	$223	N/A
Residential Smart Thermostat Program (Behavioral)	2024	N/A	$292	N/A
Non-Residential Agricultural	2024	N/A	$300	N/A
Residential Electric Vehicle (EE)	2024	N/A	$368	N/A
Pump Hydro Storage (300 MW)	2027	15%	$718	N/A
Residential Manufactured Housing Program	2024	N/A	$864	N/A
Residential IAQ Home Energy Report	2024	N/A	$1,055	N/A
Residential Income and Age Qualifying Bundle	2024	N/A	$1,487	N/A
Commercial Distributed Generation Program	2024	N/A	$1,560	N/A
Residential Peak Time Rebate	2024	N/A	$2,067	N/A
Low-Income HVAC HB 2789 (Solar Component)	2024	N/A	$3,006	N/A
Non-Residential Income and Age Qualifying Bundle	2024	N/A	$3,583	N/A
Residential Smart Thermostat (DR)	2024	N/A	$4,201	N/A
Residential Water Savings (DR) Program	2024	N/A	$18,043	N/A
Residential Electric Vehicle Peak Shaving (DR)	2024	N/A	Inf	N/A
Residential Smart Thermostat (DR)	2024	N/A	Inf	N/A
Residential Telematics Vehicle Charger Pilot (DR)	2024	N/A	Inf	N/A

Notes
Includes 30% ITC for Distributed Solar and Storage
Storage PPA Price is $/kW

Appendix 3K-2: Tabular Results of Busbar

	Capacity Factor (%)										
$/kW-Year	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
3x1 CC Greenfield	$ 265	$ 305	$ 346	$ 387	$ 427	$ 468	$ 509	$ 549	$ 590	$ 630	$ 671
2x1 CC Greenfield	$ 327	$ 368	$ 409	$ 450	$ 490	$ 531	$ 572	$ 613	$ 654	$ 694	$ 735
1x1 CC Greenfield	$ 524	$ 565	$ 606	$ 647	$ 688	$ 729	$ 770	$ 811	$ 852	$ 893	$ 934
4X CT	$ 169	$ 237	$ 306	$ 374	$ 443	$ 512	$ 580	$ 649	$ 717	$ 786	$ 854
2X Advanced CT	$ 192	$ 261	$ 330	$ 399	$ 468	$ 537	$ 606	$ 674	$ 743	$ 812	$ 881
4X Aero CT	$ 392	$ 457	$ 523	$ 588	$ 654	$ 720	$ 785	$ 851	$ 916	$ 982	$ 1,047
2X Aero CT	$ 589	$ 654	$ 720	$ 786	$ 851	$ 917	$ 982	$ 1,048	$ 1,113	$ 1,179	$ 1,245
Nuclear SMR	$ 1,277	$ 1,277	$ 1,277	$ 1,277	$ 1,277	$ 1,277	$ 1,277	$ 1,277	$ 1,277	$ 1,277	$ 1,277
Solar - Tracker	$ 264	$ 223	$ 182	$ 141	$ 100	$ 59	$ 17	$ (24)	$ (65)	$ (106)	$ (147)
Distributed Solar (3 MW)	$ 520	$ 494	$ 468	$ 442	$ 416	$ 390	$ 364	$ 338	$ 312	$ 286	$ 260
Wind - On-Shore	$ 345	$ 303	$ 261	$ 219	$ 176	$ 134	$ 92	$ 50	$ 7	$ (35)	$ (77)
Wind - Off-Shore 1	$ 469	$ 426	$ 384	$ 341	$ 298	$ 256	$ 213	$ 171	$ 128	$ 85	$ 43
Wind - Off-Shore 2	$ 557	$ 515	$ 472	$ 429	$ 387	$ 344	$ 302	$ 259	$ 216	$ 174	$ 131
Battery Generic 4H (30 MW)	$ 307	$ 318	$ 329	$ 340	$ 351	$ 362	$ 374	$ 385	$ 396	$ 407	$ 418
Battery Generic 8H (30 MW)	$ 522	$ 533	$ 544	$ 555	$ 566	$ 577	$ 588	$ 599	$ 611	$ 622	$ 633
Pump Hydro Storage (300 MW	$ 966	$ 951	$ 936	$ 921	$ 906	$ 891	$ 876	$ 861	$ 846	$ 831	$ 816

Notes:

(1) Offshore Wind has a capacity factor of 42%.

(2) Onshore Wind has a capacity factor of 37%.

(3) Solar has a capacity factor of 25%.

(4) Distributed solar has a capacity factor of 24%.

(5) Batteries and Pump Storage have a capacity factor of 15%.

Appendix 3K-3: Busbar Assumptions

Nominal $	Heat Rate	Variable Cost (1)	Fixed Cost (2)		Book Life	2024 Real $ (3)
	MMBtu/MWh	$/MWh	$/kW-Year	$/MWh	Years	$/kW
3x1 CC Greenfield	6.14	$46	$265	$76	36	$1,523
2x1 CC Greenfield	6.13	$47	$327	$93	36	$1,667
1x1 CC Greenfield	6.12	$47	$524	$149	36	$2,000
4X CT	10.37	$78	$169	$128	36	$1,562
2X Advanced CT	10.37	$79	$192	$146	20	$1,781
4X Aero CT	9.91	$75	$392	$298	36	$3,977
2X Aero CT	9.91	$75	$589	$448	36	$5,479
Nuclear SMR	$12	$0	$1,277	$158	60	$11,147
Solar - Tracker	-	-$47	$264	$124	35	$2,278
Distributed Solar (3 MW)	-	-$30	$520	$243	30	$4,675
Wind - On-Shore	-	-$48	$345	$150	25	$2,400
Wind - Off-Shore 1	-	-$49	$469	$127	30	$4,497
Wind - Off-Shore 2	-	-$49	$557	$151	30	$5,164
Battery Generic 4H (30 MW)	-	$13	$307	$210	20	$2,782
Battery Generic 8H (30 MW)	-	$13	$522	$179	20	$4,666
Pump Hydro Storage (300 MW)	-	-$17	$966	$735	50	$9,667

Notes:

(1) Variable costs for solar and wind includes RECs value.

(2) Fixed costs include capital expenditures, fixed O&M, federal tax credits, and gas firm transmission expenses.

(3) Values in this column represent overnight installed cost.

Appendix 3L: Distribution

The Company's obligation to provide safe and reliable service continues as the Company transitions toward a cleaner energy future. This appendix provides an overview of the distribution planning process and current initiatives related to the distribution grid.

I. Distribution Planning

In 2019, the Company presented a white paper that provided a conceptual first look at its transition toward integrated distribution planning ("IDP"). The Company defines IDP as a consolidated process to address the capacity, performance, reliability, resilience, and distributed energy resources ("DER") integration needs of the distribution grid. The white paper noted that the evolution to IDP requires changes related to people, technologies, and processes. Throughout, trained professionals are vital to leverage the technologies and optimize the processes. Technologies and secure communications that provide real-time visibility into the grid to the customer level are foundational to enable IDP. Processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analytical tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on the distribution grid. These concepts remain true today.

The Company has made notable successes in the evolution toward IDP since 2019, including successes related to people, such as the centralization of its organizational structure such that one team focuses on all distribution-related modeling and data analysis activities for load and reliability driven investments; expansion of internal IDP focused capabilities; technologies, primarily through development and implementation of Grid Transformation Plan investments; and processes, such as the development of an initial forecast of DERs by feeder and publications of hosting capacity maps for different types of DERs.

In 2021, the Company noted its continued work on a roadmap for IDP that adds tangible goals and timeframes to IDP maturity and stated its intention to present that roadmap in 2023. The Company submitted the IDP roadmap in Case No. PUR-2023-00051.

II. Existing Distribution Facilities

The Company's existing distribution grid in Virginia consists of more than 54,000 miles of overhead and underground cable, and over 400 substations operating at distribution voltage levels ranging from 4 kV to 46 kV. The distribution grid utilizes a variety of devices for functions, from voltage control to power flow management, and relies on multiple operating systems for various functions, from customer billing to outage management.

Appendix B of the executive summary of the Grid Transformation Plan filed in Case No. PUR-2023-00051 provided a detailed description of the Company's existing distribution grid.

III. Grid Transformation Plan

The Grid Transformation Plan is the Company's comprehensive plan to transform its electric distribution grid to facilitate the integration of DERs, to enhance grid reliability and security, and to improve the customer experience.

In Phases I and II of the Grid Transformation Plan, which generally covers investments in grid transformation projects between 2019 and 2023, the Company pursued projects that are foundational to the vital objectives of grid transformation. From these initial investments the Company has seen notable successes that have a direct and positive effect on its customers. The Company has deployed advanced metering infrastructure ("AMI") to nearly all of its customers in Virginia, enabling these customers to take control of their energy usage with the granular data that smart meters provide. The Company's new customer information platform ("CIP") went live in April 2023, enabling the systems needed to modernize the customer relationship. The Company has enhanced grid reliability through multiple grid transformation projects, providing a direct benefit to customers and improving the availability of the grid for DERs. And the Company has facilitated the integration of DERs, for example, through the launch of three hosting capacity tools that provide guidance to customers and developers about siting clean energy installations and EV charging infrastructure, and through its rebate program for the installation of smart charging infrastructure for EVs.

In Phase III, which was filed in Case No. PUR-2023-00051, the Company sought approval to continue its work on approved projects and approval of two new projects. Specifically, the Company sought to complete the deployment of two foundational GT Plan investments—AMI and the CIP. The Company also sought to continue its three grid infrastructure projects—mainfeeder hardening, targeted corridor improvement, and voltage island mitigation—along with three of its grid technologies projects—a DER management system, voltage optimization enablement, and substation technology deployment. Together, these investments will continue to enhance grid reliability and to facilitate the integration of DERs. Additionally, the Company sought to continue investing in enhanced telecommunications, physical substation security, cyber security, and customer education as needed to support other projects. Finally, the Company proposed a new outage management system to accommodate the complexity of the modern distribution grid, and a process to evaluate energy storage systems as non-wires alternatives to traditional distribution investments. The SCC approved the continuations of previously approved projects and the two new projects by Final Order dated September 18, 2023.

Overall, the Grid Transformation Plan represents the optimal package to facilitate the integration of DERs while maintaining and enhancing reliable and secure electric service. Achieving these objections is vital to the clean energy goals discussed in this 2024 Plan.

IV. Strategic Undergrounding Program

The Company is continuing the Strategic Undergrounding Program ("SUP"), which is in its seventh phase. Originally conceived as a 4,000-mile program in 2014, the Company has converted approximately 2,261 miles of outage-prone overhead tap lines as of August 30, 2024. A legislative sunset clause currently requires the SUP to conclude in 2028. More details on the SUP are available in the Company's annual filings with the SCC, which specify the miles of tap lines converted and their locations, tap line reliability performance pre- and post-conversion, and system-wide reliability statistics.

Both local and system-wide benefits are key aspects of the SUP. Specifically, the SUP was designed to shorten restoration times in severe weather events by reducing the number of labor-intensive work locations associated with outage-prone single-phase overhead tap lines, especially those behind homes with significant tree coverage. By converting those tap lines to underground, directly served customers will either see a shorter outage or no outage. Perhaps more importantly, this enables crew redeployment to other outage locations, allowing a faster recovery after severe weather events for the benefit of all customers. The SUP remains the most effective and comprehensive solution for eliminating work associated with systemic tap line outages and is complemented by the mainfeeder hardening program in the Grid Transformation Plan, which targets mainfeeders serving customers with the poorest reliability.

V. Battery Storage Pilot Program

Specific to the distribution grid, the Company is currently studying the use of battery energy storage systems on its distribution grid through the pilot program established by the GTSA. Two Battery Energy Storage Systems ("BESS") came online on the distribution grid in 2022:

- BESS-1, a 2 MW/4 MWh AC lithium-ion BESS, that is studying the prevention of solar backfeeding onto the transmission grid at a substation located in New Kent County; and
- BESS-2, a 2 MW/4 MWh AC lithium-ion BESS, that is studying batteries as a non-wires alternative to reduce transformer loading at a substation located in Hanover County.

The Company also deployed a lithium-ion BESS at its Scott Solar Facility to study solar plus storage.

The Company filed its first annual report on the pilot program with the SCC on March 31, 2023, in Case No. PUR-2019-00124, including lessons learned from constructing these pilot BESS. As to the two distribution BESS, throughout 2022, BESS-1 showed excellent progress towards meeting its objectives, with initial data analysis indicating that both transformer load tap changer operations and total backfeed have been reduced. Initial results are also very promising for BESS-2, with 18% percent of the exported energy occurring during the two highest load hours of each day on the associated transformer and 39% occurring during the four highest load hours of each day. Three other pilot projects, most recently approved, comprised of three non-lithium batteries and one lithium-ion battery total 12.34 megawatts under development. All projects under development will reach commercialization by the end of 2027. The Company continues to evaluate additional opportunities for the remaining megawatts of the pilot program aimed at understanding the ability of storage to provide reliability and resiliency for the Company's customers.

These BESS provide the Company the opportunity to study important statutory objectives, and the information and experience gained from each will provide valuable insight and experience toward deployment of BESS in the future. The Company continues to explore additional unique energy storage use cases for future consideration within the battery storage pilot program.

VI. Electric School Bus Program

The Company's Electric School Bus Program combines the Company's efforts with energy storage technologies and electric vehicles, while at the same time assisting customers' decarbonization efforts. In addition to reducing the carbon footprint of the Commonwealth and improving air quality for students, the batteries in electric school buses can be used to increase the stability and reliability of the grid and can help to facilitate the integration of renewable energy resources such as solar and wind onto the distribution grid. In Phase I of this Program, the Company supported 15 localities and 50 electric school buses. The Company is also supporting localities that receive Virginia Department of Environmental Quality Clean School Bus grants, American Recovery Act Electric School Bus rebates, and EPA Clean School Bus rebates.

The Electric School Bus Program, coupled with a modernized grid, will allow the Company to gain understanding and knowledge regarding strategic deployment of EVs as resources for the benefit of customers and the grid. Since August 2022, Dominion Energy, in partnership with Thomas Built Buses, Sonny Merryman Inc., Borg Warner, EPRI, and Synop, have successfully demonstrated multiple V2G discharge events on the Dominion Energy Virginia distribution system, including the largest test to date in July 2024, with over 6 megawatt-hours ("MWh") of energy discharged across 7 electric school bus sites.

Phase 1 of the Electric School Bus Program was implemented in 2019. Out of 34 applicants within Dominion Energy Virginia's service territory, 15 localities were chosen to receive the first 50 buses. Between 2021 through 2023, in collaboration with the Virginia Department of Environmental Quality ("DEQ"), an additional 68 electric school buses were integrated into the program across 14 new and existing locality partners. The DEQ program utilized funds derived from the VW settlement, with Dominion Energy providing all necessary charging infrastructure. Launched in 2022 with funding from the Bipartisan Infrastructure Law, the EPA Clean School Bus Program is providing $5 billion dollars nationally over five years to replace existing school buses with zero-emission models. Dominion Energy aims to provide charging support to school districts awarded through the EPA Program and explore further funding opportunities. To date, Dominion Energy is supporting 26 different localities in Virginia and 184 electric school buses that have recorded more than 2.5 million miles traveled.

VII. Rural Broadband Program

Originally a pilot program, the rural broadband program is now a permanent, innovative approach to install middle-mile fiber to help achieve universal broadband access across the Commonwealth. The Company is leveraging the telecommunications infrastructure deployed as part of the Grid Transformation Plan by using a portion of the fiber capacity to meet its own distribution grid needs and then leasing another portion to an internet service provider. By utilizing the telecommunication infrastructure for both operational needs and broadband access, the Company can reduce broadband deployment costs for internet service providers, enabling these providers to deliver high-speed internet access to unserved residences and business.

The Company currently has agreements with over 30 counties to reach unserved areas through partnerships with five internet service providers, including All Points Broadband, RURALBAND, EMPOWER Broadband, and Firefly Fiber Broadband. The middle-mile project in Surry County is complete and RURALBAND is actively serving Surry County residents. Projects are underway (either in development or under construction) in Botetourt, Stafford, Westmoreland, Richmond, Northumberland, King George, Lancaster, King William, Louisa, Appomattox, Augusta, Loudoun, Culpeper, Fauquier, Rockingham, Hanover, Middlesex, Sussex, Dinwiddie, Albemarle, Buckingham, Cumberland, Fluvanna, Goochland, Nelson, Powhatan, Brunswick, Halifax, and Mecklenburg counties.

As of September 26, 2024, approximately 1,400 miles of fiber have been installed as a part of the Rural Broadband Program with approximately 1,300 additional miles planned for the remainder of 2024 and beyond.

Appendix 3M: Grid Transformation Plan

Table of Contents

Introduction

Headquartered in Richmond, Virginia, Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") currently serves approximately 2.7 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company owns approximately 59,700 miles of distribution lines at voltages ranging from 4 kilovolts ("kV") to 46 kV in Virginia and North Carolina.

Dominion Energy Virginia first presented its plan to transform its distribution grid ("Grid Transformation Plan," "GT Plan," or "Plan") in 2018. Since then, the Company has engaged in an iterative process to refine its Grid Transformation Plan, incorporating feedback from the State Corporation Commission of Virginia (the "Commission"), Commission Staff, and other stakeholders, to devise the best strategy to meet the overarching goals of grid transformation—facilitating the integration of distributed energy resources ("DERs") and maintaining system reliability and security.

"Phase I" of the Grid Transformation Plan focused on grid transformation projects in the years 2019, 2020, and 2021.[1] "Phase II" of the GT Plan focuses on grid transformation projects in the years 2022 and 2023. "Phase III" of the Plan now focuses on grid transformation projects in the years 2024, 2025, and 2026. The Company anticipates additional future phases of the Grid Transformation Plan to continue the objectives and efforts of grid transformation.

The Company presented its first executive summary of the Grid Transformation Plan in 2019, and presented an updated executive summary in 2021. This 2023 version updates the document to reflect industry developments supporting grid transformation, refinements to the Grid Transformation Plan, and the Company's progress with grid transformation efforts to date.

[1] The Company has referred to "Phase IA" as projects approved by the Commission in Case No. PUR-2018-00100 and "Phase IB" as projects approved by the Commission in Case No. PUR-2019-00154.

Executive Summary

Fundamental changes in the energy industry have prompted the need for utilities across the country to modernize their distribution grids. With the passage of the Grid Transformation and Security Act of 2018 ("GTSA"), the Commonwealth of Virginia recognized this need, declaring electric distribution grid transformation to be in the public interest and mandating that utilities file a plan for grid transformation. The GTSA set forth two objectives for grid transformation: (i) facilitating the integration of DERs and (ii) enhancing grid reliability and security.

In response to this need, Dominion Energy Virginia prepared a comprehensive plan to transform its distribution grid to meet the changing landscape of the energy industry while continuing to provide the reliable service that its customers expect and deserve.

In Phases I and II of the Grid Transformation Plan, the Company pursued projects that are foundational to the vital objectives of grid transformation. From these initial investments the Company has seen notable successes that have a direct and positive effect on its customers. The Company has deployed advanced metering infrastructure ("AMI") to nearly three-quarters of its customers in Virginia, enabling these customers to take control of their energy usage with the granular data that smart meters provide. And the Company's new customer information platform ("CIP") is scheduled to go live in the second quarter of 2023, enabling the systems needed to modernize the customer relationship. The Company has enhanced grid reliability through multiple grid transformation projects, providing a direct benefit to customers and improving the availability of the grid for DERs. For example, customers served by the first seven feeders targeted through the Company's mainfeeder hardening program saw on average a 50% improvement in performance on mainline sections, avoiding on average over 140,000 minutes interrupted monthly for each feeder. And the Company has facilitated the integration of DERs through, for example, the launch of two hosting capacity tools that provide guidance to customers and developers about siting clean energy installations and through its rebate program for the installation of smart charging infrastructure for electric vehicles ("EVs").

The passage of time has validated the need for the Grid Transformation Plan. In previous phases the Company discussed the policy and market developments that would accelerate the shift toward DER, including the issuance of FERC Order 2022 regarding DER aggregation for participation in regional markets and the passage of the Virginia Clean Economy Act of 2020 ("VCEA") calling for the development of significant amounts of distributed solar and energy storage and expanding opportunities for net metering in the Commonwealth. The Company has seen this shift, with an 86% increase in executed interconnection agreements for solar interconnections through the Company's queue between year-end 2021 and year-end 2022, a 59% increase in net energy metering customers, and an approximately 50% increase in customers with EVs in the Company's service territory. In addition, major weather events and physical attacks continue to show that more work is needed to achieve the objectives of grid transformation.

In Phase III, the Company seeks to continue its work on approved projects toward the objectives of grid transformation based on the same need that has been shown in prior proceedings. Specifically, the Company seeks to complete the deployment of two foundational GT Plan investments—AMI and the CIP. The Company also seeks to continue its three grid infrastructure projects approved by the Commission in prior phases—mainfeeder hardening, targeted corridor improvement, and voltage island mitigation—along with three of its previously approved grid technologies projects—a DER management system ("DERMS"), voltage optimization enablement, and substation technology deployment. Together, these investments will continue to enhance grid reliability and to facilitate the integration of DERs. Finally, the Company seeks to continue investing in enhanced telecommunications and physical substation security, as well as investments in cyber security and customer education as needed to support other proposed projects.

Phase III also requests approval of two new projects. First, the Company proposes to deploy a new outage management system ("OMS") to replace an outdated operating system that cannot accommodate the complexity that a modern distribution grid requires. The new OMS is also needed to leverage the full benefits of other GT Plan investments, such as AMI, intelligent grid devices, and fault location, isolation, and service restoration ("FLISR") software. Second, the Company seeks approval of a process to evaluate energy storage systems as non-wires alternatives ("NWAs") to traditional distribution investments. This process will enable the Company to gain experience with this integrated distribution planning concept in a manner that will provide useful information as the Company moves forward with NWAs and that may result in the integration of energy storage systems that can dynamically respond to changing grid conditions.

This document provides a guide through the need for grid modernization (Section I), the Company's distribution grid planning process (Section II), and the development of the Grid Transformation Plan (Section III). This document also provides an overview of the Plan itself (Section IV), including the accurate and reasonable cost estimates for each project based on competitive bidding processes and the quantitative and qualitative benefits of the proposed projects. The Grid Transformation Plan represents the optimal package to facilitate the integration of DERs while maintaining and enhancing reliable and secure electric service.

I. Need for a Modern Distribution Grid

Electricity has become a basic need, vital to our economy, public safety, and way of life. Critical services and infrastructure increasingly rely on electricity, including homeland security, medical facilities, public safety agencies, state and local governments, telecommunications, transportation, and water treatment and pump facilities. The transportation industry is actively continuing its shift toward electrification of personal vehicles, fleets, and mass transit. Another vital resource powered by electricity is the internet, which drives commerce and everyday life. As society has grown more dependent on electricity, customers expect highly reliable service. The critical need for reliable electric service became even more acute in 2020, when life for many Americans—including commerce, education, and health—shifted to the home, and the internet, because of the pandemic. While service interruptions have always been an inconvenience, the safe, reliable, and consistent grid connectivity has never been more important than it is today. With policy and climate change initiatives important to the Company and the Commonwealth, electricity should also be increasingly clean.

A. Context for Distribution Grid Transformation

The electric grid was originally designed for the one-way flow of electricity, with electricity moving from large, centralized generators through high-voltage transmission lines to the distribution system. On the distribution system, electricity flowed from the substation to the customer. While originally limited to cities, the electric power grid eventually reached even the most remote areas of the country as a result of the incentives provided in the Rural Electrification Act of 1936 for the installation of distribution systems in isolated rural areas of the United States. A comprehensive description of Dominion Energy Virginia's existing distribution grid is provided as Appendix B.

As reliance on electricity grew, focus shifted to the transmission system as vital to reliability of the electric grid as designed (*i.e.*, the one-way flow of electricity). The Northeast Blackout of 2003 drove new standards and investments into the transmission grid. The North American Electric Reliability Corporation ("NERC") became the national electric reliability organization responsible for the reliability of the transmission system, and instituted mandatory minimum standards to which transmission owners had to plan.

In the current day, focus has now shifted to DERs. The term "DER" encompasses all manner of resources, including solar and wind generation, energy storage, and EVs. As the Department of Energy's Office of Electricity noted in a 2019 report, "[m]any parts of the country are experiencing fundamental changes in customer expectations for distribution grid performance, with a large number of customers utilizing the grid to integrate DER and other new technologies or seeking a platform for market transactions."[2]

The rise of DERs requires a fundamental change to the electric grid. With DERs, electricity is now flowing onto the distribution system from multiple points. The distribution

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[2] Department of Energy's Office of Electricity, MODERN DISTRIBUTION GRID (DSPX) VOLUME I: OBJECTIVE DRIVE FUNCTIONALITY at 16 (Nov. 2019) [hereinafter DOE REPORT], *available at* https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_I_v2_0.pdf.

system that was designed for the one-way flow of electricity must now accommodate the dynamic flow of electricity. In addition, the intermittent nature of some of these resources resulting from weather variability creates power fluctuations not typical of traditional generation resources. Propagated in an arbitrary manner, DERs are independent nodes that can disrupt traditional grid power quality and reliability. But when paired with investments to increase visibility, reliability, and resiliency on and control of the distribution system, the grid can transform DERs into a system resource that can be equitably managed to maximize the value of other available resources, to potentially offset the need for future "traditional" generating assets or grid upgrades, and to maintain reliable service to customers. In addition, because DERs rely on the distribution system to deliver the electricity they produce, a resilient distribution system is vital to maximizing the value of DERs. Day to day outages as well as major weather events not only cause prolonged outages for customers, but also prevent DERs from delivering electricity. The distribution system must be reliable and resilient so that it can operate for DERs like the transmission system operates for large, centralized generators. As the Electric Power Research Institute ("EPRI") has outlined, the distribution grid benefits DER through (i) reliability; (ii) startup power; (iii) voltage quality; (iv) efficiency; and (v) energy transaction.[3]

And throughout, severe weather and man-made events continue as a reality across the country. The value of resiliency investments in response to such events has been demonstrated both by the Company and by peer utilities, enabling timely restoration and economic recovery when damage does occur.

B. Developments Supporting Grid Transformation—2019 to 2021

Between 2019 and 2021, a number of developments occurred that support the need for grid transformation.

At the federal level, FERC issued a final rule in 2020—Order 2222—that allows for aggregation of all manner of DERs for participation in regional markets (*e.g.*, PJM). Specifically, FERC Order 2222 required each regional transmission operator to create models for DERs to aggregate and participate in their wholesale markets on a comparable level with other resources. The order defined DER 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."

In Virginia, the General Assembly accelerated its transition to a cleaner energy future with the passage of the VCEA in 2020. The VCEA called for the development of a significant amounts of DERs, including 1,100 MW of small-scale solar resources that will interconnect to the distribution grid and 2,700 MW of energy storage that may interconnect to the distribution grid. The VCEA required the Commission to adopt regulations related to the deployment of energy storage in the Commonwealth, and required those regulations to include programs and

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[3] American Public Power Association, THE VALUE OF THE GRID (Jul. 2018), *available at* https://www.publicpower.org/system/files/documents/Value%20of%20the%20Grid_1.pdf (citing EPRI, THE INTEGRATED GRID: REALIZING THE FULL VALUE OF CENTRAL AND DISTRIBUTED ENERGY RESOURCES (2014)).

mechanisms to deploy energy storage, specifically including behind-the-meter incentives and non-wires alternatives programs. Many of these programs will necessarily occur at the distribution level. In addition, the VCEA expanded the opportunity for customers to participate in net metering through the installation of renewable energy resources at their distribution-connected premises and set aggressive targets for energy efficiency savings.

Throughout the country, there was support for transportation electrification. The federal administration declared its support for electric vehicles in 2021, announcing additional grant funding opportunities to encourage EV adoption. In Virginia, the General Assembly passed legislation in 2021 that encouraged transportation electrification, including rebates for the purchase of EVs and requirements for manufacturers to offer EVs for sale in Virginia. More EVs means more EV charging infrastructure connected to the distribution grid.

Aside from these developments in Virginia, advancements in other states and industry groups show that Virginia is not alone in its transition to modern distribution grids. As an example, in early 2019, the National Association of Regulatory Utility Commissioners ("NARUC") and the National Association of State Energy Officials ("NASEO") convened a task force to address the need to reimagine electricity system planning processes in a world of DERs. In its February 2021 final report, the task force leadership reemphasized the continuing relevance of the drivers that initiated its efforts: (i) improve grid reliability and resilience; (ii) optimize use of distributed and existing energy resources; (iii) avoid unnecessary costs to ratepayers; (iv) support state policy priorities; and (v) increase the transparency of grid-related investment decisions.[4]

C. Developments Supporting Grid Transformation—2021 to 2023

Additional developments supporting grid transformation efforts have occurred since the Company filed its 2021 GT Plan Document.

At the federal level, the Infrastructure Investment and Jobs Act of 2021 (the "IIJA") provides several competitive funding opportunities to incentivize energy infrastructure investment, including in the areas of grid modernization, reliability, resiliency, and flexibility. The Company intends to actively participate in as many opportunities that align with the Company's operations while providing overall net benefits to its customers. In addition, the Inflation Reduction Act of 2022 extends and adds tax incentives to promote clean energy, including incentives related to DERs.

In Virginia, Governor Youngkin, on behalf of the Virginia Department of Energy, presented a new Virginia Energy Plan in 2022 that recognized reliability as the top guiding principle, stating: "The lights must always turn on. From supporting internet connections for students to cooling homes in the summer, to powering critical data centers and state-of-the-art

[4] NARUC-NASEO Task Force on Comprehensive Electricity Planning, BLUEPRINT FOR STATE ACTION at 3 (Feb. 2021), *available at* https://pubs.naruc.org/pub/14F19AC8-155D-0A36-311F-4002BC140969.

manufacturing facilities, and to keeping a senior citizen warm in the winter, the reliability of our electricity grid is critical."[5]

Throughout the country, major events continue to show the vulnerability of the grid, including severe weather events and man-made threats to critical grid infrastructure. These events illustrate that utilities are a target. A secure, reliable, and nimble grid is necessary to respond to the events and technologies in the modern world.

D. DER Growth

The Company has seen continuous growth in DERs over the past several years. For example, for larger-scale DERs as of December 31, 2022, there are 68 interconnection requests for solar generation sites totaling 624 MW with executed interconnection agreements that are in the construction process, and 576 requests totaling 3,049 MW that are at some level of evaluation under the state interconnection process. This compares to a total of 51 utility-scale solar generation sites totaling 529 MW connected to the Company's distribution system in Virginia as of year-end 2022.

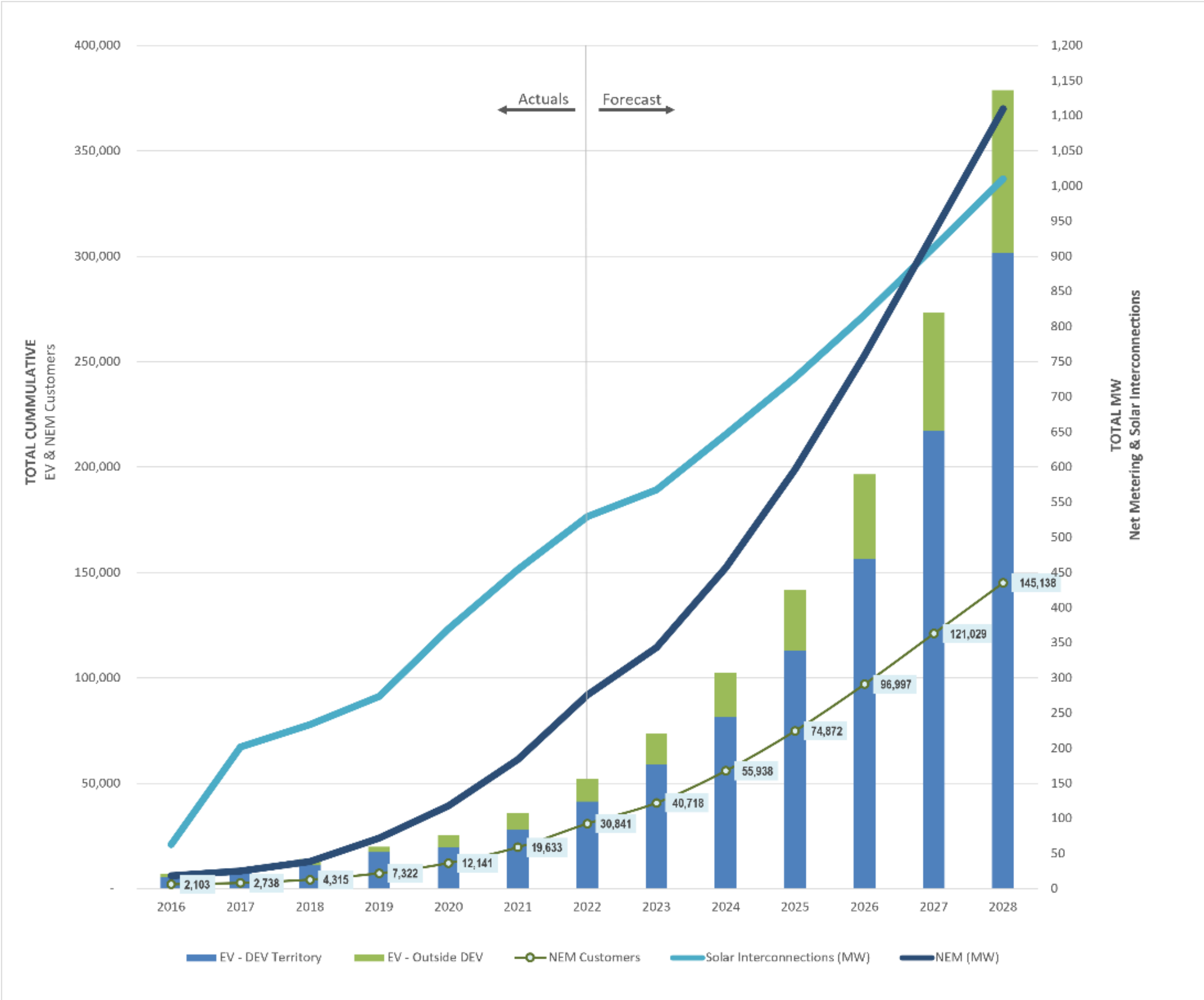
Looking at smaller DERs, the Company has seen the number of net energy metering ("NEM") customers grow from approximately 2,100 in 2016 to over 30,800 in 2022, an approximately 1400% increase in that six-year period. In 2022 alone, the Company facilitated interconnection of over 11,000 unique net metering installations. As of December 31, 2022, the Company supports over 30,800 net metering customers with a collective capacity over 275 MW at the system level. Similar growth trends can be seen related to EVs, with greater than 50,000 customers in the Company's service territory having switched to electric.

The Company expects this DER growth to continue with the market developments and supportive public policies discussed in Section I.B and I.C. Based on current forecasts, the Company expects both solar interconnections on the distribution grid and net energy metering installations to total more than 2,100 MW, and projects over 300,000 customers switching to EVs.

Figure 1 shows the actual growth in DERs between 2016 and 2022, as well as the forecasted growth in DERs for the next five years.

[5] Virginia Department of Energy, 2022 VIRGINIA ENERGY PLAN, *available at* https://energy.virginia.gov/energy-efficiency/documents/2022_Virginia_Energy_Plan.pdf.

Figure 1: DER Growth in Dominion Energy Virginia Service Territory



Propagated in an arbitrary manner, DERs can disrupt grid power quality and reliability. Yet the investments outlined in the Grid Transformation Plan combined with the evolution of the Company's integrated distribution planning process seek to ensure that any potential adverse impacts will not occur. Specifically, the completed and planned GT Plan investments to increase visibility, reliability, and resiliency on and control of the distribution system enables the Company to transform DERs into system resources. In addition, combining the data generated from these investments with new modeling methodologies and advanced analytics will enable the Company to generate detailed forecasts for new DERs and load—along with simulations of the potential impacts of new DERs and load on the grid—to plan for the future needs of the grid and to address those needs before adverse impacts occur.

E. Value of a Transformed Distribution Grid to Customers

Foundational investments to transform the distribution grid will allow the Company to use the distribution system differently than it has historically, all for the benefit of customers.

Transformational investments in AMI, the CIP, intelligent grid devices, and automated control systems will enable the Company to improve operations (*e.g.*, reduced truck rolls; more predictive and efficient maintenance; increased visibility and control; optimized use of DERs), better forecast load shape, and predict future behaviors (*e.g.*, identifying and fixing grid problems before an outage occurs; enabling overall savings and cost management of demand-side management ("DSM") programs), resulting in a better, more informed customer experience. This value of a transformed distribution grid can be seen from the view of different types of customers.

Prior to grid transformation, all customers had to take specific action to report outages and then wait for the Company to deploy resources to bring the power back on. With transformational investments in AMI, CIP, intelligent grid devices, automated control systems (*e.g.*, OMS, FLISR), and resilience, customers will experience fewer outages and will not need to take action to report outages when they do occur. Instead, when outages do occur on the more connected and resilient grid, the outages reported through smart meters and other intelligent grid devices will prompt the dynamic system to automatically restore power to as many customers as possible, narrowing the scope of the outage and focusing effort on issues that require manual intervention. Additionally, grid visibility provided by the transformed grid will allow customers to receive proactive outage and restoration alerts—and more accurate information on expected restoration times, including detailed outage maps—allowing the fewer customers that are impacted to better adapt to the situation.

Prior to grid transformation, most residential customers received monthly energy usage data at a summary level through their bills. With transformational investments in AMI and the CIP, all residential customers can receive detailed interval energy usage data through convenient communication channels. The corresponding education will inform customers on how to take control of and manage their energy usage, if desired. These customers will also have the opportunity to participate in time-varying rates and innovative DSM programs that these investments will enable the Company to broadly offer. Such rate options and DSM programs can prompt behavioral changes that benefit customers through bill savings and reduced system costs. Indeed, customer have already begun to take advantage of these opportunities, with 10,000 customers enrolled in the Company's experimental time-of-use rate, the Off-Peak Plan (*i.e.*, Schedule 1G), and more than 14,000 email addresses added as a convenient communication channel for customers. Further, with transformational investments in voltage optimization, informed by the data from AMI and intelligent grid devices, most customers will see lower energy consumption without a noticeable difference in service level because of the more precise voltage control settings.

Prior to grid transformation, multi-family complex customers (*e.g.*, apartment complexes) had meters that limited the efficiency of the move-in / move-out process, a process that happens more frequently than for single-family homes. With transformational investments in AMI and the CIP, customers can change accounts the same day, leading to more efficient relocation, easier owner / tenant billing, and lower costs.

Prior to grid transformation, DER net metering customers had to engage in a largely manual application process, and then wait for a meter exchange. The meter exchange process alone could take up to 10 business days to schedule and complete, leading to potential interconnection delays for the customer. With transformational investments in AMI, CIP, intelligent grid devices, a DER management system ("DERMS"), and resilience, DER customers will (i) experience a much faster and seamless interconnection process, (ii) will no longer need a meter exchange, and (iii) will receive detailed information on how their DERs interact with the grid. Further, customers will maximize the value of their DERs through the connection with a resilient grid, and through opportunities to offer their DERs into programs that provide grid support or other functions. In addition, transformational grid investments have enabled a hosting capacity map that allows customers, and even localities, to evaluate optimal locations to interconnect DERs—a map that will continue to become more dynamic as additional AMI and intelligent grid devices are added to improve grid visibility. By empowering customers with the information to optimally locate DER, customers can realize reduced interconnection costs and potentially contribute to the deferral of other system investments.

Prior to grid transformation, the majority of EV customers did not have attractive options to encourage them to charge their vehicles during times when the demand for electricity is low. With transformational investments in AMI, CIP, and smart charging infrastructure, EV customers have access to more innovative programs and advanced rate options, such as the Company's Off-Peak Plan that can lead to bill savings and reduced system costs.

Prior to grid transformation, business customers were subject to sudden voltage fluctuations when outage events occurred on the distribution grid. Even when a customer did not experience a sustained outage, these voltage fluctuations have the potential to impact operational processes and facility production. The intermittency and changing power flows related to renewable generation introduce new dynamics to grid operation that, if not managed properly, have the potential to similarly impact these customers. Transformational investments in reliability and resiliency will eliminate certain outage events and the associated voltage fluctuations that ripple across the distribution grid, while also ensuring power is restored more quickly when it does go out. With transformational investments in AMI, intelligent grid devices, and automated control systems, the Company will have the situational awareness and control capabilities to manage grid operation so business customers can rely on voltage stability to ensure minimal disruption to their operations.

Prior to grid transformation, vital community resources are more dependent on grid reliability than ever before. Health and safety services, such as hospitals, water, and emergency services, carry the highest priority day-to-day and in a restoration event, closely followed by commerce and education, including internet services for home and work. More grid availability translates to availability for DER to contribute to system resources in the form of capacity factor. With transformational investments in resilient grid architecture, customers will have confidence that their growing reliance will be served.

Dominion Energy Virginia values the experience of its customers and believes that the Grid Transformation Plan will enable the Company to meet their changing needs and expectations.

II. Distribution Grid Planning

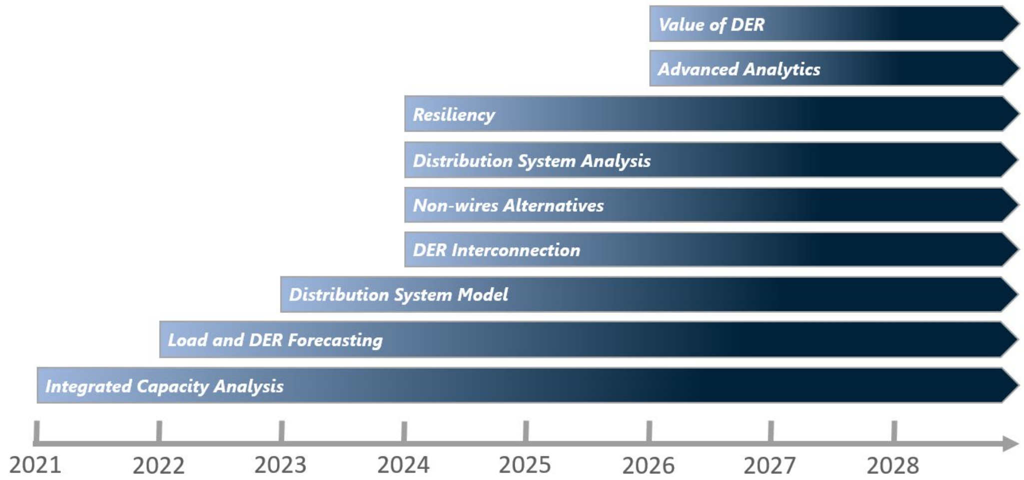
The fundamental changes in the energy industry discussed in Section I have driven not only the need to transform the distribution grid, but also to transform how distribution grid planning occurs.

In 2019, the Company presented a white paper that provided a conceptual first-look at its transition toward integrated distribution planning ("IDP"). The Company defines integrated distribution planning as a consolidated process to address the capacity, performance, reliability, resilience, and DER integration needs of the distribution grid. The white paper noted that the evolution to IDP requires changes related to people, technologies, and processes. Throughout, trained professionals are vital to leverage the technologies and optimize the processes. Technologies and secure communications that provide real-time visibility into the grid to the customer level are foundational to enable IDP. Processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analytical tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on the distribution system. These concepts remain true today.

The Company has made notable successes in the evolution toward IDP since 2019, including successes related to people, such as the centralization of its organizational structure such that the one team focuses on all distribution-related modeling and data analysis activities for load and reliability driven investments; technologies, primarily through development and implementation of Grid Transformation Plan investments; and processes, such as the development of an initial forecast of DERs by feeder and publications of hosting capacity maps for different types of DERs.

In 2021, the Company noted its continued work on a roadmap for IDP that adds tangible goals and timeframes to IDP maturity and stated its intention to present that roadmap in 2023. The Company's current IDP roadmap is attached as Appendix C to this GT Plan Document (the "2023 IDP Roadmap" or the "Roadmap"). The Roadmap presents tangible goals for the components of IDP on which the Company plans to focus in the near term. Figure 2 provides a visual representation of the Roadmap.

Figure 2: 2023 IDP Roadmap



The IDP concept is not static, and further changes are expected in the next decade. But the 2023 IDP Roadmap sets the Company on a trajectory to give higher priority to foundational components of IDP, such as advanced forecasting and system model enhancements, while balancing the resources required to implement these components and the interdependencies among many of the components.

III. Development of Grid Transformation Plan

The Company has engaged in an iterative process to develop the Grid Transformation Plan presented in this document. Guided by the policy objectives of the Commonwealth to facilitate the integration of DER and enhance distribution grid reliability and security, the Company incorporated its experience-based knowledge with input from customers and stakeholders; with lessons from the experiences of peer utilities; and with guidance provided by the Commission in prior orders.

A. Internal Process

The Company consistently tracks developments in the energy industry and challenges for its distribution system. The Company collaborates with its peer utilities and learns from their experiences. The Company keeps current with information published by various industry groups and has engaged with these industry groups to gain additional knowledge and perspective. The Company also continues to engage an industry expert, West Monroe Partners, as a knowledgeable partner in the development and implementation of a plan to modernize the distribution grid. The Company intentionally tests certain components of the GT Plan on a smaller scale prior to full scale deployment, such as AMI and mainfeeder hardening. And the Company continuously incorporates lessons learned from prior GT Plan investments into its strategy for deployment of GT Plan investments into the future. All of this knowledge coalesced to create the framework for and to ensure prudent implementation of the Grid Transformation Plan.

B. Customer Engagement

Dominion Energy Virginia strives to meet its customers' energy needs while providing a seamless customer experience. To that end, the Company frequently seeks feedback from its customers in various forms and forums. The Company has also sought specific feedback to assist in the development of the Grid Transformation Plan. The Company intends to continue this customer engagement to assess the priorities included in the GT Plan.

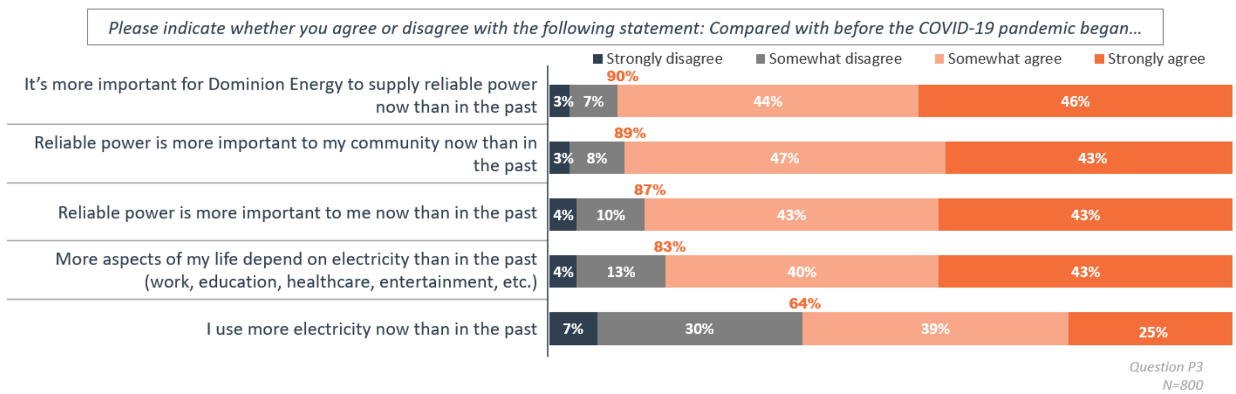
The Company receives customer feedback on a daily basis. The Company strives not only to quickly and fairly resolve any customer issue, but also to identify trends and possible process improvements. The Company will continue to engage with customers on an ongoing basis in its efforts to meet customer needs and expectations.

In 2019, the Company presented the results of a survey conducted by Maslansky + Partners ("Maslansky") to evaluate customer priorities related to the Grid Transformation Plan. Maslansky based this effort on a nationwide survey fielded by Edison Electric Institute ("EEI") on the "Voice of the Customer," and, where applicable, compared the results of the Virginia survey and the national study. In 2021, the Company contracted with an external third-party to conduct enterprise-wide and Virginia-based research to evaluate customer priorities.

To further understand and confirm customer priorities, in 2023, the Company engaged Maslansky to conduct an updated survey to evaluate customer priorities related to the Grid

Transformation Plan, with a focus on customer expectations around reliability in light of the pandemic. The survey indicated that customers report the value of reliable energy has increased since the pandemic, with 90% of customers surveyed agreeing that "it's more important for Dominion Energy to supply reliable power now than in the past." Figure 3 shows the results of this survey related to the importance of and dependence on reliable energy.

Figure 3: Maslansky Findings on Importance of and Dependence on Reliable Energy



C. Stakeholder Engagement

In furtherance and development of the Company's GT Plan and related initiatives, the Company began a series of stakeholder sessions in mid-2019 to inform and develop goals for a modern grid and the customer experience.

Ahead of its Grid Transformation Plan filing in 2019, the Company engaged an industry expert, Navigant, to facilitate an external stakeholder process. Attendees included a range of stakeholders with varying interests, from environmental advocates to municipality representatives to low-income advocates. Commission Staff also attended the stakeholder process. Navigant facilitated a series of workshops that guided the conversation on the stakeholders' vision and objectives for grid transformation. Through collaborative conversations, a group of the stakeholders identified four goals for grid transformation:

- **Optionality**: Enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access.
- **Sustainability**: Evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles.
- **Resiliency**: Build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management.
- **Affordability**: Deliver value for customers by optimizing demand and seeking to reduce system and customer costs.

Using these goals as a guide, Navigant led an exercise for stakeholder groups to prioritize grid capabilities that any plan for grid transformation should enable. Consistent across all stakeholder groups were investments that enabled two capabilities: (i) integrate and optimize DERs and (ii) provide relevant, data-enabled options that enable customers to meet their goals. In addition, highly prioritized by at least one stakeholder group were investments that enabled the following capabilities: (iii) increase monitoring and visibility; (iv) accommodate two-way power flows; (v) enable voltage monitoring and control, supporting load management and peak shifting; (vi) simplify interconnection for residential customers; and (vii) harden for resiliency and security.

Ahead of the Grid Transformation Plan filing in 2021, the Company re-convened stakeholders to provide an update and opportunity for feedback on various GT Plan components over three sessions. The first session focused on AMI, the CIP, and other customer-related programs such as the Company's Schedule 1G (marketed as the Off-Peak Plan). The second session focused on the Company's approved Smart Charging Infrastructure Pilot Program and other electrification initiatives. The third session focused on the Company's proposed intelligent grid device deployment and DERMS, and how the GT Plan more generally supports the objectives of the VCEA. Attendees at these sessions included a range of stakeholders with varying interests, from environmental advocates to state agency representatives to low-income advocates. Commission Staff also attended the stakeholder process.

Ahead of this 2023 Grid Transformation Plan filing, the Company again re-convened stakeholders to provide an update and opportunity for feedback. The Company provided status updates on specific projects of interest from Phases I and II, including AMI, the CIP, targeted corridor improvement, mainfeeder hardening, substation technology deployment, intelligent grid devices, and physical security. The Company also provided a preview of projects for which it planned to seek approval in Phase III, including the NWA Program. The Company invited to this session Commission Staff, respondents from prior GT Plan proceedings, and other stakeholders with varying interests, including state agency representatives and low-income advocates.

The Company intends to continue engagement with stakeholders as its grid transformation efforts proceed.

D. Environmental Justice Evaluation

Under the Virginia Environmental Justice Act ("VEJA"), environmental justice is defined as the fair treatment and meaningful involvement of every person—regardless of race, color, national origin, income, faith, or disability—regarding the development, implementation, or enforcement of any environmental law, regulation, or policy. The primary tenets of the VEJA—fair treatment and meaningful involvement—were not created anew in the Commonwealth, but instead stand and build upon existing, governmental environmental justice policies stemming back to Executive Order 12898 issued by President Clinton in 1994. This Executive Order focused on disproportionately high and adverse human health or environmental effects, including high risks from environmental hazards and impacts on populations relying on subsistence lifestyles, of federal agencies' actions on minority populations and low-income populations.[6]

[6] Executive Order 12,898 §§ 1-101, 3-301, 4-401 (Feb. 16, 1994), *available at* https://www.archives.gov/files/federal-register/executive-orders/pdf/12898.pdf.

Like its federal predecessor, under the VEJA, "fair treatment" focuses on the negative and adverse environmental impacts of a project, and is defined to mean "the equitable consideration of all people whereby no group of people bears a disproportionate share of any negative environmental consequence resulting from operations, programs, or policies." Similarly, "meaningful involvement" under the VEJA means "the requirements that (i) affected and vulnerable community residents have access and opportunities to participate in the full cycle of the decision-making process about a proposed activity that will affect their environment or health and (ii) decision makers will seek out and consider such participation, allowing the views and perspectives of community residents to shape and influence the decision." The VEJA defines "environment" broadly to mean "the natural, cultural, social, economic, and political assets or components of a community."

Dominion Energy Virginia is dedicated to meeting environmental justice expectations of fair treatment and meaningful involvement by being inclusive, understanding, and dedicated to finding solutions, and by effectively communicating with its customers and neighbors. The Company adopted an environmental justice policy in 2018 through which it committed to hearing, fully considering, and responding to the concerns of all stakeholders. Consistent with the VEJA, this commitment includes ensuring that a voice in decisions about siting and operating energy infrastructure is given to all people and communities. Communities should have ready access to accurate information and a meaningful voice in the project development process. The Company has pledged to be a positive catalyst in its communities.

Generally, when conducting an environmental justice review, one evaluates: the type of activity (*e.g.*, a project or program at issue); where it will occur; what type of environmental impacts are likely; if any impacts, are they negative or adverse; and, whether there are environmental justice communities (as that term is defined by the VEJA) that might suffer the negative or adverse environmental impacts of the proposed activity. These factors are consistent with the VEJA, U.S. Environmental Protection Agency guidance, and currently accepted best practices. The VEJA defines environmental justice communities as identifiable, discrete communities within a specific geographic area. For example, the definition of "community of color" focuses on "any geographically distinct area," and the definition of "low-income community" focuses on "any census block group."

The outcome of one or more of the inquiries in a typical environmental justice review may result in a finding that no environmental justice concerns exist. For example, a proposed project to upgrade a computer system may not have an environmental impact on any community, let alone an environmental justice community. As noted above, the VEJA defines environmental justice communities as identifiable, discrete communities within a specific geographic area. Thus, in this example, because a discrete environmental justice community is not at issue, the environmental justice review under the VEJA would be at an end. Assuming there is an environmental justice community that might suffer negative environmental impacts of the proposed activity, then an analysis is done to determine whether that community would bear a disproportionate share of such impacts. As discussed below, in preparing the Grid Transformation Plan, Dominion Energy Virginia evaluated each proposed project to determine whether any environmental justice concerns exist.

The Grid Transformation Plan includes multiple projects, some of which will require work in communities throughout the Company's service territory, and some that will not. While all of the proposed work in this Plan is intended to benefit these communities, and all customers broadly, as discussed in Section IV.B, the Company remains committed to ensuring environmental justice. Five of the fourteen grid transformation projects proposed for Phase III do not have a physical component that would cause any environmental consequence—the CIP, DERMS, OMS, cyber security, and customer education. In addition, the Storage NWA Program will not have a physical component unless a specific energy storage resource is selected under the proposed process. The remaining eight Phase III grid transformation projects will require at least some work in communities. The Company proposes to deploy some of these projects broadly, and eventually in nearly every community it serves, such as the system-wide deployment of AMI and voltage optimization enablement. Other projects will focus on mitigating reliability, resiliency, and security risks in select areas, such as voltage island mitigation, substation technology deployment, and physical security.

The Company has engaged a third-party consultant to evaluate the eight Phase III grid transformation projects that will require at least some work in communities, and will use the results of this evaluation to inform its environmental justice strategy as it relates to the GT Plan. As discussed, in Section III.C, the Company has engaged in outreach with a number of stakeholders and stakeholders' representative groups regarding the GT Plan, and otherwise plans to continue with additional outreach and meaningful involvement activities as appropriate.

IV. Grid Transformation Plan

Virginia Code § 56-585.1 A 6 requires that any plan for electric distribution grid transformation projects "shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security." Based on the development process described in Section III, the Company presents a comprehensive plan designed to achieve all of the goals and objectives for grid transformation in a reasonable, prudent, and cost-effective manner.

The Grid Transformation Plan includes six core components: (i) AMI; (ii) CIP; (iii) grid improvements within two categories, grid infrastructure and grid technologies; (iv) transportation electrification; (v) security; and (vi) telecommunications infrastructure. Certain components, such as grid improvements, consist of multiple electric distribution grid transformation projects. The Plan also incorporates customer education related to the Company's grid transformation efforts generally, and to specific projects.

A. Interrelated Nature of Projects

The Company developed its Grid Transformation Plan as an integrated package of projects that work together for the benefit of customers to achieve the objectives of grid transformation—to facilitate the integration of DERs and to improve grid reliability and security. While some projects may provide benefits standing alone, the benefits increase exponentially when paired with the capabilities of other projects. The Company focused on the synergy between capabilities to ensure that it would not miss opportunities to benefit its customers. Some examples of these synergies follow, though they do not represent a comprehensive list.

The Company could have deployed a new CIP to replace its aging infrastructure and use it to manage customer billing. But the new CIP will transform the customer experience when it can use the data from AMI to provide customers detailed and timely education about their energy consumption, empowering customers to manage their energy usage to suit their individual goals.

The Company can (and did) publish a static hosting capacity tool with data obtained from existing sources, and refresh that tool quarterly. But the distribution grid is now a dynamic system that changes daily as any number and type of DERs are installed along feeders. When fed by the data from AMI and intelligent grid devices, the hosting capacity tool can refresh more frequently with the most up-to-date information, providing customers, localities, and developers with the tools to make the right decisions for them on siting DERs.

The Company could have deployed DERMS to manage the growing population of DERs. But DERMS will best optimize use of DERs for grid support when informed by the data collected from AMI and intelligent grid devices over a secure telecommunications network. Every additional data element that DERMS collects helps it to become smarter—thus providing grid operators additional tools—in assessing real-time grid constraints and managing DERs accordingly. Further, investments in reliability and resiliency will ensure that these DERs are available to provide grid support on which the system can rely.

The Company could have deployed intelligent grid devices to provide situational awareness on the distribution grid. These devices alone would support many other grid transformation projects with the data collected, as described in the examples above. But when paired with the FLISR control system, the Company will unlock significant reliability improvements for customers at a small incremental cost, leading to faster overall system restoration time.

Finally, the Company could deploy OMS to replace its aging infrastructure and to manage outages on its modern distribution system. But when fed by the data from AMI and intelligent grid devices and when paired with the functionality of FLISR, a new OMS can assess field conditions to better identify and analyze outage events.

B. Projects

The sections that follow provide an overview of each project incorporated into the Grid Transformation Plan and summarize the need for the specific project, the deployment timeline, the alternatives considered, and the benefits. Refer to Appendix B as needed for context, which provides a description of the existing distribution grid. Finally, each section provides an overview of the Company's progress to date on the project, if applicable. These sections are intended to provide a high-level overview only; more information on each project is provided by the sponsoring Company witness.

1. Advanced Metering Infrastructure

Dominion Energy Virginia plans to fully deploy AMI across the service territory. Through this technology, the Company can remotely read data gathered by smart meters and send commands, inquiries, and upgrades to individual smart meters.

- Need. Modernize the distribution grid by digitally gathering customer energy usage data in specific increments and other premises-level data; replace aging AMR meters and associated equipment and systems.
- Deployment Timeline. Full deployment over six-year period of 2019 to 2024.
- Alternatives Considered. No alternatives considered from a general metering technology perspective, as the Company does not consider AMR meters as a viable metering solution on a modern distribution grid. Prior to deployment of AMI, considered alternative systems, vendors, and deployment timeline. Now that deployment is near complete, no alternative systems considered. The Company continues to consider new, compatible smart meters as they are developed and released to the market.
- Benefits. Advanced time-varying rates; targeted DSM programs; reduced components of the cost of service; enhanced grid operations; enhanced DER integration; avoided capital maintenance investments.
- Phase III Request. Deploy approximately 195,000 smart meters and associated infrastructure; optimize the AMI mesh network.
- Progress to Date. Installed approximately 1.95 million smart meters as of December 31, 2022; avoided almost 772,000 truck rolls in 2022 alone; reduced bad debt expense in areas where AMI has been deployed; reduced "found ons" by approximately 70% in

areas where AMI has been deployed; launched Schedule 1G for customers in areas where AMI has been deployed, with the pilot reaching its participant cap in less than one year.

2. Customer Information Platform

Dominion Energy Virginia proposes to implement a new CIP that will replace existing systems that support different aspects of the customer experience, including aging and outdated systems. As part of this project, the Company also proposes to complete a bill redesign to make it more understandable and easy to read.

- Need. Modernize the customer experience; replace antiquated customer information system.
- Deployment Timeline. Full deployment of all four projects by 2024; Core Project to replace existing systems live in second quarter of 2023.
- Alternatives Considered. Prior to Phase I, considered the alternative of a patchwork of applications and manual processes. Now that deployment of the Core Project is near complete, no alternatives considered. Only alternative to the bill redesign project is to not complete the project.
- Benefits. Modernized customer relationship; advanced time-varying rates, DSM programs, and other customer offerings at scale; reduced manual workarounds; avoided capital maintenance investments; improved customer satisfaction.
- Phase III Request. Finalize deployment of CIP by completing the customer bill redesign.
- Progress to Date. Launched Outage Center app in November 2019, with more than 490,000 downloads since its launch as of December 31, 2022; launched notification Preferences in April 2020; Core Project scheduled to go live in the second quarter of 2023.

3. Grid Infrastructure

Within the category of grid infrastructure, the Company proposes: (a) hardening mainfeeders; (b) deploying targeted corridor improvement activities; and (c) mitigating voltage islands.

a. Mainfeeder Hardening

Dominion Energy Virginia proposes to complete hardening work (*i.e.*, physically strengthening infrastructure; improving distribution system architecture and connectivity) on a targeted population of mainfeeders.

- Need. Improve reliability on the worst performing mainfeeders.
- Deployment Timeline. Harden 195 mainfeeders through completion of the GT Plan.
- Alternatives Considered. Considered addressing issues on the identified mainfeeders reactively as outages occur rather than proactively, hampering efforts to improve reliability for these customers. Considered alternative solutions and identified the appropriate hardening solution for each mainfeeder based on detailed engineering and design.

- Benefits. Improved reliability and resiliency; faster recovery after severe weather events.
- Phase III Request. Harden a total of 111 mainfeeders, targeting 44 in 2022 and 2023 and an additional 67 in the years 2024, 2025, and 2026.
- Progress to Date. Completed hardening work on 17 mainfeeders as of December 31, 2022.

b. Targeted Corridor Improvement

Dominion Energy Virginia proposes several vegetation management programs to improve grid reliability and resiliency while minimizing environmental impacts.

- Need. Improve accessibility to right-of-way; remove risk related to ash trees, hazard trees, and tree overhang.
- Deployment Timeline. Ash tree remediation completed by end of 2024; ground floor maintenance completed by end of 2027; hazard tree pilot program completed by end of 2024; tree overhang pilot program completed by 2026.
- Alternatives Considered. Considered addressing ash trees, ground floor growth, and hazard trees reactively rather than proactively, potentially affecting reliability and resiliency, increasing costs for restoration and maintenance work, and requiring higher cost options for ash tree removal. Considered different scopes for pilot programs.
- Benefits. Improved reliability and resiliency; improved access to right-of-way.
- Phase III Request. Continue ash tree mitigation and ground floor maintenance programs; pilot program focused on surveying and removal of hazard trees; pilot program focused on removal of tree overhang.
- Progress to Date. Removed over 16,900 ash trees; treated over 22,300 miles of right-of-way as of December 31, 2022.

c. Voltage Island Mitigation

Dominion Energy Virginia proposes to mitigate voltage islands, which are single substation transformers that serve a population of customers without the support of available load transfer capability within the substation or through field tie switches to adjacent feeders.

- Need. Mitigate risk of an extended outage for customers served by voltage islands if the single substation transformer fails.
- Deployment Timeline. Address 19 voltage islands through completion of the GT Plan.
- Alternatives Considered. Considered not mitigating the risk of extended outages for customer served by voltage islands. Considered alternate solutions and identified the appropriate solution for each voltage island.
- Benefits. Reduced risk of extended outages; improved reliability.
- Phase III Request. Address six voltage islands.
- Progress to Date. Addressed three voltage islands as of December 31, 2022.

4. Grid Technologies

Within the category of grid technologies, the Company proposes: (a) installing intelligent grid devices; (b) deploying FLISR; (c) implementing a DERMS; (d) conducting and publishing hosting capacity analysis; (e) implementing an enterprise asset management system ("EAMS"); (f) installing a new OMS; (g) enabling voltage optimization through infrastructure upgrades; (h) deploying modern technologies at substations; (i) establishing a program to seek energy storage systems as a non-wires alternative solution at identified locations on the distribution grid; and (j) demonstrating microgrid capabilities at the Locks Campus.

a. Intelligent Grid Devices

Dominion Energy Virginia proposes to install intelligent grid devices ("IGDs") to provide the data and control necessary to restore power and manage distribution grid voltages and power flows in a system with increasing penetrations of DERs.

- Need. Monitor the distribution grid; remotely control the distribution grid to restore power and address power quality issues created by DERs.
- Deployment Timeline. Deploy IGDs on 685 mainfeeders or feeder segments through completion of the GT Plan.
- Alternatives Considered. Considered different equipment and vendor options to achieve the needed situational awareness and grid control functionality. Considered alternative deployment options in terms of the number and location of devices on each feeder based on detailed engineering and design, and good utility practice.
- Benefits. Increased data about the distribution grid, which enables remote monitoring and control of grid operations; enhanced integrated distribution planning; improved hosting capacity tool; improved reliability.
- Phase III Request. None.
- Progress to Date. Deployed 91 IGDs on 24 feeders as of December 31, 2022.

b. FLISR

Dominion Energy Virginia proposes to install a distribution automation system called FLISR, which stands for fault location, isolation, and service restoration, to leverage the capabilities of intelligent grid devices to improve reliability.

- Need. Improve reliability; leverage the full capabilities of intelligent grid devices.
- Deployment Timeline. Upgrades integrated into ADMS by the third quarter of 2023.
- Alternatives Considered. Considered not leveraging the capabilities of IGDs to improve customer reliability through FLISR; rejected alternative because the incremental cost of FLISR software is justified by the reliability improvements for customers. Considered alternative software vendors.
- Benefits. Improved reliability; reduced outage-related O&M expenses; improved customer satisfaction.
- Phase III Request. None.
- Progress to Date. Began software installation and configuration

c. DER Management System

Dominion Energy Virginia proposes to deploy DERMS to monitor, control, and optimize increasing levels of DERs on the Company's system to maintain a safe and reliable grid.

- Need. Manage increasing volumes of DERs.
- Deployment Timeline. Complete initial installation by 2024; complete additional integrations by 2026.
- Alternatives Considered. Considered using a patchwork of manual processes to manage the increased volumes of DERs of various sizes and types; rejected alternative because of the objectives of FERC Order 2222, the complexity of operating in this manner, and the risk to system reliability and security as penetration increases. Considered alternative software vendors.
- Benefits. Enhanced monitoring and optimization of DERs; enabled customer programs at scale, such as EV managed charging and vehicle-to-grid; facilitated non-wires alternatives.
- Phase III Request. Continue to install DERMS.
- Progress to Date. Selected vendor for the DERMS platform.

d. Hosting Capacity Analysis

Dominion Energy Virginia proposes to complete and publish a hosting capacity analysis, and to refresh this analysis on a regular basis.

- Need. Provide customers, localities, and developers guidance about which sections of the distribution system may be more suitable to site new DERs.
- Deployment Timeline. Initial hosting capacity tool launched January 2021; additional capabilities implemented in 2022 for smaller generation projects.
- Alternatives Considered. Considered not providing this information to customers and developers, increasing their risk related to siting DERs in terms of costs to interconnect.
- Benefits. Increased information for customers, localities, and developers about how DERs can be placed at each point on the distribution grid without causing voltage or loading problems; increased proliferation of DERs.
- Phase III Request. None.
- Progress to Date. Launched a utility-scale hosting capacity tool in January 2021 and a behind-the-meter-scale hosting capacity tool in April 2022, available at https://www.dominionenergy.com/projects-and-facilities/electric-projects/energy-grid-transformation/hosting-capacity-tool; over 2,600 unique page views as of December 31, 2022.

e. Enterprise Asset Management System

Dominion Energy Virginia proposes to implement EAMS to improve its asset management practices by assessing the health and performance of physical distribution grid assets and to drive predictive maintenance activities.

- Need. Improve asset management practices.
- Deployment Timeline. System deployed in 2024.
- Alternatives Considered. Considered continued use of a patchwork of manual processes and isolated data system to manage distribution grid assets; rejected alternative because it would result in repeated reactive tactics and the inability to develop proactive and predictive strategies to mitigate equipment-related risk and realize asset life optimization opportunities.
- Benefits. Improved capabilities and strategies for managing the procurement, deployment, maintenance, and retirement of distribution equipment and devices.
- Phase III Request. None.
- Progress to Date. Selected vendors to support implementation of EAMS.

f. Outage Management System

Dominion Energy Virginia proposes to install a new OMS to replace an outdated operating system that cannot accommodate the complexity that a modern distribution grid requires.

- Need. Replace outdated operating system; leverage the full benefits of other GT Plan investments; modernize customer engagement.
- Deployment Timeline. Complete deployment by the fourth quarter of 2025.
- Alternatives Considered. Considered alternatives related to the timing of installation. Considered alternative vendors.
- Benefits. Restoration efficiency and productivity; improved customer experience.
- Phase III Request. Install OMS.
- Progress to Date. Not applicable.

g. Voltage Optimization Enablement

Dominion Energy Virginia proposes to make the improvements necessary to enable voltage optimization on the feeders where AMI has been installed.

- Need. Enable voltage optimization to achieve energy savings for customers by performing the necessary infrastructure improvements, as identified by data from AMI.
- Deployment Timeline. Complete infrastructure improvements that support implementing a 1% energy savings through voltage optimization capability, estimated at approximately 56,000 customer premises to be addressed.
- Alternatives Considered. Considered lesser percentage voltage reductions to target, which affects the necessary infrastructure improvements and resulting energy savings.

- Benefits. Broadly-enabled voltage optimization, which will result in generally lower voltage control settings leading to lower energy consumption for most customers without a noticeable difference in service level.
- Phase III Request. Complete infrastructure improvement to address approximately 28,000 customer premises.
- Progress to Date. As of December 31, 2022, completed 145 voltage optimization enablement service premises. Received approval of voltage optimization software deployment in January 2023.

h. Substation Technology Deployment

Dominion Energy Virginia proposes to modernize certain distribution substations by upgrading electromechanical relays; deploying substation communication protocol and power quality monitoring equipment; and piloting advanced substation technology.

- Need. Integrate DERs; improve reliability, power quality, and safety; study advanced substation technology.
- Deployment Timeline. Modernize 44 substations through completion of the GT Plan; deploy advanced substation technology as appropriate based on outcome of pilots.
- Alternatives Considered. Considered addressing substation equipment issues reactively rather than proactively; rejected alternative because it could result in an inability to effectively integrate DERs or feeder automation, such as FLISR, on the associated feeders.
- Benefits. Support for the integration of DERs while maintaining voltage stability; improved reliability, power quality, and resilience of the distribution grid; improved visibility and control; enhanced understanding of advanced substation technology.
- Phase III Request. Modernize 20 substations.
- Progress to Date. Began design, procurement, permitting, and construction at targeted substations. Installed 75 power quality monitors as of December 31, 2022.

i. NWA Program

Dominion Energy Virginia proposes to implement a non-wires alternative program to identify opportunities in which a traditional infrastructure investment may be deferred or avoided by investing in an alternative solution, with initial focus on energy storage systems.

- Need. Gain experience with integrated distribution planning concept in a manner that will provide useful information as the Company moves forward with NWAs. Address requirement from the VCEA related to the deployment of energy storage.
- Deployment Timeline. First RFP for NWA solutions issued in 2024.
- Alternatives Considered. Considered alternative timelines for implementing NWA Program. Considered seeking NWA solutions in addition to energy storage.
- Benefits. Address VCEA requirement that the deployment of energy storage involved non-wires alternatives program; experience with NWAs; potential deployment of energy storage to meet VCEA development targets, and associated experience with energy storage; potential deferment of traditional capital investments.

- Phase III Request. Approval of process used to solicit and, if selected, implement NWA solutions.
- Progress to Date. Not applicable.

j. Locks Campus Microgrid

Dominion Energy Virginia proposes to study a new technology—microgrids—by installing one at its Locks Campus near Petersburg, Virginia.

- Need. Obtain experience with microgrids.
- Deployment Timeline. Construction completed by third quarter of 2024.
- Alternatives Considered. Not obtaining experience with microgrids.
- Benefits. Enhanced understanding of microgrids from real-world data and testing of DER grid support and islanding capabilities.
- Phase III Request. None.
- Progress to Date. Awarded engineering, procurement, and construction contract; began field construction.

5. Transportation Electrification

Dominion Energy Virginia plans to offer rebates and install a limited number of Company-owned charging stations through its Smart Charging Infrastructure Pilot Program.

- Need. Support EV adoption while minimizing the impact of EV charging on the distribution grid; manage future EV charging load.
- Deployment Timeline. Offer rebates for the electrical infrastructure and upgrades at EV charging sites and rebates for the smart charging equipment that enables managed charging in Phase I; install four Company-owned fast charging stations.
- Alternatives Considered. Considered a "do nothing" scenario, as well as scenarios base on lower or higher EV adoption rates.
- Benefits. Energy and demand savings; fuel and maintenance savings for EV drivers; reduced greenhouse gas emissions.
- Phase III Request. None.
- Progress to Date. Issued rebates for 110 charging stations through November 30, 2022, with additional rebates to be issued pending installation and verification of selected charging stations; submitted permit for four Company-owned fast charging stations.

6. Security

Dominion Energy Virginia will continue to protect the distribution grid by providing adequate and cost-effective security control measures to manage the growing threat to the energy sector and to protect from cyber and physical attacks.

a. Physical Security

The Company plans to enhance physical security at key distribution substations.

- Need. Protect the distribution grid from security threats, thus protecting the Company and its customers.
- Deployment Timeline. Enhance physical security at 45 substations through completion of the GT Plan.
- Alternatives Considered. Considered not enhancing physical security at critical distribution substations; rejected alternative because it would leave these substations vulnerable to threats.
- Benefits. Improved detection, monitoring, and response time to potential security threats.
- Phase III Request. Enhance physical security at 18 critical distribution substations.
- Progress to Date. Enhanced physical security at three critical substations as of December 31, 2022. Near competition on seven additional substations.

b. Cyber Security

The Company plans to protect the investments proposed in the Grid Transformation Plan through the necessary cyber security investments.

- Need. Protect the distribution grid from security threats, thus protecting the Company and its customers.
- Deployment Timeline. As needed to protect other approved grid transformation projects.
- Alternatives Considered. Considered cyber security solutions as needed based on the security needs of the specific project, leveraging existing solutions where possible.
- Benefits. Avoided attacks on the system; mitigated risk of new or emerging threats.
- Phase III Request. Cyber security solutions as needed to protect other Phase III grid transformation projects.
- Progress to Date. Leveraged existing agreements and solutions, requiring limited cyber security improvements to support other GT Plan projects.

7. Telecommunications

Dominion Energy Virginia proposes to deploy a comprehensive telecommunications strategy requiring multiple components specifically designed and deployed as an integrated solution to meet the wide-range needs of a transformed distribution grid. The strategy includes Tier 1, a high-speed broadband with very low latency network with redundancy; and Tier 2, a broadband network with redundancy, as well as increasing the capacity of the Company's network operations center ("NOC"). This strategy also includes upgrading identified telecommunication sites and replacing network infrastructure within identified substations.

- Need. Enable the secure communication required for a transformed grid. Enhance security, reliability, and resiliency of data transport.
- Deployment Timeline. Tier 1 by 2021; Tier 2 deployed through completion of the GT Plan; NOC capacity increases through completion of the GT Plan; telecommunication site upgrades by 2026; substation network upgrades completion of the GT Plan.

- Alternatives Considered. Prior to Phase I, various alternatives considered to address the wide range of business and technical requirements. Now that deployment of Tier 1 and Tier 2 has begun, no alternatives considered.
- Benefits. Secure, reliable, and resilient telecommunications infrastructure; enabled grid transformation projects that require real-time communications for situational awareness and grid control.
- Phase III Request. Continue deployment of Tier 2 telecommunication solutions; upgrade 12 identified telecommunications sites; replace network infrastructure at 156 identified substations.
- Progress to Date. Completed Tier 1 implementation. Deployed Tier 2 telecommunications solutions to over 142 facilities, including laying 149 miles of fiber. Increased capacity of the NOC to accommodate Tier 1 and Tier 2 completed work.

8. Customer Education

Dominion Energy Virginia plans to improve the customer experience by incorporating education into various Plan components and including general energy education. Appendix D includes the full details of the customer education plan. While this customer education plan focuses on enhanced capabilities enabled by GT Plan, it supplements the Company's overall efforts to educate its customers on topics ranging from available rate schedules to general energy education.

- Need. Provide customers with concise, consistent, and easy-to-understand educational content.
- Deployment Timeline. As needed to support other approved grid transformation projects.
- Alternatives Considered. Considered various communication channels based on the educational need.
- Benefits. Improved customer experience; enhanced understanding of GT Plan and related benefits.
- Phase III Request. Customer education as needed to support other Phase III grid transformation projects.
- Progress to Date. Developed and published concise, consistent, and easy-to-understand content via multiple external communications channels.

C. Alignment with Customer and Stakeholder Feedback

As discussed in Section III.B, the Company received customer feedback on a range of priorities associated with the Grid Transformation Plan as part of the 2023 Maslansky Survey. Figure 4 notes the top findings on what customers rank with highest importance.

Figure 4: Customer Feedback Priorities

	Customer Priorities
1	Completes work without needing follow-up
2	Responds quickly to replace faulty equipment
3	Completes scheduled work when they say they will
4	Protects equipment from hazards and wear-and-tear that can result in unexpected outages
5	Invests in advanced technologies that help prevent outages or reduce their duration
6	Adapts effectively in the event of disruptions or crises
7	Has an outage map that includes accurate estimates of outage time and progress in restoring power
8	Invests in technology that helps prevent outages and respond to them faster when they occur
9	Increases energy availability by identifying the ideal locations for new facilities
10	Allows me to set custom alerts so I can choose which notifications I want to receive and how I want to receive them

As shown in Figure 4, among attributes tested, those relating to outage response and prevention rise to the top as priority areas of focus. These findings support the proposed GT Plan investments and make clear that they will provide the types of benefits the Company's customers value most—enhanced reliability and accurate information.

As discussed in Section III.C, the Company initiated a series of stakeholder sessions in 2019 to inform and develop goals for a modern grid and the customer experience. Through the 2019 GT Plan stakeholder process, four goals were identified: (i) enable all customers with accessible, affordable electric service and engage customers with programs, education, and data access (Optionality); (ii) evolve to a clean and decentralized grid that integrates distributed energy resources, such as solar and wind, and electric vehicles (Sustainability); (iii) build a more resilient energy grid that will reduce the effects of outages with automation and advanced asset management (Resiliency); and (iv) deliver value for customers by optimizing demand and seeking to reduce system and customer costs (Affordability). GT Plan projects directly support each of these four goals, through deployment of technology to empower customers to make informed decisions about their energy usage, enabling increased adoption of DERs in a responsible manner, and delivering better reliability and fewer outages for customers.

D. Costs

The Company estimated costs for grid transformation projects using competitively-negotiated contracts and responses to competitive requests for proposals ("RFPs") and requests for information ("RFIs"), informed by prior experience. The Company's filing provides detailed information used to determine costs and includes the relevant contracts or summaries of the completed RFPs and RFIs.

In Phase I of the Grid Transformation Plan, the Company suggested, and the Commission approved, a maximum amount of investment—by project—deemed reasonable and prudent ("cost caps"). Should costs exceed the approved cost caps, those costs would be incurred at the Company's risk, and it would be the Company's burden to demonstrate reasonableness and prudence for any such incremental investment.

Figure 5 provides the cost caps for each component of the GT Plan. For Phases I and II, the cost caps shown are those approved by the Commission in the prudence determination proceeding or those approved or pending approval in a Rider GT proceeding. The amounts shown for Phase III represent the cost caps proposed by the Company, subject to further refinement during the course of the proceeding.

Figure 5: Phases I, II, and III Costs ($M)

Project	Phase I		Phase II		Phase III	
	Capital	O&M	Capital	O&M	Capital	O&M
AMI	---	---	$186.1	$12.2	$23.2	$23.2
CIP	$83.7	$27.0	$135.0	$68.9	$4.3	$0
Mainfeeder Hardening	$47.9	$0	---	---	$508.3	$0
Targeted Corridor Improvement	$0	$12.8	$0	$16.3	$0	$31.9
Voltage Island Mitigation	$6.7	$0	$11.4	$0	$25.3	$0
Intelligent Grid Devices	---	---	$29.1	$0.02	---	---
FLISR	---	---	$10.0	$0.9	---	---
OMS	---	---	---	---	$15.7	$1.0
DERMS	---	---	$5.2	$0	$8.2	$1.1
Hosting Capacity	$0.3	$0.05	---	---	---	---
EAMS	---	---	$18.8	$1.2	---	---
Voltage Optimization Enablement	---	---	$97.1	$0	$215.0	$0
Substation Technology Deployment	---	---	$32.1	$0	$144.1	$0
NWA Program	---	---	---	---	$0.1	$0.1
Locks Campus Microgrid	$12.3	$0.08	---	---	---	---
Physical Security	$9.4	$0	$37.3	$0.2	$71.0	$0
Transportation Electrification	$3.8	$16.2	---	---	---	---
Telecommunications	$53.0	$1.6	$97.9	$4.1	$83.0	$12.1
Cyber Security	$1.1	$0.4	$6.5	$2.8	$0.5	$0
Customer Education	$0	$2.7	$0	$3.0	$0	$1.1
Total*	**$211.5**	**$60.8**	**$666.5**	**$109.6**	**$1,098.7**	**$70.6**

*Totals may not add due to rounding

The Company has committed that the costs of the Plan associated with the deployment of AMI and the CIP in Phases I, II, and III will not be the subject of a rate adjustment clause petition. The Company received approval to recover costs related to the remaining Phase I projects through Rider GT. As to other phases of and projects in the Plan, the Company has not yet determined its plans for cost recovery.

E. Benefits

The overarching benefits of the Grid Transformation Plan are that it facilitates the integration of DERs and enhances distribution grid reliability and security. All proposed projects contribute to these core objectives in some way.

The Company engaged a third-party industry expert, West Monroe Partners, to generate a cost-benefit analysis ("CBA") model for the Grid Transformation Plan that quantifies the benefits of the GT Plan compared to the costs. Figure 6 presents the results of the CBA.

Figure 6: CBA Summary

GT Plan Cost-Benefit Model Summary

(Revenue Requirement Basis, $ in Millions)

BENEFITS & COSTS	NOMINAL	PV[1]
AMI-Centric Programs AMI, Time-of-Use Rate, and Peak-Time Rebate (incl. Cyber Security Expenses)		
BENEFITS[2] *(Asset Life)* **:**	**$1,523.9**	**$650.9**
Avoided/Deferred Capital	$428.5	$104.7
O&M Savings	$575.3	$287.6
Energy & Demand Savings	$217.2	$104.8
Reduction of Bad Debt & Energy Diversion	$303.0	$153.8
COSTS *(Revenue Requirement)* **:**	**$978.2**	**$606.9**
Net Benefit (Cost):	**$545.8**	**$44.0**
Benefit/Cost Ratio:	**1.6**	**1.1**
Grid Infrastructure Mainfeeder Hardening, Targeted Corridor Improvement, and Voltage Island Mitigation (incl. Cyber Security Expenses)		
BENEFITS[2] *(Asset Life)* **:**	**$4,311.1**	**$970.0**
Avoided/Deferred Capital	$73.8	$9.9
O&M Savings	$69.9	$20.9
Enhanced Reliability	$4,167.4	$939.2
COSTS *(Revenue Requirement)* **:**	**$2,399.8**	**$924.9**
Net Benefit (Cost):	**$1,911.3**	**$45.1**
Benefit/Cost Ratio:	**1.8**	**1.0**
Grid Technologies Intelligent Grid Devices, FLISR Software, OMS, DERMS, Hosting Capacity, EAMS, VO Enablement, Substation Technology Deployment, NWA Program, Locks Campus Microgrid, and Telecom (incl. Cyber Security Expenses)		
BENEFITS[2] *(Asset Life)* **:**	**$9,963.5**	**$1,940.7**
Avoided/Deferred Capital	$926.9	$92.2
O&M Savings	$127.1	$68.0
Energy & Demand Savings	$3,393.4	$640.1
Enhanced Reliability	$5,516.1	$1,140.4
COSTS *(Revenue Requirement)* **:**	**$3,543.8**	**$1,397.1**
Net Benefit (Cost):	**$6,419.7**	**$543.6**
Benefit/Cost Ratio:	**2.8**	**1.4**
Transportation Electrification Customer EV Programs (incl. Cyber Security Expenses)		
BENEFITS[2] *(Asset Life)* **:**	**$2,500.6**	**$309.4**
Avoided/Deferred Capital	$2,302.0	$248.9
Energy & Demand Savings	$198.6	$60.5
COSTS *(Revenue Requirement)* **:**	**$321.0**	**$111.3**
Net Benefit (Cost):	**$2,179.6**	**$198.1**
Benefit/Cost Ratio:	**7.8**	**2.8**
GT Plan Total[3]		
Total Net Benefit (Cost):	**$9,953.6**	**$294.8**
Total Benefit/Cost Ratio:	**2.2**	**1.08**

1Present Value (PV) calculated using Weighted Average Cost of Capital (WACC) of 6.951%

[2] O&M Savings, Energy & Demand Savings, Enhanced Reliability, and Reduction of Bad Debt & Energy Diversion are stated on a Cash Flow Basis

[3] GT Plan Total includes costs and benefits associated with CIP, Customer Education, Physical Security, and Cyber Security costs not tied to specific projects

As can be seen, the CBA model represents a positive business case from a financial perspective, providing over $294.8 million in net benefits to customers on a net present value basis, with a benefit to cost ratio of 1.08. Additional quantitative benefits include reduced greenhouse gas emissions, increased EV ownership savings, and positive economic development impacts. Some of the benefits derive from programs and offerings that the Company will implement once the proposed projects are deployed, including a time-of-use rate and a peak time rebate program. Including these in the CBA model reflects the Company's commitment to these programs and offerings

The CBA model focuses on quantifiable benefits, but the Grid Transformation Plan produces other qualitative, non-quantifiable benefits. For example, there are benefits that are difficult to quantify, like avoiding a cyberattack; providing resilient service to military bases, hospitals and communities; and providing customers with accurate and timely information that has implications for their daily lives.

The following sections highlight certain GT Plan benefits important to the Company and various stakeholders.

1. Time-varying Rates

Transformational investments in AMI and the CIP, when coupled with customer education and communication, enable the Company to broadly offer time-varying rates. Time-varying rates provide incentives for customers to shift their usage to off-peak periods when the cost of generating electricity is less expensive, which both reduces the demand on the Company's system and reduces the customers' bills. The Company has a concrete, definitive plan to implement time-varying rates on a system-wide basis—both a time-of-use rate and a peak-time rebate ("PTR") program. The Company has taken the initial steps outlined in its plan as presented in the 2021 GT Plan Document. Specifically, the Company launched its Off-Peak Plan—Schedule 1G—in January 2021. Schedule 1G was available to the first 10,000 customers who enrolled. While the Company estimated it would take four years to reach the enrollment cap, Schedule 1G reached 10,000 participants in less than one year on January 4, 2022. The Company recently filed for expansion of Schedule 1G to additional customers. In December 2022, the Company proposed a system-wide opt-in PTR program in its DSM proceeding, Case No. PUR-2022-00210. That case remains pending.

2. Demand-side Management Initiatives

The foundational and transformational investments proposed as part of the Grid Transformation Plan will enable enhanced and targeted DSM initiatives in many ways. Investment in the full deployment of AMI and the CIP will enable the Company to broadly offer enhanced demand response programs—such as time-varying rates, PTR, and managed charging for EVs—and to deploy new energy efficiency programs—such as voltage optimization. Additionally, the interval usage data captured by AMI will both enhance existing DSM programs and improve evaluation, measurement, and verification ("EM&V") of DSM programs. Finally, the deployment of DERMS will provide the capability to manage demand response programs going forward. All of these programs and enhancements should lead to savings for the individual customers who participate in the various DSM programs, but should also lead to system energy and demand savings that will benefit all customers. For example, voltage optimization utilizes the data collected from AMI and other intelligent grid devices to reduce the voltage supplied to customers to the optimum level, which results in lower energy consumption for most customers without a noticeable difference in service level.

3. Integrated Distribution Planning

As described in Section II, the fundamental changes in the energy industry have driven not only the need to transform the distribution grid, but also to transform how distribution grid planning occurs. The real-time data from AMI and intelligent grid devices, paired with automated control systems (*e.g.*, DERMS) and advanced planning tools have and will continue to be foundational to the transition to integrated distribution planning.

4. Reliability

Transformational investments in grid infrastructure and grid technologies will improve reliability for customers across the Company's service territory. While some projects, like mainfeeder hardening and voltage island mitigation, focus on targeted populations of customers, others will be deployed more broadly, such as targeted corridor improvement. The CBA model quantifies reliability benefits using the Department of Energy's Interruption Cost Estimate Calculator ("ICE Calculator"), a recognized method for determining the economic value of increased reliability. This tool has been updated multiple times over the past decade to improve the accuracy of the results, and the Company fully supports the quantified benefits presented. Additionally, Dominion Energy Virginia engaged with Lawrence Berkeley National Laboratory in 2020 on a multi-year project to refine the ICE Calculator and incorporate Virginia-specific data. Since 2020, updates to reliability survey questionnaires for residential and non-residential customers has been completed based on feedback provided by the Company and others involved in the initiative. In December 2022, a successful pre-test of the residential survey was conducted with a sample of Company customers. The survey of Company customers will be administered in the first half of 2023 until a statistically representative sample of Virginia-based customer feedback is collected. Lawrence Berkley National Laboratory plans to update the ICE Calculator with results from the first phase of survey activities by mid-2024.

5. Load Forecasting

The data obtained from AMI can also enhance the Company's load forecasting process. AMI data will permit the Company to examine consumption patterns on an hourly basis. This data can then be used to create consumption forecast models for various customer segment levels, for example, residential heating system type, electrification impacts, demand response and energy efficiency effects, and DER adoption. These feeder level forecasts can then be rolled up to a system level and compared against the Company's current forecasting methods.

6. Broadband Program

In addition to supporting grid transformation objectives, the foundational telecommunications investments proposed as part of the GT Plan also provide the opportunity to support expanded deployment of broadband in the Commonwealth through the Rural Broadband Program. The telecommunications project includes the extension of the Company's fiber network to substations and key facilities. The expansion of the Company's fiber network, particularly in rural unserved areas, provides opportunities to leverage the fiber network for the benefit of middle-mile expansion in unserved and underserved markets as a part of the Company's Rural Broadband Program. Not only does the fiber serve Dominion Energy Virginia's connectivity needs at key facilities, but it also supports existing and potential internet service providers' use of the fiber capacity to improve availability of broadband for commercial, government, institutional, and residential customers in unserved areas of Virginia. The Commission has approved rural broadband projects in Surry County, Botetourt County, Louisa County, Appomattox County, and in the Northern Neck region of Virginia.

F. Regulatory Process

The GTSA mandated that the Company petition the Commission for approval of a plan for electric distribution grid transformation projects. The GTSA also set forth the applicable standard for reviewing such petitions:

> In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the costs associated with such projects will be recovered through a rate adjustment clause under this subdivision or through the utility's rates for generation and distribution services; and without regard to whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision 8 d.[7]

The Commission must rule on any petition not more than six months after the date of filing.

To date, the Company has submitted the following petitions for prudence determinations:

- In July 2018, the Company submitted its petition for approval of Phase I of the GT Plan in Case No. PUR-2018-00100. The Commission issued its final order in that proceeding on January 17, 2019.
- In September 2019, the Company submitted its second petition for approval of Phase I of the GT Plan in Case No. PUR-2019-00154. The Commission issued its final order in that proceeding on March 26, 2020 (the "2019 Final Order"), and its order on reconsideration on April 27, 2020.
- In June 2021, the Company submitted its petition for approval of Phase II of the GT Plan in Case No. PUR-2021-00127. The Commission issued its final order in that proceeding on January 7, 2022 (the "2021 Final Order").

[7] Va. Code § 56-585.1 A 6.

In addition to prudence determination proceedings, the Company has submitted two petitions for cost recovery of Phase I projects through a rate adjustment clause designated Rider GT:

- In August 2021, the Company submitted its petition for initial approval of Rider GT in Case No. PUR-2021-00083. The Commission issued its final order in that proceeding on May 13, 2022.
- In August 2022, the Company a petition to update Rider GT in Case No. PUR-2022-00140. That proceeding remains pending.

Figure 5 in Section IV.D provides a list of the GT Plan projects that the Commission approved in Phases I and II, along with the associated cost caps.

In the 2019 Final Order, the Commission ordered the Company to file an annual report on or before March 31, 2021, and each year thereafter, to include reporting metrics proposed by the Company and other information directed by the Commission. In its 2021 Final Order, the Commission added additional requirements for the annual report. The Company filed its first annual report on March 31, 2021, in the docket for Case No. PUR-2020-00154. The Company filed its second annual report on March 31, 2022, in the docket for Case Nos. PUR-2020-00154 and PUR-2021-00127. The Company filed its third annual report on March 31, 2023. The Company will incorporate additional metrics and information into its annual reports for any additional projects approved as part of Phase III.

LIST OF ACRONYMS

Acronym	Meaning
ADMS	Advanced distribution management system
AMI	Advanced metering infrastructure
AMR	Automated meter reading
BEA RIMS	Bureau of Economic Analysis Regional Input-Output Modeling System
BESS	Battery energy storage system
BTM	Behind-the-meter
CAIDI	Customer average interruption duration index
CBA	Cost-benefit analysis
CBMS	Customer Business Management System
C&I	Commercial and industrial
CI	Customer interruptions
CIP	Customer information platform
CIS	Customer information system
CMI	Customer minutes of interruption
COBOL	Common business-oriented language
DA	Distribution automation
DAS	Data analytics system
DCFC	Direct current fast charging
DERs	Distributed energy resources
DERMS	Distributed energy resource management system
DOE	Department of Energy
DR	Demand response
DSM	Demand-side management
EAB	Emerald ash borer
EAMS	Enterprise asset management system
EE	Energy efficiency
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EM&V	Evaluation, measurement, and verification
EPA	Environmental Protection Agency
EV	Electric vehicle
FAN	Field area network
FERC	Federal Energy Regulatory Commission
FLISR	Fault location, isolation and service restoration
GHG	Greenhouse gas
GIS	Geographic information system
GT Plan	Grid Transformation Plan
GTSA	Grid Transformation and Security Act of 2018
ICE Calculator	DOE's Interruption Cost Estimate Calculator
IDP	Integrated distribution planning
IEEE	Institute of Electrical and Electronics Engineers

Acronym	Meaning
IGDs	Intelligent grid devices
INSI	Itron Networked Solutions, Inc.
IT	Information technology
kV	Kilovolt
kWh	Kilowatt-hour
LTC	Load tap changer
MDMS	Meter data management system
MPLS	Multi-protocol label switching
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Officials
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
NIC	Network interface card
NIST	National Institute of Standards and Technology
NOC	Network Operations Center
NPV	Net present value
NREL	National Renewable Energy Laboratory
NWA	Non-wires alternatives
O&M	Operations and maintenance
OMS	Outage management system
OT	Operational technology
Phase I	Grid transformation projects for 2019, 2020, and 2021 approved in Case Nos. PUR-2018-00100 and PUR-2019-00154
Phase IA	Phase I projects approved in Case No. PUR-2018-00100
Phase IB	Phase I projects approved in Case No. PUR-2019-00154
Phase II	Grid transformation projects for 2022 and 2023 approved in Case No. PUR-2021-00127
Phase III	Grid transformation projects proposed generally for 2024, 2025, and 2026 in Case No. PUR-2023-00051
PII	Personal-identifying information
PTR	Peak-time rebate
RAC	Rate adjustment clause
RFI	Request for information
RFP	Request for proposals
RPS	Renewable energy portfolio standard
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SCIP Program	Smart Charging Infrastructure Pilot Program
SONET	Synchronous optical networking
STATCOMs	Static compensators
SUP	Strategic Undergrounding Program

Acronym	Meaning
T&D	Transmission and distribution
TOU	Time-of-use
V	Volt
Va. Code	Code of Virginia
VCEA	Virginia Clean Economy Act of 2020
VEJA	Virginia Environmental Justice Act
VO	Voltage optimization

GLOSSARY

ADMS (advanced distribution management system): A software platform that supports and manages the full suite of distribution grid management and optimization technologies employed by the Company.

AMI (advanced metering infrastructure): An over-arching metering system, which includes smart meters, a field area network, and a back office system called the AMI head-end system.

AMI head-end system: A back office system that receives and processes the data for smart meters, and serves as an operating platform for the back office team responsible for operating and maintaining AMI. The AMI head-end system also provides information from smart meters to other Company operating and analytical systems.

AMR (automated meter reading): A technology that records usage data and transmits it to the Company one-way. The Company reads these meters through drive-by readings using specially equipped trucks that receive the data through radio signals.

Automated control systems: Technology that allows for near real-time adjustment of the grid to changing energy loads, distributed generation, or feeder fault conditions without or with limited operator intervention.

Backfeed: The flow of electric power from the distribution grid to the transmission grid. Also represents the flow of electric power from a net metering distributed energy resource to the distribution grid during periods where distributed generation exceeds consumption at the premises.

Backhaul network: The backhaul portion of the network comprises the intermediate links between the core network and the small subnetworks at the edge of the network.

Base rates: The Company's existing rates for generation and distribution services.

BESS (battery energy storage system): A type of energy storage that stores energy for later discharge to the electrical grid.

CBMS (customer business management system): The core system delivering business functions such as customer service, account management, credit and collections, service orders, meter inventory, usage, billing, service address management, portfolio management, rates and financial based activities.

CIP (customer information platform): A combination of technologies, applications, and projects at the core of the customer experience, consisting primarily of the CIS, MDMS, customer portals, and other customer experience applications.

CIS (Customer Information System): Another term for CBMS.

Collector: A device deployed as a component of AMI designed to enable two-way communications to and from meters within range of the device. The device captures meter data and transmits via a dedicated backhaul communications network to the AMI head-end system to drive business processes.

Cyber security: Programs, techniques, and technology to protect the networks, devices, and programs from cyberattack.

DCFC (direct current fast charging): Electric vehicle charging technology capable of charging batteries to a 60 to 80 mile range state of charge within 20 minutes.

Decentralization: A concept that involves moving the electric grid away from relying solely on large centralized generating plants that supply power via the transmission grid to the distribution grid and ultimately end users, to a power grid where large generating plants and smaller distributed energy resources supply the grid simultaneously from two directions: the large generators through transmission lines and the smaller resources supplying from the distribution grid.

DER (distributed energy resource): A broad term used to describe resources connected to the distribution system, many of which are generation resources using renewable energy, such as solar and wind. DERs can also include, but are not limited to, energy storage, EVs, and demand response assets.

DERMS (distributed energy resource management system): A system that monitors and analyzes performance and status data from multiple distributed energy resources and has the ability to control those resources to maintain safety and reliability on the energy grid while maximizing benefits of the resources.

Distribution grid: The portion of the electrical utility system that delivers electrical power from the transmission grid through a substation transformer to end-use customers; typical distribution grid operating voltages range from 4 kV to 46 kV.

DSM (demand-side management): Activities that are designed to modify the level and pattern of electricity usage. DSM efforts in the Commonwealth focus primarily on two methods to manage demand: (i) energy efficiency and conservation, which aims to reduce the total amount of electricity used; and (ii) demand response (often peak shaving), which aims to shift the time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices on the electric grid.

EAMS (enterprise asset management system): A system that aggregates data and attributes of grid assets and provides capabilities to manage grid assets at all points in their life cycle, including procurement, deployment, and retirement. The system allows for collection of information related to the health and performance of grid components and analysis to drive life cycle decision making.

EM&V (evaluation, measurement, and verification): The collection of methods and processes used to assess the performance of demand-side management activities so that planned results can be achieved with greater certainty and future activities can be more effective.

Fault: An abnormal electrical condition caused by a short circuit on a feeder section.

Feeder: An electric distribution subsystem that begins at a substation and distributes electrical power within a localized service area. Feeders are comprised of mainfeeders, tap lines, and service lines.

FLISR (fault location, isolation, and service restoration): A distribution network system that works with intelligent grid devices such as switches, reclosers, line sensors, and a secure communications network to automatically isolate faulted feeder sections and reroute power to restore most customers in a matter of seconds or minutes.

GIS (geographic information system): A system designed to capture, store, analyze, and present spatial or geographic data, herein referring to distribution grid assets.

Grid hardening: Physical grid improvements that improve reliability and resiliency by rebuilding portions of the grid to eliminate outages and reduce damage for faster restoration.

Grid modernization: A broad term used to describe efforts to improve and modernize the grid.

Grid transformation: A broad term used to describe efforts to improve and modernize the grid.

Hosting capacity: The estimated amount of DERs that can be connected to each segment of the distribution grid without causing voltage or loading issues as determined by engineering analysis.

IGDs (intelligent grid devices): Various devices that provide situational awareness and control capability of the grid and enable two-way communication and centralized control of the power system.

Integrated distribution planning: A consolidated process to address the capacity, performance, reliability, resilience, and DER integration needs of the distribution grid integration needs of the distribution grid.

Intermittent generation: Generation resources that do not produce continuously available electricity due to external factors that cannot be controlled, such as solar and wind power. The power from such resources is non-dispatchable, meaning that it cannot be called upon at all times, only at times when the conditions for their power are present (*e.g.*, sun or wind) and the amount of power varies depending on those conditions.

Kilovolt (kV): Unit of measure for electric equipment and facilities representing 1,000 volts.

Latency: The amount of time it takes for a packet of data to get from one designated point to another through telecommunications networks.

Mainfeeder: The three phase sections of a feeder that distribute electrical power from substations to tap lines and individual customers.

MDMS (meter data management system): A system that processes and stores interval data used for billing, and calculates billable consumption for interval meter data.

Mesh network: The information network created from smart meters communicating with each other.

Microgrid: A group of interconnected loads and DERs that act as a small power grid, able to operate when connected to the larger distribution grid and also able to continue to operate as an "island" when there is an interruption or other grid disturbance that affects normal power flow from the grid.

Microgrid controller: A device that enables the establishment of a microgrid by controlling distributed energy resources and loads in a predetermined electrical system to maintain acceptable frequency and voltage while the microgrid is disconnected from the distribution grid.

MPLS (multi-protocol label switching): A mechanism for the routing of communications within a network as data travels across network nodes.

One-way energy: Power flow from a centralized location, such as a substation, along a distribution feeder, to end users.

OMS (outage management system): A centralized software solution and associated infrastructure for the purpose of analyzing and managing outage events on the distribution system. It uses field information and notifications from customers to identify outage events, create and manage restoration work requests, and provide restoration information to customers.

PTR (peak-time rebate) programs: Programs that provide incentive rewards for customers who achieve a desired reduction in usage during specific timeframes on abnormally hot or cold days.

Physical security: The protection of people, property, and physical assets from actions and events that could cause damage or loss.

Redundancy: In telecommunications, a process through which additional or alternate instances of network devices, equipment, and communication mediums are installed within network infrastructure. It is a method for ensuring network availability in case of a network device or path failure and unavailability.

Reliability: The ability of the distribution system to deliver uninterrupted power service to customers.

Repeater: An electronic device that receives a signal and retransmits it. Repeaters are used to extend transmissions so that the signal can cover longer distances or be received on the other side of an obstruction.

Resiliency: The ability of the power grid to withstand outages and maintain service to customers and recover from outages to restore service to customers.

RFI (request for information): A business process whose purpose is to collect written information about the capabilities of various suppliers.

RFP (request for proposals): A competitive bidding process where vendors and contractors offer to provide a service, asset, or good for a certain cost.

SCADA (supervisory control and data acquisition): A computer system that monitors and provides control of distribution assets, primarily located at substations.

Security information event and management (SIEM): A system to provide analysis of collected security events and logs to identify and detect potential security incidents as well as support incident response.

Single-phase: A segment of a power system consisting of one primary voltage conductor and one neutral conductor.

Situational awareness: Real-time perception of the grid and its environment that allows operators to project future outcomes as well as deal with present events.

Smart inverter: Inverters have the basic inverter function of converting direct current to alternating current, but also have additional capabilities such as voltage regulation, frequency support, and ride through capabilities (*i.e.*, staying online during grid events).

Smart meter: Electric meters that digitally gather energy usage data in specified increments (*i.e.*, interval data) and other related information as part of an AMI system.

Three-phase: A segment of a power system consisting of three primary voltage conductors and one neutral conductor.

Time-of-use rates: Rates that have pre-defined periods with tiered energy pricing that are generally aligned with the actual cost of producing electricity during those periods

Time-varying rates: Rates that provide incentives for customers to shift their usage to off-peak periods when the cost of generating electricity is less expensive, which both reduces the demand on the Company's system and can reduce the customers' bills.

Transmission grid: The high voltage part of the electrical grid that carries bulk power directly from large generating facilities to the distribution grid. Typical transmission grid operating voltages range from 69 kV to 500 kV.

Visibility: Real-time awareness of the grid's operating conditions.

Voltage optimization: The more precise control of distribution grid voltage that is possible with information from smart meters and a voltage control system.

Voltage island: A single substation transformer that serves a population of customers without the support of available load transfer capability within the substation or adjacent feeders. If a single transformer fails, all customers served by the substation could face an extended outage.

APPENDIX LIST

A. Sponsoring Witness Chart

B. Existing Distribution Grid

C. 2023 Integrated Distribution Planning Roadmap

D. Customer Education Plan

Appendix 3N: 2024 Integrated Distribution Planning Roadmap

Dominion Energy Virginia (or the "Company") defines integrated distribution planning ("IDP") as a consolidated process to address the capacity, performance, reliability, resilience, and distributed energy resource ("DER") integration needs of the distribution grid. In 2019, the Company presented a white paper regarding its preliminary plans to transition to an IDP approach (the "2019 White Paper"). Transitioning from traditional distribution planning processes to IDP is an industry-wide effort as the electric power system continues its fundamental shift from a world of centralized large-scale generation and a one-way power flow to the evolving paradigm of all types and number of DERs and a dynamic system with bidirectional and constantly changing power flows. The traditional distribution grid was not engineered and built for this evolving purpose. Consequently, the Company has actively engaged in IDP efforts and will continue to do so as IDP concepts further mature and evolve over the next decade and beyond.

This IDP roadmap provides an overview of the Company's efforts and successes thus far to transition to IDP and establishes tangible goals and timeframes as the Company's distribution planning processes shift toward IDP.

I. Background on Company IDP Efforts

In 2019, Dominion Energy Virginia presented the 2019 White Paper to provide a conceptual first look at its transition toward IDP.[1] The 2019 White Paper noted that the evolution to IDP requires changes related to people, technologies, and processes. Throughout, trained professionals are vital to leverage the technologies and optimize the processes. Technologies and secure communications that provide real-time visibility into the grid to the customer level are foundational to enable IDP. Processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analytical tools that consider a range of possible futures where varying levels of DER and emerging technologies are integrated into the distribution system. These concepts remain true today.

The Company has made notable successes in the evolution toward IDP since 2019, including:

- Centralization of the Company's organizational structure such that one team focuses on all distribution-related modeling and data analysis activities for load and reliability driven investments;
- Augmentation of technical staff focused on IDP capability development, including several advanced degree electrical power engineers;
- Continued development of DER and transportation electrification forecasts;
- Publication of three hosting capacity tools, one that allows customers and developers to see the sections of the distribution system that may be more suitable to site new clean energy installations; one that reflects the ability to interconnect behind the meter DER to

[1] *Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2019-00154, Petition, Exhibit 1 (filed Sept. 30, 2019).

the distribution grid; and one that provides available hosting capacity for transportation electrification;

- Installation of two battery energy storage systems ("BESS") to study future non-wires alternatives;
- Approval of a non-wires alternative ("NWA") pilot program under the Company's GTP Phase III filing;
- Continued construction of a microgrid to study future non-wires alternatives;
- Installation of advanced metering infrastructure ("AMI") across 99% of its distribution system, enabling the collection of premise-level load and voltage data;
- Development of an AMI data analytics application to identify and automatically correct meter to service transformer hierarchy relationships that received an AEIC Achievement Award;
- Groundbreaking research on load flow model phase error correction leveraging AMI data with a pending technical paper publishment;
- Initial installation of intelligent grid devices on selected feeders, enabling the collection of operational data that improves the accuracy of engineering models;
- Substation technology deployments that not only add enhanced situational awareness and increased system operability but provide increasingly granular data that refines the accuracy of the Company's engineering models;
- Initiated implementation of a DER management system ("DERMS"); and
- Participation in numerous research and development projects with EPRI and other industry entities focused on modernizing distribution grid planning, using automated processes and tools and data driven techniques to improve model data quality and further IDP goals and objectives.

The Company also engaged with Quanta Technology, LLC to solidify the conceptual framework through which the Company views the components of IDP.

II. IDP Roadmap and Implementation Timeline

The Company indicated its intention to present in 2023 a roadmap for IDP that adds tangible goals and timeframes to IDP maturity. Figure 1 provides the Company's current roadmap for IDP (the "2023 IDP Roadmap" or the "Roadmap") that is still relevant for the 2024 filing. The 2023 IDP Roadmap shows the IDP-related capabilities which the Company is committed to focusing on over the next several years, the goal associated with each of those capabilities, and an estimated timeframe. The IDP concept is not static, and further changes are expected in the next decade, as the Roadmap is based on the information known by the Company at this time. The Roadmap gives higher priority to foundational components of IDP, such as advanced forecasting and system model enhancements while balancing the resources (*e.g.*, personnel, funds) required to implement these components and the interdependencies among many of the components.

Figure 1: 2023 IDP Roadmap

IDP Component	Goal(s)	Estimated Timeframe
Integrated Capacity Analysis	- Develop static DER hosting capacity analysis for public viewing - Develop static electric transportation hosting capacity analysis for public viewing - Develop methodology to increase hosting capacity - Develop methodology to calculate dynamic hosting capacity - Develop methodology to estimate firm capacity contribution from variable DER	2021 to 2022 Begin in 2024 2025 – 2028 2025 - 2028
Comprehensive Distribution Grid Load and DER Forecasting	- Conduct competitive solicitation process for new forecasting software - Produce hourly (8760) forecasting on all feeders, including forecasts of load and DER	2022 to 2025
Distribution System Model	- Enhance the existing engineering model to reflect the low voltage system - Continue to improve the data quality and comprehensiveness of the engineering model	2024 Ongoing
DER Interconnection	- Develop software that can perform automated time series simulations for interconnection impact studies for utility-scale DERs	Begin in 2024
Non-wires Alternatives	- Assess load areas with anticipated capacity needs for use in the proposed NWA Program by leveraging EPRI's ADAPT engineering software	Begin in 2024
Distribution System Analysis	- Develop software that can perform automated detailed modeling for distribution planning studies - Develop software that can perform automated simulations for interconnection impact studies for utility-scale DERs - Develop software that can perform automated detailed modeling for selected engineering studies	Begin in 2024
Resiliency	- Engage with industry leaders (*e.g.*, IEEE, EPRI) to develop standard	2024 - 2028

IDP Component	Goal(s)	Estimated Timeframe
	metrics for measuring and assessing grid resiliency	
Advanced Analytics	- Identify and define advanced analytics use cases and applications supporting IDP - Define data and software requirements for advanced analytics applications to IDP - Develop and implement advanced analytics pilot project(s)	2026 - 2028
Value of DER	- Develop a methodology to calculate the location value of DER for specific value streams of interest	2026 - 2027

As can be seen in Figure 1, the next step in the evolution toward IDP requires a fundamental shift in software solutions to those that can be scaled to meet the computational requirements of the advanced analyses required of a modern distribution grid. This will include investments in and adoption of innovative technologies (*e.g.*, cloud computing, big data platforms) as well as the Company's continued engagement with research entities to develop these solutions. It will also require increased staffing in multiple disciplines (*e.g.*, engineering, economics, data science) to implement the solutions and processes. These requirements are not unique to the Company but are recognized as necessary by distribution grid planning organizations throughout the industry.

In the 2019 White Paper, the Company published a figure showing the evolution of IDP over time as enabling technologies are deployed throughout the Grid Transformation Plan. While the components shown on that maturity curve remain key components to the IDP framework that the Company envisions, the Company has produced an implementation timeline (*see* Figure 3.3.1 in the 2024 IRP) to align with the IDP Roadmap, lessons learned from its efforts over the past several years, and its engagement with EPRI and other industry activities.

The IDP Roadmap and implementation plans will set the foundation for achieving the Company's IDP vision. However, attaining that goal is expected to require more than 5 years, partly because some of these areas are still emerging and are expected to continue evolving within and beyond this timeframe; implementation plans therefore may need to be adjusted accordingly. Additionally, some of these components are necessarily projected in later years since regulatory and policy drivers, as well as commercial solutions, are either absent, incipient, or still being developed.

Appendix 4A: Virginia Bill Analysis

The Company calculated projected bills for each customer class under each primary Alternative 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 four years demonstrate not only that sales growth will continue but also that it will be different amongst classes. For example, since the SCC's directive in 2020, the Company has seen transmission costs for residential customers decline approximately 10% and increase approximately 9% for GS-4 customers.

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 2039
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - VCEA WITHOUT EPA, 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
DISTRIBUTION & GENERATION (BASE) [1]	61.82	61.82	61.82	61.82	60.93	60.93	60.71	60.72	60.72	60.72	60.72	60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	(0.47)	(0.43)	-	-	-	-	-	-
TRANSMISSION - RIDER T	19.72	19.72	20.29	16.60	12.91	15.58	19.40	21.62	24.31	27.39	30.50	33.42
FUEL - RIDER A	23.25	17.36	17.02	20.45	35.38	28.59	20.74	23.56	30.05	28.76	30.33	31.74
FUEL SECURITIZATION	-	-	-	-	-	-	3.37	3.13	2.78	2.93	2.78	2.73
DSM	1.13	1.13	1.47	1.31	1.60	1.84	1.55	1.85	1.79	1.85	1.91	1.94
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.03	0.03	0.73	-	-	-	-	-	-
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	12.91	12.76	12.87	13.39	14.51	6.67	6.58	7.06	4.78	5.67	5.37	5.62
LIQUIFIED NATURAL GAS FACILITIES - LNG	-	-	-	-	-	-	-	0.49	0.58	0.61	0.90	1.02
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-	2.07	0.93	1.29	3.57	3.91	4.34	5.13	6.27
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	-	-	-	-	1.16	0.30	3.22	2.27	4.01	4.90	5.21	5.80
STRATEGIC UNDERGROUND PLAN	1.84	1.40	1.40	2.14	2.49	1.99	4.17	4.63	4.01	4.48	4.84	4.92
RURAL BROADBAND	-	-	-	0.03	0.19	0.23	0.42	0.56	0.65	0.64	0.61	0.59
A5 Environmental												
RIDER E	1.99	1.99	1.67	1.25	1.95	2.03	1.35	0.68	0.75	0.61	0.67	0.79
RIDER CCR	-	-	-	2.95	2.96	2.38	1.19	3.13	3.13	3.13	3.14	4.22
RIDER RGGI	-	-	-	2.39	-	4.64	-	-	-	-	-	-
Additional Resources												
GAS CT	-	-	-	-	-	-	-	-	-	1.79	3.07	4.92
RPS Program-Related Resources												
RIDER RPS [5]	-	-	-	0.18	1.81	1.32	4.69	5.02	4.81	7.38	9.16	10.44
RIDER CE [6]	-	-	-	0.19	1.67	2.87	4.10	6.07	9.11	11.75	14.45	18.03
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.38)	(1.15)	(1.22)	(1.43)	(1.89)	(2.16)	(2.37)	(3.04)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(1.16)	(1.41)	(2.57)	(3.07)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.03)	(0.03)	-	(0.96)	(0.69)	(0.46)	(0.74)	(1.07)
TOTAL RIDER CE	**-**	**-**	**-**	**0.19**	**1.26**	**1.69**	**2.89**	**3.69**	**5.36**	**7.72**	**8.77**	**10.86**
RIDER OSW [7]	-	-	-	-	1.45	4.74	8.63	9.07	11.89	12.51	11.44	10.78
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	-	(2.43)	(3.34)	(3.13)	(3.11)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	-	(2.13)	(4.02)	(4.03)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	-	(0.99)	(1.54)	(1.40)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**1.45**	**4.74**	**8.63**	**9.07**	**9.46**	**6.05**	**2.75**	**2.24**
NUCLEAR SMALL MODULAR REACTORS [8]	-	-	-	-	-	-	-	0.07	0.41	1.43	1.43	1.43
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**0.37**	**4.52**	**7.75**	**16.21**	**17.84**	**20.05**	**22.59**	**22.10**	**24.96**
TOTAL	**122.66**	**116.18**	**116.54**	**122.72**	**140.22**	**134.16**	**140.18**	**151.13**	**161.51**	**170.41**	**177.26**	**189.67**

RESIDENTIAL Schedule 1 (1,000 kWh)	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]	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	-	-	-	-	-	-
TRANSMISSION - RIDER T	36.28	39.06	41.78	44.44	46.50	48.21	50.08	51.89	53.66	55.41
FUEL - RIDER A	34.51	34.40	35.02	36.65	38.61	39.42	42.41	46.09	51.17	54.98
FUEL SECURITIZATION	2.62	-	-	-	-	-	-	-	-	-
DSM	1.98	2.02	2.06	2.10	2.14	2.19	2.19	2.19	2.19	2.19
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	-	-	-	-	-	-	-
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	5.65	5.41	5.39	5.63	5.44	5.47	5.43	5.66	5.86	5.54
LIQUIFIED NATURAL GAS FACILITIES - LNG	0.99	0.98	0.95	0.92	0.90	0.87	0.85	0.83	0.80	0.78
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	7.46	7.99	8.39	8.38	8.34	8.15	7.88	7.58	7.28	6.98
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	6.00	5.82	5.66	5.49	5.25	5.06	4.84	4.65	4.49	4.32
STRATEGIC UNDERGROUND PLAN	5.01	4.69	4.59	4.49	4.38	4.28	4.17	4.07	3.98	3.88
RURAL BROADBAND	0.57	0.56	0.54	0.52	0.51	0.49	0.47	0.45	0.43	0.42
A5 Environmental										
RIDER E	0.77	0.62	0.46	0.54	0.51	0.49	0.47	0.45	0.43	0.40
RIDER CCR	4.42	4.45	3.76	5.09	4.05	4.03	1.50	0.30	0.46	0.19
RIDER RGGI	-	-	-	-	-	-	-	-	-	-
Additional Resources										
GAS CT	7.76	11.00	14.23	16.45	17.15	18.44	19.38	18.88	18.38	17.89
RPS Program-Related Resources										
RIDER RPS [5]	11.81	13.33	14.58	15.94	16.63	17.41	18.50	20.13	21.56	23.02
RIDER CE [6]	21.55	25.32	29.16	32.88	36.84	40.72	44.74	48.51	51.01	52.86
RIDER CE - FUEL BENEFIT	(3.60)	(3.78)	(3.76)	(4.15)	(4.51)	(4.80)	(5.53)	(6.26)	(7.05)	(7.82)
RIDER CE - REC PROXY VALUE	(4.09)	(5.01)	(5.70)	(6.23)	(6.64)	(6.96)	(7.18)	(7.56)	(7.83)	(8.05)
RIDER CE - CAPACITY OFFSET	(1.34)	(1.53)	(1.97)	(2.41)	(2.73)	(3.14)	(3.43)	(3.69)	(4.09)	(4.61)
TOTAL RIDER CE	**12.52**	**15.00**	**17.73**	**20.09**	**22.95**	**25.83**	**28.60**	**31.00**	**32.04**	**32.38**
RIDER OSW [7]	10.96	11.59	15.38	16.73	19.11	21.24	28.50	33.16	34.04	34.46
RIDER OSW - FUEL BENEFIT	(3.10)	(2.74)	(2.39)	(2.49)	(3.15)	(3.12)	(3.43)	(3.71)	(4.47)	(7.52)
RIDER OSW - REC PROXY VALUE	(4.01)	(4.01)	(3.80)	(3.61)	(3.49)	(4.16)	(3.89)	(3.74)	(3.56)	(3.66)
RIDER OSW - CAPACITY OFFSET	(1.28)	(1.22)	(1.29)	(1.19)	(1.15)	(1.22)	(1.28)	(1.34)	(1.40)	(2.19)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**2.56**	**3.61**	**7.90**	**9.45**	**11.33**	**12.74**	**19.90**	**24.38**	**24.61**	**21.10**
NUCLEAR SMALL MODULAR REACTORS [8]	1.38	5.80	8.84	12.41	15.99	18.89	21.22	22.56	23.14	22.08
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**28.27**	**37.74**	**49.05**	**57.89**	**66.90**	**74.87**	**88.21**	**98.07**	**101.35**	**98.57**
TOTAL	**202.99**	**215.46**	**232.60**	**249.31**	**261.40**	**272.69**	**288.60**	**301.84**	**311.19**	**312.27**
CAGR (2019 BASE)						5.1%				4.8%
CAGR (MAY 2020 BASE)						5.6%				5.2%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - REC RPS ONLY WITH EPA, 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
DISTRIBUTION & GENERATION (BASE) [1]	61.82	61.82	61.82	61.82	60.93	60.93	60.71	60.72	60.72	60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	(0.47)	(0.43)	-	-	-	-
TRANSMISSION - RIDER T	19.72	19.72	20.29	16.60	12.91	15.58	19.40	20.87	22.92	24.55
FUEL - RIDER A	23.25	17.36	17.02	20.45	35.38	28.59	20.74	23.56	28.08	25.50
FUEL SECURITIZATION	-	-	-	-	-	-	3.37	3.13	2.78	2.93
DSM	1.13	1.13	1.47	1.31	1.60	1.84	1.55	1.83	1.77	1.82
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.03	0.03	0.73	-	-	-	-
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	12.91	12.76	12.87	13.39	14.51	6.67	6.57	7.06	4.55	5.28
LIQUIFIED NATURAL GAS FACILITIES - LNG	-	-	-	-	-	-	-	0.49	0.55	0.57
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-	2.07	0.93	1.29	3.57	3.73	4.04
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	-	-	-	-	1.16	0.30	3.22	2.26	3.95	4.79
STRATEGIC UNDERGROUND PLAN	1.84	1.40	1.40	2.14	2.49	1.99	4.17	4.47	3.85	4.26
RURAL BROADBAND	-	-	-	0.03	0.19	0.23	0.42	0.56	0.65	0.63
A5 Environmental										
RIDER E [5]	1.99	1.99	1.67	1.25	1.95	2.03	1.35	0.68	0.84	1.76
RIDER CCR	-	-	-	2.95	2.96	2.38	1.19	3.13	3.05	3.01
RIDER RGGI	-	-	-	2.39	-	4.64	-	-	-	-
Additional Resources										
GAS CT	-	-	-	-	-	-	-	-	0.88	2.23
RPS Program-Related Resources										
RIDER RPS [6]	-	-	-	0.18	1.81	1.32	4.69	5.07	4.73	7.18
RIDER CE [7]	-	-	-	0.19	1.67	2.88	4.10	6.07	6.19	7.93
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.38)	(1.15)	(1.22)	(1.43)	(1.99)	(2.20)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(1.21)	(1.45)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.03)	(0.03)	-	(0.96)	(0.75)	(0.58)
TOTAL RIDER CE	**-**	**-**	**-**	**0.19**	**1.26**	**1.70**	**2.89**	**3.69**	**2.23**	**3.70**
RIDER OSW [8]	-	-	-	-	1.45	4.74	8.63	9.07	11.46	11.76
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	-	(2.32)	(3.12)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	-	(1.95)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	-	(1.23)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**1.45**	**4.74**	**8.63**	**9.07**	**9.15**	**5.46**
NUCLEAR SMALL MODULAR REACTORS [9]	-	-	-	-	-	-	-	0.07	0.39	1.33
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**0.37**	**4.52**	**7.76**	**16.21**	**17.89**	**16.50**	**17.67**
TOTAL	**122.66**	**116.18**	**116.54**	**122.72**	**140.22**	**134.17**	**140.18**	**150.21**	**154.81**	**159.76**
CAGR (2019 BASE)										
CAGR (MAY 2020 BASE)										

RESIDENTIAL Schedule 1 (1,000 kWh)	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	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039
DISTRIBUTION & GENERATION (BASE) [1]	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	-	-	-	-	-	-	-	-
TRANSMISSION - RIDER T	26.48	28.15	29.37	30.55	31.43	32.19	32.28	32.14	31.89	31.78	31.39	31.06
FUEL - RIDER A	26.03	26.55	29.12	30.06	31.77	32.16	32.99	32.00	33.05	33.76	35.25	36.61
FUEL SECURITIZATION	2.78	2.73	2.62	-	-	-	-	-	-	-	-	-
DSM	1.84	1.85	1.86	1.86	1.86	1.87	1.86	1.86	1.83	1.79	1.76	1.73
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	-	-	-	-	-	-	-	-	-
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	4.75	4.84	4.70	4.34	4.18	4.23	3.94	3.81	3.64	3.66	3.63	3.30
LIQUIFIED NATURAL GAS FACILITIES - LNG	0.79	0.88	0.82	0.78	0.73	0.69	0.64	0.60	0.56	0.53	0.49	0.46
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	4.54	5.40	6.20	6.40	6.49	6.27	5.99	5.63	5.22	4.85	4.47	4.11
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	5.03	5.54	5.63	5.37	5.12	4.89	4.57	4.32	4.03	3.82	3.61	3.42
STRATEGIC UNDERGROUND PLAN	4.54	4.57	4.58	4.22	4.04	3.88	3.71	3.55	3.38	3.25	3.11	2.99
RURAL BROADBAND	0.59	0.57	0.54	0.52	0.49	0.47	0.44	0.42	0.39	0.37	0.35	0.33
A5 Environmental												
RIDER E [5]	2.51	3.61	3.82	3.46	3.10	2.93	2.69	2.47	2.26	2.08	1.89	1.71
RIDER CCR	2.97	3.92	4.01	3.95	3.25	4.28	3.31	3.21	1.11	0.21	0.29	0.12
RIDER RGGI	-	-	-	-	-	-	-	-	-	-	-	-
Additional Resources												
GAS CT	3.14	4.79	6.70	8.74	10.91	12.23	12.23	12.66	12.75	11.99	11.21	10.47
RPS Program-Related Resources												
RIDER RPS [6]	8.73	9.76	10.81	11.93	12.47	13.02	12.90	12.84	12.44	12.74	12.46	12.57
RIDER CE [7]	8.86	10.64	12.27	13.93	15.53	17.18	18.88	20.60	21.95	23.31	23.72	23.88
RIDER CE - FUEL BENEFIT	(2.34)	(2.81)	(3.20)	(3.62)	(3.91)	(4.32)	(4.69)	(5.03)	(5.40)	(5.76)	(6.09)	(6.40)
RIDER CE - REC PROXY VALUE	(2.53)	(2.97)	(3.74)	(4.48)	(4.87)	(5.08)	(5.12)	(5.06)	(4.68)	(4.62)	(4.47)	(4.33)
RIDER CE - CAPACITY OFFSET	(1.05)	(1.68)	(2.28)	(2.73)	(3.23)	(3.76)	(4.06)	(4.42)	(4.69)	(4.94)	(5.14)	(5.35)
TOTAL RIDER CE	**2.94**	**3.18**	**3.04**	**3.11**	**3.52**	**4.03**	**5.01**	**6.09**	**7.17**	**8.00**	**8.02**	**7.79**
RIDER OSW [8]	10.24	9.23	8.75	9.50	14.12	12.24	14.88	17.88	21.35	22.66	21.24	20.09
RIDER OSW - FUEL BENEFIT	(2.83)	(2.73)	(2.63)	(2.44)	(2.25)	(2.14)	(2.03)	(1.93)	(2.25)	(4.04)	(4.18)	(4.78)
RIDER OSW - REC PROXY VALUE	(3.56)	(3.44)	(3.30)	(3.17)	(2.83)	(2.52)	(2.21)	(1.93)	(1.66)	(1.68)	(2.78)	(2.58)
RIDER OSW - CAPACITY OFFSET	(1.98)	(1.99)	(1.96)	(1.98)	(1.92)	(1.66)	(1.30)	(1.15)	(1.16)	(1.87)	(2.35)	(2.57)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**1.88**	**1.07**	**0.86**	**1.91**	**7.12**	**5.93**	**9.34**	**12.88**	**16.28**	**15.07**	**11.93**	**10.17**
NUCLEAR SMALL MODULAR REACTORS [9]	1.26	1.23	1.15	4.65	6.84	9.28	11.48	13.05	14.05	14.43	14.20	13.01
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**14.82**	**15.24**	**15.86**	**21.60**	**29.95**	**32.25**	**38.72**	**44.85**	**49.95**	**50.24**	**46.61**	**43.53**
TOTAL	**161.52**	**169.33**	**176.54**	**182.57**	**194.03**	**199.05**	**204.11**	**208.24**	**210.79**	**209.04**	**204.79**	**200.56**
CAGR (2019 BASE)								3.4%				2.5%
CAGR (MAY 2020 BASE)								3.8%				2.8%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - REC RPS ONLY WITH 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 92.87	$ 104.27	$ 111.76	$ 120.64	$ 126.60
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 141.38	$ 168.49	$ 152.98	$ 156.20	$ 159.28
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 18.81	$ 16.68	$ 17.57	$ 16.68	$ 16.40
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 8.82	$ 6.38	$ 7.47	$ 7.43	$ 7.81	$ 8.12	$ 8.31
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 33.69	$ 23.90	$ 28.35	$ 25.51	$ 25.69
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.35	$ 2.90	$ 3.05	$ 4.25	$ 4.65
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 17.02	$ 19.56	$ 21.67	$ 24.38	$ 28.68
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 4.73	$ 1.40	$ 10.89	$ 7.59	$ 13.70	$ 17.00	$ 18.32	$ 20.48
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18	$ 9.86	$ 8.26	$ 14.42	$ 17.26	$ 15.32	$ 17.37	$ 19.01	$ 19.40
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12	$ 0.82	$ 0.97	$ 1.52	$ 1.99	$ 2.36	$ 2.36	$ 2.27	$ 2.21
A5 Environmental												
RIDER E [5]	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.25	$ 4.40	$ 9.43	$ 13.51	$ 19.18
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.13	$ 18.79	$ 18.29	$ 18.08	$ 17.79	$ 23.49
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 27.85	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.61	$ 11.99	$ 16.86	$ 25.44
RPS Program-Related Resources												
RIDER RPS [6]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 30.39	$ 28.38	$ 43.08	$ 52.40	$ 58.57
RIDER CE [7]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.46	$ 17.97	$ 27.75	$ 31.57	$ 41.99	$ 47.26	$ 57.20
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.56)	$ (11.95)	$ (13.22)	$ (14.03)	$ (16.85)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7.27)	$ (8.69)	$ (15.17)	$ (17.81)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (3.77)	$ (3.01)	$ (5.39)	$ (8.55)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.75**	**$ 10.68**	**$ 14.90**	**$ 8.57**	**$ 17.08**	**$ 12.67**	**$ 13.99**
RIDER OSW [8]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 44.45	$ 57.37	$ 60.62	$ 52.57	$ 46.96
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13.90)	$ (18.71)	$ (16.97)	$ (16.37)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11.72)	$ (21.33)	$ (20.62)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.35)	$ (10.16)	$ (10.14)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 44.45**	**$ 43.48**	**$ 23.83**	**$ 4.11**	**$ (0.17)**
NUCLEAR SMALL MODULAR REACTORS [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.34	$ 2.06	$ 7.15	$ 6.80	$ 6.54
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.38**	**$ 74.18**	**$ 90.08**	**$ 82.49**	**$ 91.13**	**$ 75.98**	**$ 78.93**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 645.79**	**$ 646.48**	**$ 717.13**	**$ 749.01**	**$ 775.15**	**$ 784.11**	**$ 823.33**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
TRANSMISSION - RIDER T	$ 133.68	$ 138.03	$ 142.81	$ 145.33	$ 147.28	$ 146.90	$ 143.62	$ 142.92	$ 141.64	$ 142.57
FUEL - RIDER A	$ 174.71	$ 180.35	$ 190.63	$ 192.93	$ 197.95	$ 192.01	$ 198.32	$ 202.57	$ 211.52	$ 219.65
FUEL SECURITIZATION	$ 15.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
DSM	$ 8.56	$ 8.76	$ 8.99	$ 9.21	$ 9.50	$ 9.84	$ 9.83	$ 9.89	$ 9.96	$ 10.25
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 24.95	$ 23.15	$ 22.24	$ 22.51	$ 21.02	$ 20.60	$ 19.40	$ 19.19	$ 19.12	$ 17.72
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 4.37	$ 4.18	$ 3.91	$ 3.66	$ 3.43	$ 3.25	$ 3.01	$ 2.78	$ 2.60	$ 2.47
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 32.93	$ 34.15	$ 34.54	$ 33.34	$ 31.99	$ 30.43	$ 27.85	$ 25.46	$ 23.52	$ 22.09
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ 21.37	$ 20.80	$ 20.36	$ 19.85	$ 19.19	$ 18.78	$ 17.93	$ 17.35	$ 16.86	$ 16.71
STRATEGIC UNDERGROUND PLAN	$ 19.97	$ 18.74	$ 18.45	$ 18.11	$ 17.89	$ 17.74	$ 17.28	$ 16.97	$ 16.69	$ 16.77
RURAL BROADBAND	$ 2.17	$ 2.11	$ 2.06	$ 2.00	$ 1.96	$ 1.91	$ 1.84	$ 1.78	$ 1.73	$ 1.70
A5 Environmental										
RIDER E [5]	$ 20.29	$ 18.47	$ 16.49	$ 15.61	$ 14.38	$ 13.37	$ 12.06	$ 10.90	$ 9.95	$ 9.19
RIDER CCR	$ 24.05	$ 23.67	$ 19.48	$ 25.68	$ 19.88	$ 19.24	$ 6.64	$ 1.25	$ 1.76	$ 0.70
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Additional Resources										
GAS CT	$ 35.57	$ 46.58	$ 58.07	$ 65.04	$ 65.30	$ 68.42	$ 68.05	$ 62.98	$ 59.00	$ 56.24
RPS Program-Related Resources										
RIDER RPS [6]	$ 64.85	$ 71.59	$ 74.83	$ 78.13	$ 77.38	$ 77.02	$ 74.64	$ 76.46	$ 74.73	$ 75.40
RIDER CE [7]	$ 66.74	$ 76.59	$ 85.97	$ 95.59	$ 105.68	$ 116.35	$ 123.35	$ 130.21	$ 133.07	$ 135.61
RIDER CE - FUEL BENEFIT	$ (19.22)	$ (21.72)	$ (23.47)	$ (25.90)	$ (28.16)	$ (30.19)	$ (32.38)	$ (34.55)	$ (36.51)	$ (38.41)
RIDER CE - REC PROXY VALUE	$ (22.44)	$ (26.88)	$ (29.24)	$ (30.46)	$ (30.71)	$ (30.37)	$ (28.10)	$ (27.69)	$ (26.83)	$ (26.00)
RIDER CE - CAPACITY OFFSET	$ (11.60)	$ (13.94)	$ (16.53)	$ (19.25)	$ (20.91)	$ (23.09)	$ (24.29)	$ (25.23)	$ (26.35)	$ (28.09)
TOTAL RIDER CE	**$ 13.48**	**$ 14.05**	**$ 16.73**	**$ 19.98**	**$ 25.90**	**$ 32.69**	**$ 38.58**	**$ 42.74**	**$ 43.38**	**$ 43.10**
RIDER OSW [8]	$ 44.55	$ 48.60	$ 72.24	$ 62.76	$ 76.71	$ 93.60	$ 110.53	$ 115.70	$ 108.94	$ 105.46
RIDER OSW - FUEL BENEFIT	$ (15.78)	$ (14.64)	$ (13.51)	$ (12.83)	$ (12.18)	$ (11.57)	$ (13.49)	$ (24.21)	$ (25.05)	$ (28.67)
RIDER OSW - REC PROXY VALUE	$ (19.77)	$ (19.01)	$ (16.97)	$ (15.14)	$ (13.27)	$ (11.57)	$ (9.93)	$ (10.07)	$ (16.67)	$ (15.47)
RIDER OSW - CAPACITY OFFSET	$ (9.99)	$ (10.12)	$ (9.80)	$ (8.49)	$ (6.70)	$ (6.02)	$ (6.01)	$ (9.55)	$ (12.07)	$ (13.49)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (0.99)**	**$ 4.83**	**$ 31.96**	**$ 26.30**	**$ 44.56**	**$ 64.43**	**$ 81.11**	**$ 71.87**	**$ 55.15**	**$ 47.83**
NUCLEAR SMALL MODULAR REACTORS [9]	$ 6.10	$ 24.79	$ 36.38	$ 49.35	$ 61.33	$ 70.54	$ 74.99	$ 75.76	$ 74.75	$ 69.87
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 83.44**	**$ 115.26**	**$ 159.91**	**$ 173.77**	**$ 209.17**	**$ 244.68**	**$ 269.32**	**$ 266.83**	**$ 248.01**	**$ 236.20**
TOTAL	**$ 866.33**	**$ 898.84**	**$ 962.52**	**$ 991.60**	**$ 1,023.54**	**$ 1,051.77**	**$ 1,059.74**	**$ 1,045.46**	**$ 1,026.96**	**$ 1,016.85**
CAGR (2019 BASE)						3.9%				2.9%
CAGR (MAY 2020 BASE)						4.4%				3.3%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - REC RPS ONLY WITH 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	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (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	$ 72,000.00	$ 71,390.00	$ 84,040.00	$ 90,420.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 141,384.00	$ 168,486.00	$ 152,976.00	$ 156,204.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,226.00	$ 18,809.25	$ 16,684.83	$ 17,569.35	$ 16,679.55
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 360.00	$ 480.00	$ 474.00	$ 510.00	$ 498.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 17,920.00	$ 10,990.00	$ 12,660.00	$ 12,470.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,250.00	$ 1,330.00	$ 1,360.00	$ 2,080.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 9,040.00	$ 9,010.00	$ 9,680.00	$ 11,920.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1,160.00	$ 360.00	$ 2,670.00	$ 1,760.00	$ 2,660.00	$ 3,050.00	$ 3,020.00
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00	$ 130.00	$ 150.00	$ 230.00	$ 280.00	$ 280.00	$ 260.00	$ 230.00
A5 Environmental											
RIDER E [5]	$ 5,560.00	$ 5,560.00	$ 4,300.00	$ 3,140.00	$ 4,860.00	$ 4,440.00	$ 3,260.00	$ 1,730.00	$ 2,020.00	$ 4,210.00	$ 6,600.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,128.00	$ 18,786.00	$ 18,294.00	$ 18,078.00	$ 17,790.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 27,852.00	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,120.00	$ 5,360.00	$ 8,240.00
RPS Program-Related Resources											
RIDER RPS [6]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 30,390.00	$ 28,380.00	$ 43,080.00	$ 52,404.00
RIDER CE [7]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 15,162.00	$ 18,978.00	$ 26,220.00	$ 32,948.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (8,562.00)	$ (11,946.00)	$ (13,218.00)	$ (14,028.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,272.00)	$ (8,688.00)	$ (15,174.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (2,080.00)	$ (1,630.00)	$ (3,170.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,420.00**	**$ (2,320.00)**	**$ 2,684.00**	**$ 576.00**
RIDER OSW [8]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 23,730.00	$ 29,450.00	$ 30,050.00	$ 28,690.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,896.00)	$ (18,714.00)	$ (16,968.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,724.00)	$ (21,330.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,150.00)	$ (5,540.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 23,730.00**	**$ 15,554.00**	**$ (3,538.00)**	**$ (15,148.00)**
NUCLEAR SMALL MODULAR REACTORS [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180.00	$ 950.00	$ 3,190.00	$ 3,320.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 58,720.00**	**$ 42,564.00**	**$ 45,416.00**	**$ 41,152.00**
TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 434,195.69**	**$ 412,731.63**	**$ 465,721.96**	**$ 469,865.54**	**$ 478,732.06**	**$ 490,866.26**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

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]	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 96,600.00	$ 101,590.00	$ 106,320.00	$ 108,680.00	$ 111,920.00	$ 112,090.00	$ 111,500.00	$ 110,980.00	$ 110,090.00	$ 109,000.00	$ 108,170.00
FUEL - RIDER A	$ 159,282.00	$ 174,708.00	$ 180,348.00	$ 190,632.00	$ 192,930.00	$ 197,952.00	$ 192,012.00	$ 198,324.00	$ 202,572.00	$ 211,524.00	$ 219,654.00
FUEL SECURITIZATION	$ 16,399.86	$ 15,700.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 474.00	$ 456.00	$ 432.00	$ 414.00	$ 390.00	$ 372.00	$ 354.00	$ 294.00	$ 252.00	$ 222.00	$ 192.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 12,750.00	$ 12,540.00	$ 11,750.00	$ 11,310.00	$ 11,450.00	$ 10,690.00	$ 10,330.00	$ 9,880.00	$ 9,890.00	$ 9,860.00	$ 8,960.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 2,310.00	$ 2,200.00	$ 2,120.00	$ 1,990.00	$ 1,860.00	$ 1,750.00	$ 1,630.00	$ 1,530.00	$ 1,430.00	$ 1,340.00	$ 1,250.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 14,240.00	$ 16,560.00	$ 17,340.00	$ 17,560.00	$ 16,950.00	$ 16,270.00	$ 15,260.00	$ 14,180.00	$ 13,150.00	$ 12,100.00	$ 11,200.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ 3,140.00	$ 3,030.00	$ 2,760.00	$ 2,490.00	$ 2,260.00	$ 2,010.00	$ 1,800.00	$ 1,450.00	$ 1,190.00	$ 1,000.00	$ 850.00
RURAL BROADBAND	$ 210.00	$ 190.00	$ 170.00	$ 150.00	$ 140.00	$ 120.00	$ 110.00	$ 90.00	$ 70.00	$ 60.00	$ 50.00
A5 Environmental											
RIDER E [5]	$ 9,510.00	$ 10,210.00	$ 9,380.00	$ 8,380.00	$ 7,920.00	$ 7,310.00	$ 6,700.00	$ 6,150.00	$ 5,640.00	$ 5,120.00	$ 4,660.00
RIDER CCR	$ 23,490.00	$ 24,048.00	$ 23,670.00	$ 19,476.00	$ 25,680.00	$ 19,878.00	$ 19,242.00	$ 6,642.00	$ 1,254.00	$ 1,764.00	$ 702.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ 12,630.00	$ 17,890.00	$ 23,660.00	$ 29,520.00	$ 33,070.00	$ 33,210.00	$ 34,300.00	$ 34,630.00	$ 32,540.00	$ 30,360.00	$ 28,510.00
RPS Program-Related Resources											
RIDER RPS [6]	$ 58,572.00	$ 64,854.00	$ 71,592.00	$ 74,832.00	$ 78,132.00	$ 77,382.00	$ 77,016.00	$ 74,640.00	$ 76,464.00	$ 74,730.00	$ 75,396.00
RIDER CE [7]	$ 42,218.00	$ 51,320.00	$ 60,576.00	$ 69,232.00	$ 77,940.00	$ 86,952.00	$ 95,776.00	$ 99,050.00	$ 102,596.00	$ 106,360.00	$ 109,468.00
RIDER CE - FUEL BENEFIT	$ (16,848.00)	$ (19,224.00)	$ (21,720.00)	$ (23,466.00)	$ (25,896.00)	$ (28,164.00)	$ (30,186.00)	$ (32,382.00)	$ (34,548.00)	$ (36,510.00)	$ (38,412.00)
RIDER CE - REC PROXY VALUE	$ (17,808.00)	$ (22,440.00)	$ (26,880.00)	$ (29,244.00)	$ (30,456.00)	$ (30,708.00)	$ (30,372.00)	$ (28,104.00)	$ (27,690.00)	$ (26,826.00)	$ (26,004.00)
RIDER CE - CAPACITY OFFSET	$ (5,060.00)	$ (6,920.00)	$ (8,370.00)	$ (9,900.00)	$ (11,480.00)	$ (12,450.00)	$ (13,480.00)	$ (12,980.00)	$ (12,570.00)	$ (13,420.00)	$ (14,370.00)
TOTAL RIDER CE	**$ 2,502.00**	**$ 2,736.00**	**$ 3,606.00**	**$ 6,622.00**	**$ 10,108.00**	**$ 15,630.00**	**$ 21,738.00**	**$ 25,584.00**	**$ 27,788.00**	**$ 29,604.00**	**$ 30,682.00**
RIDER OSW [8]	$ 25,910.00	$ 24,890.00	$ 27,400.00	$ 40,680.00	$ 35,250.00	$ 43,010.00	$ 51,570.00	$ 61,670.00	$ 65,380.00	$ 61,170.00	$ 58,170.00
RIDER OSW - FUEL BENEFIT	$ (16,368.00)	$ (15,780.00)	$ (14,640.00)	$ (13,506.00)	$ (12,828.00)	$ (12,180.00)	$ (11,574.00)	$ (13,488.00)	$ (24,210.00)	$ (25,050.00)	$ (28,674.00)
RIDER OSW - REC PROXY VALUE	$ (20,622.00)	$ (19,770.00)	$ (19,014.00)	$ (16,968.00)	$ (15,138.00)	$ (13,266.00)	$ (11,568.00)	$ (9,930.00)	$ (10,068.00)	$ (16,674.00)	$ (15,468.00)
RIDER OSW - CAPACITY OFFSET	$ (5,590.00)	$ (5,580.00)	$ (5,700.00)	$ (5,520.00)	$ (4,770.00)	$ (3,760.00)	$ (3,320.00)	$ (3,350.00)	$ (5,390.00)	$ (6,780.00)	$ (7,450.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (16,670.00)**	**$ (16,240.00)**	**$ (11,954.00)**	**$ 4,686.00**	**$ 2,514.00**	**$ 13,804.00**	**$ 25,108.00**	**$ 34,902.00**	**$ 25,712.00**	**$ 12,666.00**	**$ 6,578.00**
NUCLEAR SMALL MODULAR REACTORS [9]	$ 3,250.00	$ 3,070.00	$ 12,590.00	$ 18,500.00	$ 25,090.00	$ 31,190.00	$ 35,360.00	$ 38,170.00	$ 39,140.00	$ 38,470.00	$ 35,420.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 47,654.00**	**$ 54,420.00**	**$ 75,834.00**	**$ 104,640.00**	**$ 115,844.00**	**$ 138,006.00**	**$ 159,222.00**	**$ 173,296.00**	**$ 169,104.00**	**$ 155,470.00**	**$ 148,076.00**
TOTAL	**$ 522,252.57**	**$ 557,105.25**	**$ 577,346.71**	**$ 618,804.71**	**$ 643,976.71**	**$ 663,220.71**	**$ 676,022.71**	**$ 681,008.71**	**$ 670,744.71**	**$ 661,382.71**	**$ 655,836.71**
CAGR (2019 BASE)							4.2%				3.2%
CAGR (MAY 2020 BASE)							5.0%				3.8%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - VCEA WITH EPA, 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
DISTRIBUTION & GENERATION (BASE) [1]	61.82	61.82	61.82	61.82	60.93	60.93	60.71	60.72	60.72	60.72	60.72	60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	(0.47)	(0.43)	-	-	-	-	-	-
TRANSMISSION - RIDER T	19.72	19.72	20.29	16.60	12.91	15.58	19.40	20.87	22.92	24.55	26.48	28.15
FUEL - RIDER A	23.25	17.36	17.02	20.45	35.38	28.59	20.74	23.56	28.27	26.45	26.99	27.30
FUEL SECURITIZATION	-	-	-	-	-	-	3.37	3.13	2.78	2.93	2.78	2.73
DSM	1.13	1.13	1.47	1.31	1.60	1.84	1.55	1.83	1.77	1.82	1.84	1.85
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.03	0.03	0.73	-	-	-	-	-	-
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	12.91	12.76	12.87	13.39	14.51	6.67	6.57	7.06	4.55	5.28	4.75	4.84
LIQUIFIED NATURAL GAS FACILITIES - LNG	-	-	-	-	-	-	-	0.49	0.55	0.57	0.79	0.88
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-	2.07	0.93	1.29	3.57	3.73	4.04	4.54	5.40
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	-	-	-	-	1.16	0.30	3.22	2.26	3.95	4.79	5.03	5.54
STRATEGIC UNDERGROUND PLAN	1.84	1.40	1.40	2.14	2.49	1.99	4.17	4.47	3.85	4.26	4.54	4.57
RURAL BROADBAND	-	-	-	0.03	0.19	0.23	0.42	0.56	0.65	0.63	0.59	0.57
A5 Environmental												
RIDER E [5]	1.99	1.99	1.67	1.25	1.95	2.03	1.35	0.68	0.84	1.76	2.51	3.61
RIDER CCR	-	-	-	2.95	2.96	2.38	1.19	3.13	3.05	3.01	2.97	3.92
RIDER RGGI	-	-	-	2.39	-	4.64	-	-	-	-	-	-
Additional Resources												
GAS CT	-	-	-	-	-	-	-	-	1.09	2.03	3.76	5.44
RPS Program-Related Resources												
RIDER RPS [6]	-	-	-	0.18	1.81	1.32	4.69	5.07	4.73	7.18	8.73	9.76
RIDER CE [7]	-	-	-	0.19	1.67	2.88	4.10	6.07	8.95	11.39	13.68	16.87
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.38)	(1.15)	(1.22)	(1.43)	(2.00)	(2.27)	(2.41)	(2.99)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(1.21)	(1.46)	(2.61)	(3.06)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.03)	(0.03)	-	(0.96)	(0.75)	(0.59)	(1.01)	(1.61)
TOTAL RIDER CE	**-**	**-**	**-**	**0.19**	**1.26**	**1.70**	**2.89**	**3.69**	**4.99**	**7.07**	**7.66**	**9.21**
RIDER OSW [8]	-	-	-	-	1.45	4.74	8.63	9.07	11.46	11.76	10.24	9.41
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	-	(2.32)	(3.12)	(2.83)	(2.73)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	-	(1.95)	(3.56)	(3.44)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	-	(1.23)	(1.98)	(1.99)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**1.45**	**4.74**	**8.63**	**9.07**	**9.15**	**5.46**	**1.88**	**1.25**
NUCLEAR SMALL MODULAR REACTORS [9]	-	-	-	-	-	-	-	0.07	0.39	1.33	1.26	1.23
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**0.37**	**4.52**	**7.76**	**16.21**	**17.89**	**19.25**	**21.04**	**19.54**	**21.45**
TOTAL	**122.66**	**116.18**	**116.54**	**122.72**	**140.22**	**134.17**	**140.18**	**150.21**	**157.95**	**163.87**	**167.82**	**176.94**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

RESIDENTIAL Schedule 1 (1,000 kWh)	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]	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	-	-	-	-	-	-
TRANSMISSION - RIDER T	29.37	30.55	31.43	32.19	32.28	32.14	31.89	31.78	31.39	31.06
FUEL - RIDER A	29.71	30.68	31.47	31.90	32.34	32.15	32.94	34.38	36.36	37.27
FUEL SECURITIZATION	2.62	-	-	-	-	-	-	-	-	-
DSM	1.86	1.86	1.86	1.87	1.86	1.86	1.83	1.79	1.76	1.73
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	-	-	-	-	-	-	-
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	4.70	4.34	4.18	4.23	3.94	3.81	3.64	3.66	3.63	3.30
LIQUIFIED NATURAL GAS FACILITIES - LNG	0.82	0.78	0.73	0.69	0.64	0.60	0.56	0.53	0.49	0.46
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	6.20	6.40	6.49	6.27	5.99	5.63	5.22	4.85	4.47	4.11
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	5.63	5.37	5.12	4.89	4.57	4.32	4.03	3.82	3.61	3.42
STRATEGIC UNDERGROUND PLAN	4.58	4.22	4.04	3.88	3.71	3.55	3.38	3.25	3.11	2.99
RURAL BROADBAND	0.54	0.52	0.49	0.47	0.44	0.42	0.39	0.37	0.35	0.33
A5 Environmental										
RIDER E [5]	3.82	3.46	3.10	2.93	2.69	2.47	2.26	2.08	1.89	1.71
RIDER CCR	4.01	3.95	3.25	4.28	3.31	3.21	1.11	0.21	0.29	0.12
RIDER RGGI	-	-	-	-	-	-	-	-	-	-
Additional Resources										
GAS CT	7.05	8.62	11.08	12.51	13.00	12.58	12.64	11.94	11.18	10.44
RPS Program-Related Resources										
RIDER RPS [6]	10.80	11.93	12.47	13.02	12.89	12.76	12.17	12.44	12.47	12.58
RIDER CE [7]	19.76	22.72	25.55	28.20	30.77	33.15	35.07	36.91	36.60	35.89
RIDER CE - FUEL BENEFIT	(3.41)	(3.85)	(4.18)	(4.62)	(5.04)	(5.41)	(5.82)	(6.22)	(6.59)	(6.94)
RIDER CE - REC PROXY VALUE	(3.98)	(4.77)	(5.19)	(5.42)	(5.48)	(5.44)	(5.04)	(4.98)	(4.83)	(4.69)
RIDER CE - CAPACITY OFFSET	(2.22)	(2.67)	(3.19)	(3.73)	(4.04)	(4.40)	(4.67)	(4.93)	(5.14)	(5.36)
TOTAL RIDER CE	**10.16**	**11.42**	**13.00**	**14.43**	**16.22**	**17.90**	**19.54**	**20.79**	**20.05**	**18.90**
RIDER OSW [8]	9.25	9.45	12.11	12.76	14.02	15.01	19.33	21.76	21.48	20.90
RIDER OSW - FUEL BENEFIT	(2.63)	(2.44)	(2.25)	(2.22)	(2.66)	(2.53)	(2.59)	(2.63)	(2.97)	(4.78)
RIDER OSW - REC PROXY VALUE	(3.30)	(3.17)	(2.83)	(2.52)	(2.28)	(2.52)	(2.17)	(2.00)	(1.82)	(1.79)
RIDER OSW - CAPACITY OFFSET	(1.96)	(1.98)	(1.92)	(1.66)	(1.51)	(1.51)	(1.52)	(1.53)	(1.54)	(2.24)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**1.36**	**1.86**	**5.12**	**6.36**	**7.58**	**8.46**	**13.06**	**15.60**	**15.16**	**12.09**
NUCLEAR SMALL MODULAR REACTORS [9]	1.15	4.65	6.84	9.28	11.48	13.05	14.05	14.43	14.20	13.01
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**23.47**	**29.86**	**37.42**	**43.09**	**48.17**	**52.16**	**58.82**	**63.25**	**61.89**	**56.58**
TOTAL	**185.10**	**191.34**	**201.37**	**209.91**	**213.67**	**215.62**	**219.43**	**222.61**	**221.15**	**214.24**
CAGR (2019 BASE)						3.59%				2.83%
CAGR (MAY 2020 BASE)						4.03%				3.16%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - VCEA WITH 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 92.87	$ 104.27	$ 111.76	$ 120.64	$ 126.60
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 141.38	$ 169.60	$ 158.68	$ 161.96	$ 163.77
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 18.81	$ 16.68	$ 17.57	$ 16.68	$ 16.40
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 8.82	$ 6.38	$ 7.47	$ 7.43	$ 7.81	$ 8.12	$ 8.31
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 33.69	$ 23.90	$ 28.35	$ 25.51	$ 25.69
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.35	$ 2.90	$ 3.05	$ 4.25	$ 4.65
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 17.02	$ 19.56	$ 21.67	$ 24.38	$ 28.68
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 4.73	$ 1.40	$ 10.89	$ 7.59	$ 13.70	$ 17.00	$ 18.32	$ 20.48
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18	$ 9.86	$ 8.26	$ 14.42	$ 17.26	$ 15.32	$ 17.37	$ 19.01	$ 19.40
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12	$ 0.82	$ 0.97	$ 1.52	$ 1.99	$ 2.36	$ 2.36	$ 2.27	$ 2.21
A5 Environmental												
RIDER E [5]	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.25	$ 4.40	$ 9.43	$ 13.51	$ 19.18
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.13	$ 18.79	$ 18.29	$ 18.08	$ 17.79	$ 23.49
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 27.85	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.71	$ 10.88	$ 20.18	$ 28.88
RPS Program-Related Resources												
RIDER RPS [6]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 30.39	$ 28.38	$ 43.07	$ 52.40	$ 58.56
RIDER CE [7]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.46	$ 17.97	$ 27.75	$ 45.37	$ 59.80	$ 72.01	$ 88.34
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.56)	$ (12.00)	$ (13.63)	$ (14.47)	$ (17.93)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7.27)	$ (8.73)	$ (15.65)	$ (18.37)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (3.77)	$ (3.05)	$ (5.15)	$ (8.18)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.75**	**$ 10.68**	**$ 14.90**	**$ 22.33**	**$ 34.39**	**$ 36.74**	**$ 43.86**
RIDER OSW [8]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 44.45	$ 57.37	$ 60.62	$ 52.57	$ 47.89
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13.90)	$ (18.71)	$ (16.97)	$ (16.37)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11.72)	$ (21.33)	$ (20.62)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.35)	$ (10.16)	$ (10.14)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 44.45**	**$ 43.48**	**$ 23.83**	**$ 4.11**	**$ 0.76**
NUCLEAR SMALL MODULAR REACTORS [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.34	$ 2.06	$ 7.15	$ 6.80	$ 6.54
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.38**	**$ 74.18**	**$ 90.08**	**$ 96.25**	**$ 108.44**	**$ 100.05**	**$ 109.72**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 645.79**	**$ 646.48**	**$ 717.13**	**$ 764.97**	**$ 797.04**	**$ 817.26**	**$ 862.05**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
TRANSMISSION - RIDER T	$ 133.68	$ 138.03	$ 142.81	$ 145.33	$ 147.28	$ 146.90	$ 143.62	$ 142.92	$ 141.64	$ 142.57
FUEL - RIDER A	$ 178.26	$ 184.09	$ 188.83	$ 191.40	$ 194.03	$ 192.91	$ 197.61	$ 206.27	$ 218.18	$ 223.62
FUEL SECURITIZATION	$ 15.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
DSM	$ 8.56	$ 8.76	$ 8.99	$ 9.21	$ 9.50	$ 9.84	$ 9.83	$ 9.89	$ 9.96	$ 10.25
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 24.95	$ 23.15	$ 22.24	$ 22.51	$ 21.02	$ 20.60	$ 19.40	$ 19.19	$ 19.12	$ 17.72
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 4.37	$ 4.18	$ 3.91	$ 3.66	$ 3.43	$ 3.25	$ 3.01	$ 2.78	$ 2.60	$ 2.47
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 32.93	$ 34.15	$ 34.54	$ 33.34	$ 31.99	$ 30.43	$ 27.85	$ 25.46	$ 23.52	$ 22.09
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ 21.37	$ 20.80	$ 20.36	$ 19.85	$ 19.19	$ 18.78	$ 17.93	$ 17.35	$ 16.86	$ 16.71
STRATEGIC UNDERGROUND PLAN	$ 19.97	$ 18.74	$ 18.45	$ 18.11	$ 17.89	$ 17.74	$ 17.28	$ 16.97	$ 16.69	$ 16.77
RURAL BROADBAND	$ 2.17	$ 2.11	$ 2.06	$ 2.00	$ 1.96	$ 1.91	$ 1.84	$ 1.78	$ 1.73	$ 1.70
A5 Environmental										
RIDER E [5]	$ 20.29	$ 18.47	$ 16.49	$ 15.61	$ 14.38	$ 13.37	$ 12.06	$ 10.90	$ 9.95	$ 9.19
RIDER CCR	$ 24.05	$ 23.67	$ 19.48	$ 25.68	$ 19.88	$ 19.24	$ 6.64	$ 1.25	$ 1.76	$ 0.70
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Additional Resources										
GAS CT	$ 37.43	$ 45.95	$ 59.00	$ 66.52	$ 69.44	$ 68.02	$ 67.47	$ 62.69	$ 58.84	$ 56.09
RPS Program-Related Resources										
RIDER RPS [6]	$ 64.82	$ 71.56	$ 74.79	$ 78.09	$ 77.33	$ 76.54	$ 73.03	$ 74.61	$ 74.84	$ 75.48
RIDER CE [7]	$ 103.82	$ 119.93	$ 135.14	$ 149.49	$ 164.01	$ 178.84	$ 187.61	$ 195.34	$ 194.68	$ 194.53
RIDER CE - FUEL BENEFIT	$ (20.46)	$ (23.12)	$ (25.05)	$ (27.73)	$ (30.24)	$ (32.48)	$ (34.91)	$ (37.33)	$ (39.53)	$ (41.62)
RIDER CE - REC PROXY VALUE	$ (23.89)	$ (28.61)	$ (31.13)	$ (32.51)	$ (32.87)	$ (32.62)	$ (30.25)	$ (29.86)	$ (28.98)	$ (28.15)
RIDER CE - CAPACITY OFFSET	$ (11.28)	$ (13.66)	$ (16.30)	$ (19.10)	$ (20.78)	$ (22.99)	$ (24.19)	$ (25.15)	$ (26.32)	$ (28.12)
TOTAL RIDER CE	**$ 48.20**	**$ 54.53**	**$ 62.66**	**$ 70.15**	**$ 80.12**	**$ 90.75**	**$ 98.26**	**$ 103.01**	**$ 99.85**	**$ 96.64**
RIDER OSW [8]	$ 47.11	$ 48.34	$ 61.97	$ 65.41	$ 72.31	$ 78.58	$ 100.12	$ 111.12	$ 110.20	$ 109.69
RIDER OSW - FUEL BENEFIT	$ (15.78)	$ (14.64)	$ (13.51)	$ (13.32)	$ (15.95)	$ (15.16)	$ (15.54)	$ (15.80)	$ (17.80)	$ (28.67)
RIDER OSW - REC PROXY VALUE	$ (19.77)	$ (19.01)	$ (16.97)	$ (15.14)	$ (13.68)	$ (15.14)	$ (13.00)	$ (11.97)	$ (10.89)	$ (10.72)
RIDER OSW - CAPACITY OFFSET	$ (9.99)	$ (10.12)	$ (9.80)	$ (8.49)	$ (7.79)	$ (7.89)	$ (7.87)	$ (7.82)	$ (7.88)	$ (11.76)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 1.57**	**$ 4.57**	**$ 21.70**	**$ 28.46**	**$ 34.89**	**$ 40.39**	**$ 63.71**	**$ 75.53**	**$ 73.63**	**$ 58.54**
NUCLEAR SMALL MODULAR REACTORS [9]	$ 6.10	$ 24.79	$ 36.38	$ 49.35	$ 61.33	$ 70.54	$ 74.99	$ 75.76	$ 74.75	$ 69.87
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 120.68**	**$ 155.45**	**$ 195.53**	**$ 226.06**	**$ 253.67**	**$ 278.22**	**$ 309.99**	**$ 328.90**	**$ 323.07**	**$ 300.53**
TOTAL	**$ 909.00**	**$ 942.14**	**$ 997.27**	**$ 1,043.85**	**$ 1,068.26**	**$ 1,085.80**	**$ 1,099.11**	**$ 1,110.95**	**$ 1,108.53**	**$ 1,085.00**
CAGR (2019 BASE)						4.1%				3.2%
CAGR (MAY 2020 BASE)						4.7%				3.7%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - VCEA WITH 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	122,053.63	123,562.71	123,562.71	123,562.71	123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	(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	72,000.00	71,390.00	84,040.00	90,420.00
FUEL - RIDER A	139,524.00	104,142.00	102,126.00	122,688.00	212,274.00	171,522.00	124,410.00	141,384.00	169,602.00	158,676.00	161,958.00
FUEL SECURITIZATION	-	-	-	-	-	-	20,226.00	18,809.25	16,684.83	17,569.35	16,679.55
DSM	150.00	150.00	144.00	60.00	102.00	168.00	360.00	480.00	474.00	510.00	498.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	162.00	162.00	4,392.00	-	-	-	-	-
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	36,670.00	34,070.00	33,750.00	34,570.00	36,660.00	15,480.00	15,390.00	17,920.00	10,990.00	12,660.00	12,470.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	-	-	-	-	-	-	-	1,250.00	1,330.00	1,360.00	2,080.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-	5,150.00	2,030.00	3,110.00	9,040.00	9,010.00	9,680.00	11,920.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	-	-	-	-	1,160.00	360.00	2,670.00	1,760.00	2,660.00	3,050.00	3,020.00
RURAL BROADBAND	-	-	-	20.00	130.00	150.00	230.00	280.00	280.00	260.00	230.00
A5 Environmental											
RIDER E [5]	5,560.00	5,560.00	4,300.00	3,140.00	4,860.00	4,440.00	3,260.00	1,730.00	2,020.00	4,210.00	6,600.00
RIDER CCR	-	-	-	17,670.00	17,730.00	14,256.00	7,128.00	18,786.00	18,294.00	18,078.00	17,790.00
RIDER RGGI	-	-	-	14,358.00	-	27,852.00	-	-	-	-	-
Additional Resources											
GAS CT	-	-	-	-	-	-	-	-	2,620.00	4,860.00	9,870.00
RPS Program-Related Resources											
RIDER RPS [6]	-	-	-	1,092.00	10,860.00	7,896.00	28,134.00	30,390.00	28,380.00	43,074.00	52,404.00
RIDER CE [7]	-	-	-	480.00	5,002.00	7,720.00	11,120.00	15,162.00	26,566.00	35,850.00	47,528.00
RIDER CE - FUEL BENEFIT	-	-	-	-	(2,286.00)	(6,102.00)	(7,290.00)	(8,562.00)	(12,000.00)	(13,632.00)	(14,466.00)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(7,272.00)	(8,730.00)	(15,648.00)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(80.00)	(74.00)	-	(2,180.00)	(2,080.00)	(1,650.00)	(3,030.00)
TOTAL RIDER CE	**-**	**-**	**-**	**480.00**	**2,636.00**	**1,544.00**	**3,830.00**	**4,420.00**	**5,214.00**	**11,838.00**	**14,384.00**
RIDER OSW [8]	-	-	-	-	3,470.00	10,780.00	20,750.00	23,730.00	29,450.00	30,050.00	28,690.00
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	-	(13,896.00)	(18,714.00)	(16,968.00)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	-	(11,724.00)	(21,330.00)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	-	(3,150.00)	(5,540.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**3,470.00**	**10,780.00**	**20,750.00**	**23,730.00**	**15,554.00**	**(3,538.00)**	**(15,148.00)**
NUCLEAR SMALL MODULAR REACTORS [9]	-	-	-	-	-	-	-	180.00	950.00	3,190.00	3,320.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**1,572.00**	**16,966.00**	**20,220.00**	**52,714.00**	**58,720.00**	**50,098.00**	**54,564.00**	**54,960.00**
TOTAL	**350,860.69**	**312,878.69**	**313,786.69**	**370,696.69**	**455,896.60**	**434,195.69**	**412,451.63**	**465,721.96**	**479,015.54**	**493,080.06**	**512,058.26**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

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]	123,562.71	123,562.71	123,562.71	123,562.71	123,562.71	123,562.71	123,562.71	123,562.71	123,562.71	123,562.71	123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	-	-	-	-	-	-	-
TRANSMISSION - RIDER T	96,600.00	101,590.00	106,320.00	108,680.00	111,920.00	112,090.00	111,500.00	110,980.00	110,090.00	109,000.00	108,170.00
FUEL - RIDER A	163,770.00	178,260.00	184,086.00	188,832.00	191,400.00	194,034.00	192,906.00	197,610.00	206,268.00	218,184.00	223,620.00
FUEL SECURITIZATION	16,399.86	15,700.54	-	-	-	-	-	-	-	-	-
DSM	474.00	456.00	432.00	414.00	390.00	372.00	354.00	294.00	252.00	222.00	192.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	-	-	-	-	-	-	-	-
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	12,750.00	12,540.00	11,750.00	11,310.00	11,450.00	10,690.00	10,330.00	9,880.00	9,890.00	9,860.00	8,960.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	2,310.00	2,200.00	2,120.00	1,990.00	1,860.00	1,750.00	1,630.00	1,530.00	1,430.00	1,340.00	1,250.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	14,240.00	16,560.00	17,340.00	17,560.00	16,950.00	16,270.00	15,260.00	14,180.00	13,150.00	12,100.00	11,200.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	3,140.00	3,030.00	2,760.00	2,490.00	2,260.00	2,010.00	1,800.00	1,450.00	1,190.00	1,000.00	850.00
RURAL BROADBAND	210.00	190.00	170.00	150.00	140.00	120.00	110.00	90.00	70.00	60.00	50.00
A5 Environmental											
RIDER E [5]	9,510.00	10,210.00	9,380.00	8,380.00	7,920.00	7,310.00	6,700.00	6,150.00	5,640.00	5,120.00	4,660.00
RIDER CCR	23,490.00	24,048.00	23,670.00	19,476.00	25,680.00	19,878.00	19,242.00	6,642.00	1,254.00	1,764.00	702.00
RIDER RGGI	-	-	-	-	-	-	-	-	-	-	-
Additional Resources											
GAS CT	14,330.00	18,830.00	23,330.00	30,000.00	33,830.00	35,310.00	34,090.00	34,340.00	32,390.00	30,270.00	28,440.00
RPS Program-Related Resources											
RIDER RPS [6]	58,560.00	64,824.00	71,556.00	74,790.00	78,090.00	77,328.00	76,542.00	73,032.00	74,610.00	74,844.00	75,480.00
RIDER CE [7]	59,224.00	70,642.00	82,402.00	93,018.00	103,002.00	113,142.00	122,116.00	120,992.00	120,700.00	122,838.00	123,880.00
RIDER CE - FUEL BENEFIT	(17,934.00)	(20,460.00)	(23,124.00)	(25,050.00)	(27,726.00)	(30,240.00)	(32,484.00)	(34,914.00)	(37,326.00)	(39,528.00)	(41,622.00)
RIDER CE - REC PROXY VALUE	(18,366.00)	(23,886.00)	(28,608.00)	(31,134.00)	(32,514.00)	(32,868.00)	(32,616.00)	(30,252.00)	(29,862.00)	(28,980.00)	(28,146.00)
RIDER CE - CAPACITY OFFSET	(4,850.00)	(6,720.00)	(8,190.00)	(9,750.00)	(11,370.00)	(12,360.00)	(13,420.00)	(12,920.00)	(12,520.00)	(13,410.00)	(14,390.00)
TOTAL RIDER CE	**18,074.00**	**19,576.00**	**22,480.00**	**27,084.00**	**31,392.00**	**37,674.00**	**43,596.00**	**42,906.00**	**40,992.00**	**40,920.00**	**39,722.00**
RIDER OSW [8]	26,420.00	26,320.00	27,250.00	34,900.00	36,740.00	40,540.00	43,290.00	55,860.00	62,800.00	61,870.00	60,500.00
RIDER OSW - FUEL BENEFIT	(16,368.00)	(15,780.00)	(14,640.00)	(13,506.00)	(13,320.00)	(15,948.00)	(15,156.00)	(15,540.00)	(15,804.00)	(17,802.00)	(28,674.00)
RIDER OSW - REC PROXY VALUE	(20,622.00)	(19,770.00)	(19,014.00)	(16,968.00)	(15,138.00)	(13,680.00)	(15,144.00)	(13,002.00)	(11,970.00)	(10,890.00)	(10,716.00)
RIDER OSW - CAPACITY OFFSET	(5,590.00)	(5,580.00)	(5,700.00)	(5,520.00)	(4,770.00)	(4,370.00)	(4,350.00)	(4,390.00)	(4,410.00)	(4,420.00)	(6,490.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**(16,160.00)**	**(14,810.00)**	**(12,104.00)**	**(1,094.00)**	**3,512.00**	**6,542.00**	**8,640.00**	**22,928.00**	**30,616.00**	**28,758.00**	**14,620.00**
NUCLEAR SMALL MODULAR REACTORS [9]	3,250.00	3,070.00	12,590.00	18,500.00	25,090.00	31,190.00	35,360.00	38,170.00	39,140.00	38,470.00	35,420.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**63,724.00**	**72,660.00**	**94,522.00**	**119,280.00**	**138,084.00**	**152,734.00**	**164,138.00**	**177,036.00**	**185,358.00**	**182,992.00**	**165,242.00**
TOTAL	**544,510.57**	**579,837.25**	**599,442.71**	**632,124.71**	**665,446.71**	**676,130.71**	**681,622.71**	**683,744.71**	**690,544.71**	**695,474.71**	**676,898.71**
CAGR (2019 BASE)							4.2%				3.3%
CAGR (MAY 2020 BASE)							5.1%				4.0%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - VCEA WITHOUT EPA, 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
DISTRIBUTION & GENERATION (BASE) [1]	61.82	61.82	61.82	61.82	60.93	60.93	60.71	60.72	60.72	60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	(0.47)	(0.43)	-	-	-	-
TRANSMISSION - RIDER T	19.72	19.72	20.29	16.60	12.91	15.58	19.40	20.87	22.92	24.55
FUEL - RIDER A	23.25	17.36	17.02	20.45	35.38	28.59	20.74	23.56	28.21	26.25
FUEL SECURITIZATION	-	-	-	-	-	-	3.37	3.13	2.78	2.93
DSM	1.13	1.13	1.47	1.31	1.60	1.84	1.55	1.83	1.77	1.82
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.03	0.03	0.73	-	-	-	-
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	12.91	12.76	12.87	13.39	14.51	6.67	6.57	7.06	4.55	5.28
LIQUIFIED NATURAL GAS FACILITIES - LNG	-	-	-	-	-	-	-	0.49	0.55	0.57
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-	2.07	0.93	1.29	3.57	3.73	4.04
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	-	-	-	-	1.16	0.30	3.22	2.26	3.95	4.79
STRATEGIC UNDERGROUND PLAN	1.84	1.40	1.40	2.14	2.49	1.99	4.17	4.47	3.85	4.26
RURAL BROADBAND	-	-	-	0.03	0.19	0.23	0.42	0.56	0.65	0.63
A5 Environmental										
RIDER E	1.99	1.99	1.67	1.25	1.95	2.03	1.35	0.68	0.71	0.57
RIDER CCR	-	-	-	2.95	2.96	2.38	1.19	3.13	3.05	3.01
RIDER RGGI	-	-	-	2.39	-	4.64	-	-	-	-
Additional Resources										
GAS CT	-	-	-	-	-	-	-	-	-	1.67
RPS Program-Related Resources										
RIDER RPS [5]	-	-	-	0.18	1.81	1.32	4.69	5.07	4.73	7.18
RIDER CE [6]	-	-	-	0.19	1.67	2.88	4.10	6.07	8.95	11.39
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.38)	(1.15)	(1.22)	(1.43)	(1.98)	(2.24)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(1.21)	(1.46)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.03)	(0.03)	-	(0.96)	(0.68)	(0.44)
TOTAL RIDER CE	**-**	**-**	**-**	**0.19**	**1.26**	**1.70**	**2.89**	**3.69**	**5.08**	**7.26**
RIDER OSW [7]	-	-	-	-	1.45	4.74	8.63	9.07	11.46	11.76
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	-	(2.30)	(3.07)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	-	(1.95)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	-	(0.93)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**-**	**-**	**-**	**-**	**1.45**	**4.74**	**8.63**	**9.07**	**9.17**	**5.82**
NUCLEAR SMALL MODULAR REACTORS [8]	-	-	-	-	-	-	-	0.07	0.39	1.33
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**0.37**	**4.52**	**7.76**	**16.21**	**17.89**	**19.37**	**21.58**
TOTAL	**122.66**	**116.18**	**116.54**	**122.72**	**140.22**	**134.17**	**140.18**	**150.21**	**156.79**	**162.68**
CAGR (2019 BASE)										
CAGR (MAY 2020 BASE)										

RESIDENTIAL Schedule 1 (1,000 kWh)	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	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039
DISTRIBUTION & GENERATION (BASE) [1]	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72	60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	-	-	-	-	-	-	-	-	-	-	-	-
TRANSMISSION - RIDER T	26.48	28.15	29.37	30.55	31.43	32.19	32.28	32.14	31.89	31.78	31.39	31.06
FUEL - RIDER A	26.71	27.11	28.51	27.51	26.85	27.15	27.44	26.82	27.51	28.66	30.40	31.24
FUEL SECURITIZATION	2.78	2.73	2.62	-	-	-	-	-	-	-	-	-
DSM	1.84	1.85	1.86	1.86	1.86	1.87	1.86	1.86	1.83	1.79	1.76	1.73
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	-	-	-	-	-	-	-	-	-
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	4.75	4.84	4.70	4.34	4.17	4.21	3.91	3.78	3.60	3.62	3.60	3.27
LIQUIFIED NATURAL GAS FACILITIES - LNG	0.79	0.88	0.82	0.78	0.73	0.69	0.64	0.60	0.56	0.53	0.49	0.46
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	4.54	5.40	6.20	6.40	6.49	6.27	5.99	5.63	5.22	4.85	4.47	4.11
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	5.03	5.54	5.63	5.37	5.12	4.89	4.57	4.32	4.03	3.82	3.61	3.42
STRATEGIC UNDERGROUND PLAN	4.54	4.57	4.58	4.22	4.04	3.88	3.71	3.55	3.38	3.25	3.11	2.99
RURAL BROADBAND	0.59	0.57	0.54	0.52	0.49	0.47	0.44	0.42	0.39	0.37	0.35	0.33
A5 Environmental												
RIDER E	0.59	0.68	0.64	0.50	0.36	0.40	0.37	0.34	0.31	0.29	0.27	0.24
RIDER CCR	2.97	3.92	4.01	3.95	3.25	4.28	3.31	3.21	1.11	0.21	0.29	0.12
RIDER RGGI	-	-	-	-	-	-	-	-	-	-	-	-
Additional Resources												
GAS CT	2.71	4.24	6.45	8.82	11.01	12.30	12.32	12.74	12.83	12.07	11.28	10.54
RPS Program-Related Resources												
RIDER RPS [5]	8.73	9.76	10.80	11.93	12.69	13.52	13.72	13.97	13.79	14.07	14.09	14.19
RIDER CE [6]	13.68	16.87	19.76	22.72	25.56	28.21	30.78	33.15	35.08	36.92	36.61	35.90
RIDER CE - FUEL BENEFIT	(2.41)	(3.03)	(3.51)	(3.61)	(3.48)	(3.75)	(3.96)	(4.10)	(4.39)	(4.66)	(4.90)	(5.13)
RIDER CE - REC PROXY VALUE	(2.61)	(3.06)	(3.98)	(4.77)	(5.28)	(5.63)	(5.83)	(5.94)	(5.70)	(5.63)	(5.45)	(5.29)
RIDER CE - CAPACITY OFFSET	(0.69)	(0.98)	(1.22)	(1.36)	(1.71)	(2.04)	(2.25)	(2.52)	(2.68)	(2.83)	(2.96)	(3.17)
TOTAL RIDER CE	**7.97**	**9.80**	**11.06**	**12.99**	**15.09**	**16.80**	**18.74**	**20.59**	**22.31**	**23.80**	**23.30**	**22.31**
RIDER OSW [7]	10.24	9.41	9.25	9.45	12.11	12.76	14.02	15.02	19.34	21.76	21.48	20.90
RIDER OSW - FUEL BENEFIT	(2.77)	(2.65)	(2.55)	(2.17)	(1.81)	(1.81)	(2.19)	(2.08)	(2.17)	(2.24)	(2.57)	(4.15)
RIDER OSW - REC PROXY VALUE	(3.56)	(3.44)	(3.30)	(3.17)	(2.88)	(2.62)	(2.43)	(2.76)	(2.46)	(2.26)	(2.05)	(2.02)
RIDER OSW - CAPACITY OFFSET	(1.38)	(1.22)	(1.08)	(1.00)	(1.01)	(0.91)	(0.84)	(0.86)	(0.87)	(0.88)	(0.88)	(1.33)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**2.54**	**2.10**	**2.33**	**3.11**	**6.41**	**7.42**	**8.57**	**9.31**	**13.84**	**16.39**	**15.98**	**13.41**
NUCLEAR SMALL MODULAR REACTORS [8]	1.26	1.23	1.15	4.65	6.84	9.28	11.48	13.05	14.05	14.43	14.20	13.01
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**20.51**	**22.88**	**25.34**	**32.67**	**41.02**	**47.02**	**52.51**	**56.92**	**63.99**	**68.68**	**67.57**	**62.92**
TOTAL	**165.54**	**174.06**	**181.98**	**188.21**	**197.53**	**206.34**	**210.08**	**213.04**	**217.38**	**220.64**	**219.31**	**213.15**
CAGR (2019 BASE)								3.5%				2.8%
CAGR (MAY 2020 BASE)								3.9%				3.1%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - VCEA 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 92.87	$ 104.27	$ 111.76	$ 120.64	$ 126.60
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 141.38	$ 169.23	$ 157.52	$ 160.27	$ 162.68
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 18.81	$ 16.68	$ 17.57	$ 16.68	$ 16.40
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 8.82	$ 6.38	$ 7.47	$ 7.43	$ 7.81	$ 8.12	$ 8.31
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 33.69	$ 23.90	$ 28.35	$ 25.51	$ 25.69
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.35	$ 2.90	$ 3.05	$ 4.25	$ 4.65
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 17.02	$ 19.56	$ 21.67	$ 24.38	$ 28.68
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 4.73	$ 1.40	$ 10.89	$ 7.59	$ 13.70	$ 17.00	$ 18.32	$ 20.48
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18	$ 9.86	$ 8.26	$ 14.42	$ 17.26	$ 15.32	$ 17.37	$ 19.01	$ 19.40
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12	$ 0.82	$ 0.97	$ 1.52	$ 1.99	$ 2.36	$ 2.36	$ 2.27	$ 2.21
A5 Environmental												
RIDER E	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.25	$ 3.72	$ 3.07	$ 3.17	$ 3.62
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.13	$ 18.79	$ 18.29	$ 18.08	$ 17.79	$ 23.49
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 27.85	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8.93	$ 14.57	$ 22.49
RPS Program-Related Resources												
RIDER RPS [5]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 30.39	$ 28.38	$ 43.07	$ 52.40	$ 58.56
RIDER CE [6]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.46	$ 17.97	$ 27.75	$ 45.37	$ 59.80	$ 72.01	$ 88.34
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.56)	$ (11.90)	$ (13.45)	$ (14.47)	$ (18.17)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7.27)	$ (8.73)	$ (15.65)	$ (18.37)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (3.40)	$ (2.27)	$ (3.56)	$ (5.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.75**	**$ 10.68**	**$ 14.90**	**$ 22.81**	**$ 35.35**	**$ 38.33**	**$ 46.81**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 44.45	$ 57.37	$ 60.62	$ 52.57	$ 47.89
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13.78)	$ (18.40)	$ (16.61)	$ (15.92)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11.72)	$ (21.33)	$ (20.62)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4.78)	$ (7.09)	$ (6.22)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 44.45**	**$ 43.60**	**$ 25.72**	**$ 7.53**	**$ 5.12**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.34	$ 2.06	$ 7.15	$ 6.80	$ 6.54
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.38**	**$ 74.18**	**$ 90.08**	**$ 96.85**	**$ 111.29**	**$ 105.07**	**$ 117.04**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 645.79**	**$ 646.48**	**$ 717.13**	**$ 758.81**	**$ 790.44**	**$ 804.65**	**$ 846.34**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
TRANSMISSION - RIDER T	$ 133.68	$ 138.03	$ 142.81	$ 145.33	$ 147.28	$ 146.90	$ 143.62	$ 142.92	$ 141.64	$ 142.57
FUEL - RIDER A	$ 171.05	$ 165.03	$ 161.12	$ 162.91	$ 164.65	$ 160.93	$ 165.05	$ 171.98	$ 182.41	$ 187.43
FUEL SECURITIZATION	$ 15.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
DSM	$ 8.56	$ 8.76	$ 8.99	$ 9.21	$ 9.50	$ 9.84	$ 9.83	$ 9.89	$ 9.96	$ 10.25
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 24.95	$ 23.15	$ 22.20	$ 22.40	$ 20.87	$ 20.41	$ 19.18	$ 18.98	$ 18.94	$ 17.54
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 4.37	$ 4.18	$ 3.91	$ 3.66	$ 3.43	$ 3.25	$ 3.01	$ 2.78	$ 2.60	$ 2.47
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 32.93	$ 34.15	$ 34.54	$ 33.34	$ 31.99	$ 30.43	$ 27.85	$ 25.46	$ 23.52	$ 22.09
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ 21.37	$ 20.80	$ 20.36	$ 19.85	$ 19.19	$ 18.78	$ 17.93	$ 17.35	$ 16.86	$ 16.71
STRATEGIC UNDERGROUND PLAN	$ 19.97	$ 18.74	$ 18.45	$ 18.11	$ 17.89	$ 17.74	$ 17.28	$ 16.97	$ 16.69	$ 16.77
RURAL BROADBAND	$ 2.17	$ 2.11	$ 2.06	$ 2.00	$ 1.96	$ 1.91	$ 1.84	$ 1.78	$ 1.73	$ 1.70
A5 Environmental										
RIDER E	$ 3.39	$ 2.66	$ 1.91	$ 2.13	$ 1.97	$ 1.84	$ 1.67	$ 1.51	$ 1.40	$ 1.27
RIDER CCR	$ 24.05	$ 23.67	$ 19.48	$ 25.68	$ 19.88	$ 19.24	$ 6.64	$ 1.25	$ 1.76	$ 0.70
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Additional Resources										
GAS CT	$ 34.23	$ 47.03	$ 58.59	$ 65.44	$ 65.78	$ 68.87	$ 68.48	$ 63.38	$ 59.38	$ 56.60
RPS Program-Related Resources										
RIDER RPS [5]	$ 64.82	$ 71.56	$ 76.12	$ 81.13	$ 82.30	$ 83.80	$ 82.75	$ 84.40	$ 84.54	$ 85.15
RIDER CE [6]	$ 103.83	$ 119.93	$ 135.16	$ 149.51	$ 164.05	$ 178.88	$ 187.66	$ 195.39	$ 194.72	$ 194.59
RIDER CE - FUEL BENEFIT	$ (21.04)	$ (21.63)	$ (20.88)	$ (22.47)	$ (23.78)	$ (24.59)	$ (26.32)	$ (27.95)	$ (29.42)	$ (30.79)
RIDER CE - REC PROXY VALUE	$ (23.89)	$ (28.61)	$ (31.69)	$ (33.76)	$ (34.97)	$ (35.66)	$ (34.22)	$ (33.76)	$ (32.69)	$ (31.72)
RIDER CE - CAPACITY OFFSET	$ (6.20)	$ (6.92)	$ (8.73)	$ (10.46)	$ (11.60)	$ (13.18)	$ (13.87)	$ (14.44)	$ (15.18)	$ (16.60)
TOTAL RIDER CE	**$ 52.71**	**$ 62.78**	**$ 73.86**	**$ 82.82**	**$ 93.70**	**$ 105.45**	**$ 113.24**	**$ 119.24**	**$ 117.44**	**$ 115.47**
RIDER OSW [7]	$ 47.11	$ 48.34	$ 61.97	$ 65.41	$ 72.31	$ 78.59	$ 100.12	$ 111.13	$ 110.20	$ 109.70
RIDER OSW - FUEL BENEFIT	$ (15.29)	$ (13.03)	$ (10.85)	$ (10.87)	$ (13.12)	$ (12.46)	$ (13.03)	$ (13.43)	$ (15.43)	$ (24.87)
RIDER OSW - REC PROXY VALUE	$ (19.77)	$ (19.01)	$ (17.27)	$ (15.73)	$ (14.56)	$ (16.58)	$ (14.73)	$ (13.54)	$ (12.29)	$ (12.10)
RIDER OSW - CAPACITY OFFSET	$ (5.50)	$ (5.11)	$ (5.19)	$ (4.65)	$ (4.34)	$ (4.51)	$ (4.50)	$ (4.48)	$ (4.53)	$ (6.96)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 6.55**	**$ 11.20**	**$ 28.67**	**$ 34.16**	**$ 40.29**	**$ 45.04**	**$ 67.87**	**$ 79.67**	**$ 77.95**	**$ 65.77**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 6.10	$ 24.79	$ 36.38	$ 49.35	$ 61.33	$ 70.54	$ 74.99	$ 75.76	$ 74.75	$ 69.87
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 130.18**	**$ 170.32**	**$ 215.03**	**$ 247.46**	**$ 277.61**	**$ 304.82**	**$ 338.84**	**$ 359.06**	**$ 354.68**	**$ 336.26**
TOTAL	**$ 891.17**	**$ 923.22**	**$ 974.02**	**$ 1,022.10**	**$ 1,046.60**	**$ 1,069.56**	**$ 1,085.81**	**$ 1,097.91**	**$ 1,096.17**	**$ 1,076.96**
CAGR (2019 BASE)						4.0%				3.2%
CAGR (MAY 2020 BASE)						4.6%				3.6%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - VCEA 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 127,019.69	$ 127,019.69	$ 122,053.63	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (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	$ 72,000.00	$ 71,390.00	$ 84,040.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 141,384.00	$ 169,230.00	$ 157,524.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,226.00	$ 18,809.25	$ 16,684.83	$ 17,569.35
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 360.00	$ 480.00	$ 474.00	$ 510.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ -	$ -
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 17,920.00	$ 10,990.00	$ 12,660.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,250.00	$ 1,330.00	$ 1,360.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 9,040.00	$ 9,010.00	$ 9,680.00
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1,160.00	$ 360.00	$ 2,670.00	$ 1,760.00	$ 2,660.00	$ 3,050.00
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00	$ 130.00	$ 150.00	$ 230.00	$ 280.00	$ 280.00	$ 260.00
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	$ 1,730.00	$ 1,710.00	$ 1,370.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,128.00	$ 18,786.00	$ 18,294.00	$ 18,078.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 27,852.00	$ -	$ -	$ -	$ -
Additional Resources										
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,990.00
RPS Program-Related Resources										
RIDER RPS [5]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 30,390.00	$ 28,380.00	$ 43,074.00
RIDER CE [6]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 15,162.00	$ 26,566.00	$ 35,850.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (8,562.00)	$ (11,898.00)	$ (13,446.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,272.00)	$ (8,730.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (1,860.00)	$ (1,220.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,420.00**	**$ 5,536.00**	**$ 12,454.00**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 23,730.00	$ 29,450.00	$ 30,050.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,776.00)	$ (18,402.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,724.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,370.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 23,730.00**	**$ 15,674.00**	**$ (2,446.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180.00	$ 950.00	$ 3,190.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 58,720.00**	**$ 50,540.00**	**$ 56,272.00**
TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 434,195.69**	**$ 412,451.63**	**$ 465,721.96**	**$ 476,155.54**	**$ 489,926.06**
CAGR (2019 BASE)										
CAGR (MAY 2020 BASE)										

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	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	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039
DISTRIBUTION & GENERATION (BASE) [1]	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 90,420.00	$ 96,600.00	$ 101,590.00	$ 106,320.00	$ 108,680.00	$ 111,920.00	$ 112,090.00	$ 111,500.00	$ 110,980.00	$ 110,090.00	$ 109,000.00	$ 108,170.00
FUEL - RIDER A	$ 160,272.00	$ 162,684.00	$ 171,048.00	$ 165,030.00	$ 161,118.00	$ 162,906.00	$ 164,646.00	$ 160,926.00	$ 165,054.00	$ 171,984.00	$ 182,412.00	$ 187,434.00
FUEL SECURITIZATION	$ 16,679.55	$ 16,399.86	$ 15,700.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 498.00	$ 474.00	$ 456.00	$ 432.00	$ 414.00	$ 390.00	$ 372.00	$ 354.00	$ 294.00	$ 252.00	$ 222.00	$ 192.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 12,470.00	$ 12,750.00	$ 12,540.00	$ 11,750.00	$ 11,280.00	$ 11,400.00	$ 10,620.00	$ 10,240.00	$ 9,770.00	$ 9,790.00	$ 9,760.00	$ 8,890.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 2,080.00	$ 2,310.00	$ 2,200.00	$ 2,120.00	$ 1,990.00	$ 1,860.00	$ 1,750.00	$ 1,630.00	$ 1,530.00	$ 1,430.00	$ 1,340.00	$ 1,250.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 11,920.00	$ 14,240.00	$ 16,560.00	$ 17,340.00	$ 17,560.00	$ 16,950.00	$ 16,270.00	$ 15,260.00	$ 14,180.00	$ 13,150.00	$ 12,100.00	$ 11,200.00
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ 3,020.00	$ 3,140.00	$ 3,030.00	$ 2,760.00	$ 2,490.00	$ 2,260.00	$ 2,010.00	$ 1,800.00	$ 1,450.00	$ 1,190.00	$ 1,000.00	$ 850.00
RURAL BROADBAND	$ 230.00	$ 210.00	$ 190.00	$ 170.00	$ 150.00	$ 140.00	$ 120.00	$ 110.00	$ 90.00	$ 70.00	$ 60.00	$ 50.00
A5 Environmental												
RIDER E	$ 1,550.00	$ 1,800.00	$ 1,710.00	$ 1,350.00	$ 970.00	$ 1,070.00	$ 1,000.00	$ 920.00	$ 860.00	$ 790.00	$ 720.00	$ 640.00
RIDER CCR	$ 17,790.00	$ 23,490.00	$ 24,048.00	$ 23,670.00	$ 19,476.00	$ 25,680.00	$ 19,878.00	$ 19,242.00	$ 6,642.00	$ 1,254.00	$ 1,764.00	$ 702.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ 7,120.00	$ 11,170.00	$ 17,220.00	$ 23,890.00	$ 29,790.00	$ 33,270.00	$ 33,450.00	$ 34,520.00	$ 34,850.00	$ 32,750.00	$ 30,560.00	$ 28,690.00
RPS Program-Related Resources												
RIDER RPS [5]	$ 52,404.00	$ 58,560.00	$ 64,824.00	$ 71,556.00	$ 76,116.00	$ 81,126.00	$ 82,302.00	$ 83,802.00	$ 82,746.00	$ 84,396.00	$ 84,540.00	$ 85,152.00
RIDER CE [6]	$ 47,538.00	$ 59,224.00	$ 70,642.00	$ 82,402.00	$ 93,038.00	$ 103,012.00	$ 113,152.00	$ 122,136.00	$ 121,022.00	$ 120,730.00	$ 122,868.00	$ 123,910.00
RIDER CE - FUEL BENEFIT	$ (14,466.00)	$ (18,168.00)	$ (21,036.00)	$ (21,630.00)	$ (20,880.00)	$ (22,470.00)	$ (23,778.00)	$ (24,594.00)	$ (26,322.00)	$ (27,954.00)	$ (29,418.00)	$ (30,792.00)
RIDER CE - REC PROXY VALUE	$ (15,648.00)	$ (18,366.00)	$ (23,886.00)	$ (28,608.00)	$ (31,686.00)	$ (33,756.00)	$ (34,968.00)	$ (35,658.00)	$ (34,224.00)	$ (33,762.00)	$ (32,688.00)	$ (31,722.00)
RIDER CE - CAPACITY OFFSET	$ (2,090.00)	$ (2,960.00)	$ (3,700.00)	$ (4,170.00)	$ (5,230.00)	$ (6,240.00)	$ (6,900.00)	$ (7,700.00)	$ (7,400.00)	$ (7,180.00)	$ (7,720.00)	$ (8,500.00)
TOTAL RIDER CE	**$ 15,334.00**	**$ 19,730.00**	**$ 22,020.00**	**$ 27,994.00**	**$ 35,242.00**	**$ 40,546.00**	**$ 47,506.00**	**$ 54,184.00**	**$ 53,076.00**	**$ 51,834.00**	**$ 53,042.00**	**$ 52,896.00**
RIDER OSW [7]	$ 28,690.00	$ 26,420.00	$ 26,320.00	$ 27,250.00	$ 34,900.00	$ 36,740.00	$ 40,540.00	$ 43,300.00	$ 55,870.00	$ 62,800.00	$ 61,880.00	$ 60,510.00
RIDER OSW - FUEL BENEFIT	$ (16,614.00)	$ (15,918.00)	$ (15,294.00)	$ (13,026.00)	$ (10,848.00)	$ (10,872.00)	$ (13,116.00)	$ (12,456.00)	$ (13,026.00)	$ (13,434.00)	$ (15,426.00)	$ (24,870.00)
RIDER OSW - REC PROXY VALUE	$ (21,330.00)	$ (20,622.00)	$ (19,770.00)	$ (19,014.00)	$ (17,268.00)	$ (15,726.00)	$ (14,562.00)	$ (16,584.00)	$ (14,730.00)	$ (13,542.00)	$ (12,294.00)	$ (12,096.00)
RIDER OSW - CAPACITY OFFSET	$ (3,870.00)	$ (3,430.00)	$ (3,070.00)	$ (2,880.00)	$ (2,920.00)	$ (2,610.00)	$ (2,440.00)	$ (2,490.00)	$ (2,510.00)	$ (2,530.00)	$ (2,540.00)	$ (3,840.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (13,124.00)**	**$ (13,550.00)**	**$ (11,814.00)**	**$ (7,670.00)**	**$ 3,864.00**	**$ 7,532.00**	**$ 10,422.00**	**$ 11,770.00**	**$ 25,604.00**	**$ 33,294.00**	**$ 31,620.00**	**$ 19,704.00**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 3,320.00	$ 3,250.00	$ 3,070.00	$ 12,590.00	$ 18,500.00	$ 25,090.00	$ 31,190.00	$ 35,360.00	$ 38,170.00	$ 39,140.00	$ 38,470.00	$ 35,420.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 57,934.00**	**$ 67,990.00**	**$ 78,100.00**	**$ 104,470.00**	**$ 133,722.00**	**$ 154,294.00**	**$ 171,420.00**	**$ 185,116.00**	**$ 199,596.00**	**$ 208,664.00**	**$ 207,672.00**	**$ 193,172.00**
TOTAL	**$ 505,546.26**	**$ 536,820.57**	**$ 567,955.25**	**$ 582,864.71**	**$ 611,202.71**	**$ 645,702.71**	**$ 657,188.71**	**$ 665,180.71**	**$ 668,858.71**	**$ 674,976.71**	**$ 680,172.71**	**$ 664,802.71**
CAGR (2019 BASE)								4.1%				3.2%
CAGR (MAY 2020 BASE)								4.9%				3.9%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - REC RPS ONLY WITHOUT EPA, 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 60.93	$ 60.93	$ 60.71	$ 60.72	$ 60.72	$ 60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (0.47)	$ (0.43)	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	$ 12.91	$ 15.58	$ 19.40	$ 20.87	$ 22.92	$ 24.55
FUEL - RIDER A	$ 23.25	$ 17.36	$ 17.02	$ 20.45	$ 35.38	$ 28.59	$ 20.74	$ 23.56	$ 28.02	$ 25.31
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.37	$ 3.13	$ 2.78	$ 2.93
DSM	$ 1.13	$ 1.13	$ 1.47	$ 1.31	$ 1.60	$ 1.84	$ 1.55	$ 1.83	$ 1.77	$ 1.82
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.03	$ 0.03	$ 0.73	$ -	$ -	$ -	$ -
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	$ 14.51	$ 6.67	$ 6.57	$ 7.06	$ 4.55	$ 5.28
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.49	$ 0.55	$ 0.57
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 2.07	$ 0.93	$ 1.29	$ 3.57	$ 3.73	$ 4.04
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1.16	$ 0.30	$ 3.22	$ 2.26	$ 3.95	$ 4.79
STRATEGIC UNDERGROUND PLAN	$ 1.84	$ 1.40	$ 1.40	$ 2.14	$ 2.49	$ 1.99	$ 4.17	$ 4.47	$ 3.85	$ 4.26
RURAL BROADBAND	$ -	$ -	$ -	$ 0.03	$ 0.19	$ 0.23	$ 0.42	$ 0.56	$ 0.65	$ 0.63
A5 Environmental										
RIDER E	$ 1.99	$ 1.99	$ 1.67	$ 1.25	$ 1.95	$ 2.03	$ 1.35	$ 0.68	$ 0.71	$ 0.57
RIDER CCR	$ -	$ -	$ -	$ 2.95	$ 2.96	$ 2.38	$ 1.19	$ 3.13	$ 3.05	$ 3.01
RIDER RGGI	$ -	$ -	$ -	$ 2.39	$ -	$ 4.64	$ -	$ -	$ -	$ -
Additional Resources										
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.67
RPS Program-Related Resources										
RIDER RPS [5]	$ -	$ -	$ -	$ 0.18	$ 1.81	$ 1.32	$ 4.69	$ 5.07	$ 4.73	$ 7.18
RIDER CE [6]	$ -	$ -	$ -	$ 0.19	$ 1.67	$ 2.88	$ 4.10	$ 6.07	$ 6.19	$ 7.93
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.38)	$ (1.15)	$ (1.22)	$ (1.43)	$ (1.97)	$ (2.17)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.21)	$ (1.45)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.03)	$ (0.03)	$ -	$ (0.96)	$ (0.68)	$ (0.44)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 1.26**	**$ 1.70**	**$ 2.89**	**$ 3.69**	**$ 2.33**	**$ 3.88**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 1.45	$ 4.74	$ 8.63	$ 9.07	$ 11.46	$ 11.76
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.30)	$ (3.07)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.95)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.93)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.45**	**$ 4.74**	**$ 8.63**	**$ 9.07**	**$ 9.17**	**$ 5.82**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.07	$ 0.39	$ 1.33
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 4.52**	**$ 7.76**	**$ 16.21**	**$ 17.89**	**$ 16.62**	**$ 18.20**
TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.54**	**$ 122.72**	**$ 140.22**	**$ 134.17**	**$ 140.18**	**$ 150.21**	**$ 153.85**	**$ 158.35**
CAGR (2019 BASE)										
CAGR (MAY 2020 BASE)										

RESIDENTIAL Schedule 1 (1,000 kWh)	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	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039
DISTRIBUTION & GENERATION (BASE) [1]	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
TRANSMISSION - RIDER T	$ 26.48	$ 28.15	$ 29.37	$ 30.55	$ 31.43	$ 32.19	$ 32.28	$ 32.14	$ 31.89	$ 31.78	$ 31.39	$ 31.06
FUEL - RIDER A	$ 25.75	$ 26.36	$ 27.89	$ 26.87	$ 26.24	$ 26.50	$ 27.05	$ 26.53	$ 27.21	$ 28.49	$ 30.02	$ 30.72
FUEL SECURITIZATION	$ 2.78	$ 2.73	$ 2.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
DSM	$ 1.84	$ 1.85	$ 1.86	$ 1.86	$ 1.86	$ 1.87	$ 1.86	$ 1.86	$ 1.83	$ 1.79	$ 1.76	$ 1.73
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 4.75	$ 4.84	$ 4.70	$ 4.34	$ 4.17	$ 4.21	$ 3.91	$ 3.78	$ 3.60	$ 3.62	$ 3.60	$ 3.27
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 0.79	$ 0.88	$ 0.82	$ 0.78	$ 0.73	$ 0.69	$ 0.64	$ 0.60	$ 0.56	$ 0.53	$ 0.49	$ 0.46
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 4.54	$ 5.40	$ 6.20	$ 6.40	$ 6.49	$ 6.27	$ 5.99	$ 5.63	$ 5.22	$ 4.85	$ 4.47	$ 4.11
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ 5.03	$ 5.54	$ 5.63	$ 5.37	$ 5.12	$ 4.89	$ 4.57	$ 4.32	$ 4.03	$ 3.82	$ 3.61	$ 3.42
STRATEGIC UNDERGROUND PLAN	$ 4.54	$ 4.57	$ 4.58	$ 4.22	$ 4.04	$ 3.88	$ 3.71	$ 3.55	$ 3.38	$ 3.25	$ 3.11	$ 2.99
RURAL BROADBAND	$ 0.59	$ 0.57	$ 0.54	$ 0.52	$ 0.49	$ 0.47	$ 0.44	$ 0.42	$ 0.39	$ 0.37	$ 0.35	$ 0.33
A5 Environmental												
RIDER E	$ 0.59	$ 0.68	$ 0.64	$ 0.50	$ 0.36	$ 0.40	$ 0.37	$ 0.34	$ 0.31	$ 0.29	$ 0.27	$ 0.24
RIDER CCR	$ 2.97	$ 3.92	$ 4.01	$ 3.95	$ 3.25	$ 4.28	$ 3.31	$ 3.21	$ 1.11	$ 0.21	$ 0.29	$ 0.12
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Additional Resources												
GAS CT	$ 2.71	$ 4.24	$ 6.45	$ 8.82	$ 11.01	$ 12.30	$ 12.32	$ 12.74	$ 12.83	$ 12.07	$ 11.28	$ 10.54
RPS Program-Related Resources												
RIDER RPS [5]	$ 8.73	$ 9.76	$ 10.81	$ 11.93	$ 12.69	$ 13.53	$ 13.73	$ 14.04	$ 14.02	$ 14.50	$ 14.69	$ 14.45
RIDER CE [6]	$ 8.85	$ 10.62	$ 12.24	$ 13.90	$ 15.49	$ 17.13	$ 18.82	$ 20.54	$ 21.86	$ 23.21	$ 23.60	$ 23.76
RIDER CE - FUEL BENEFIT	$ (2.34)	$ (2.84)	$ (3.29)	$ (3.39)	$ (3.26)	$ (3.50)	$ (3.69)	$ (3.81)	$ (4.07)	$ (4.31)	$ (4.53)	$ (4.74)
RIDER CE - REC PROXY VALUE	$ (2.53)	$ (2.97)	$ (3.74)	$ (4.48)	$ (4.96)	$ (5.27)	$ (5.44)	$ (5.54)	$ (5.30)	$ (5.22)	$ (5.04)	$ (4.88)
RIDER CE - CAPACITY OFFSET	$ (0.59)	$ (0.93)	$ (1.25)	$ (1.38)	$ (1.73)	$ (2.06)	$ (2.27)	$ (2.53)	$ (2.69)	$ (2.84)	$ (2.96)	$ (3.16)
TOTAL RIDER CE	**$ 3.40**	**$ 3.88**	**$ 3.96**	**$ 4.65**	**$ 5.54**	**$ 6.30**	**$ 7.42**	**$ 8.66**	**$ 9.80**	**$ 10.84**	**$ 11.07**	**$ 10.98**
RIDER OSW [7]	$ 10.24	$ 9.23	$ 8.34	$ 7.65	$ 9.09	$ 9.00	$ 10.32	$ 12.64	$ 18.47	$ 22.02	$ 22.47	$ 21.65
RIDER OSW - FUEL BENEFIT	$ (2.77)	$ (2.65)	$ (2.55)	$ (2.17)	$ (1.81)	$ (1.74)	$ (1.67)	$ (1.59)	$ (1.66)	$ (1.79)	$ (2.57)	$ (4.15)
RIDER OSW - REC PROXY VALUE	$ (3.56)	$ (3.44)	$ (3.30)	$ (3.17)	$ (2.88)	$ (2.62)	$ (2.35)	$ (2.11)	$ (1.88)	$ (1.72)	$ (1.61)	$ (2.02)
RIDER OSW - CAPACITY OFFSET	$ (1.38)	$ (1.22)	$ (1.08)	$ (1.00)	$ (1.01)	$ (0.91)	$ (0.72)	$ (0.66)	$ (0.66)	$ (0.67)	$ (0.80)	$ (1.33)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 2.54**	**$ 1.91**	**$ 1.42**	**$ 1.31**	**$ 3.39**	**$ 3.73**	**$ 5.58**	**$ 8.28**	**$ 14.27**	**$ 17.84**	**$ 17.49**	**$ 14.16**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 1.26	$ 1.23	$ 1.15	$ 4.65	$ 6.84	$ 9.28	$ 11.48	$ 13.05	$ 14.05	$ 14.43	$ 14.20	$ 13.01
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 15.94**	**$ 16.78**	**$ 17.33**	**$ 22.54**	**$ 28.45**	**$ 32.84**	**$ 38.21**	**$ 44.03**	**$ 52.14**	**$ 57.60**	**$ 57.45**	**$ 52.60**
TOTAL	**$ 160.01**	**$ 167.21**	**$ 173.35**	**$ 177.44**	**$ 184.35**	**$ 191.51**	**$ 195.40**	**$ 199.86**	**$ 205.22**	**$ 209.37**	**$ 208.81**	**$ 202.31**
CAGR (2019 BASE)								3.1%				2.5%
CAGR (MAY 2020 BASE)								3.5%				2.9%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - REC RPS ONLY 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 92.87	$ 104.27	$ 111.76	$ 120.64	$ 126.60
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 141.38	$ 168.11	$ 151.84	$ 154.52	$ 158.17
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 18.81	$ 16.68	$ 17.57	$ 16.68	$ 16.40
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 8.82	$ 6.38	$ 7.47	$ 7.43	$ 7.81	$ 8.12	$ 8.31
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 33.69	$ 23.90	$ 28.35	$ 25.51	$ 25.69
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.35	$ 2.90	$ 3.05	$ 4.25	$ 4.65
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 17.02	$ 19.56	$ 21.67	$ 24.38	$ 28.68
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 4.73	$ 1.40	$ 10.89	$ 7.59	$ 13.70	$ 17.00	$ 18.32	$ 20.48
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18	$ 9.86	$ 8.26	$ 14.42	$ 17.26	$ 15.32	$ 17.37	$ 19.01	$ 19.40
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12	$ 0.82	$ 0.97	$ 1.52	$ 1.99	$ 2.36	$ 2.36	$ 2.27	$ 2.21
A5 Environmental												
RIDER E	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.25	$ 3.72	$ 3.07	$ 3.17	$ 3.62
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.13	$ 18.79	$ 18.29	$ 18.08	$ 17.79	$ 23.49
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 27.85	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8.93	$ 14.57	$ 22.49
RPS Program-Related Resources												
RIDER RPS [5]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 30.39	$ 28.38	$ 43.08	$ 52.40	$ 58.57
RIDER CE [6]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.46	$ 17.97	$ 27.75	$ 31.57	$ 41.98	$ 47.24	$ 57.16
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.56)	$ (11.84)	$ (13.04)	$ (14.02)	$ (17.06)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7.27)	$ (8.69)	$ (15.17)	$ (17.81)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (3.40)	$ (2.24)	$ (3.01)	$ (4.75)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.75**	**$ 10.68**	**$ 14.90**	**$ 9.06**	**$ 18.01**	**$ 15.04**	**$ 17.54**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 44.45	$ 57.37	$ 60.62	$ 52.57	$ 46.96
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13.78)	$ (18.40)	$ (16.61)	$ (15.92)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11.72)	$ (21.33)	$ (20.62)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4.78)	$ (7.09)	$ (6.22)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 44.45**	**$ 43.60**	**$ 25.72**	**$ 7.53**	**$ 4.19**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.34	$ 2.06	$ 7.15	$ 6.80	$ 6.54
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.38**	**$ 74.18**	**$ 90.08**	**$ 83.10**	**$ 93.95**	**$ 81.77**	**$ 86.85**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 645.79**	**$ 646.48**	**$ 717.13**	**$ 743.95**	**$ 767.41**	**$ 775.60**	**$ 811.64**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
TRANSMISSION - RIDER T	$ 133.68	$ 138.03	$ 142.81	$ 145.33	$ 147.28	$ 146.90	$ 143.62	$ 142.92	$ 141.64	$ 142.57
FUEL - RIDER A	$ 167.35	$ 161.23	$ 157.43	$ 158.99	$ 162.32	$ 159.20	$ 163.23	$ 170.92	$ 180.11	$ 184.33
FUEL SECURITIZATION	$ 15.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 8.56	$ 8.76	$ 8.99	$ 9.21	$ 9.50	$ 9.84	$ 9.83	$ 9.89	$ 9.96	$ 10.25
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 24.95	$ 23.15	$ 22.20	$ 22.40	$ 20.87	$ 20.41	$ 19.18	$ 18.98	$ 18.94	$ 17.54
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 4.37	$ 4.18	$ 3.91	$ 3.66	$ 3.43	$ 3.25	$ 3.01	$ 2.78	$ 2.60	$ 2.47
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 32.93	$ 34.15	$ 34.54	$ 33.34	$ 31.99	$ 30.43	$ 27.85	$ 25.46	$ 23.52	$ 22.09
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ 21.37	$ 20.80	$ 20.36	$ 19.85	$ 19.19	$ 18.78	$ 17.93	$ 17.35	$ 16.86	$ 16.71
STRATEGIC UNDERGROUND PLAN	$ 19.97	$ 18.74	$ 18.45	$ 18.11	$ 17.89	$ 17.74	$ 17.28	$ 16.97	$ 16.69	$ 16.77
RURAL BROADBAND	$ 2.17	$ 2.11	$ 2.06	$ 2.00	$ 1.96	$ 1.91	$ 1.84	$ 1.78	$ 1.73	$ 1.70
A5 Environmental										
RIDER E	$ 3.39	$ 2.66	$ 1.91	$ 2.13	$ 1.97	$ 1.84	$ 1.67	$ 1.51	$ 1.40	$ 1.27
RIDER CCR	$ 24.05	$ 23.67	$ 19.48	$ 25.68	$ 19.88	$ 19.24	$ 6.64	$ 1.25	$ 1.76	$ 0.70
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
GAS CT	$ 34.23	$ 47.03	$ 58.59	$ 65.44	$ 65.78	$ 68.87	$ 68.48	$ 63.38	$ 59.38	$ 56.60
RPS Program-Related Resources										
RIDER RPS [5]	$ 64.85	$ 71.59	$ 76.16	$ 81.17	$ 82.37	$ 84.24	$ 84.11	$ 86.98	$ 88.15	$ 86.72
RIDER CE [6]	$ 66.69	$ 76.52	$ 85.88	$ 95.45	$ 105.55	$ 116.15	$ 123.10	$ 129.89	$ 132.68	$ 135.16
RIDER CE - FUEL BENEFIT	$ (19.76)	$ (20.32)	$ (19.57)	$ (20.99)	$ (22.15)	$ (22.86)	$ (24.42)	$ (25.88)	$ (27.18)	$ (28.42)
RIDER CE - REC PROXY VALUE	$ (22.44)	$ (26.88)	$ (29.77)	$ (31.63)	$ (32.66)	$ (33.21)	$ (31.79)	$ (31.30)	$ (30.26)	$ (29.30)
RIDER CE - CAPACITY OFFSET	$ (6.37)	$ (7.06)	$ (8.86)	$ (10.55)	$ (11.69)	$ (13.24)	$ (13.94)	$ (14.48)	$ (15.19)	$ (16.58)
TOTAL RIDER CE	**$ 18.11**	**$ 22.27**	**$ 27.68**	**$ 32.29**	**$ 39.04**	**$ 46.85**	**$ 52.94**	**$ 58.22**	**$ 60.05**	**$ 60.85**
RIDER OSW [7]	$ 42.46	$ 39.12	$ 46.51	$ 46.12	$ 53.23	$ 66.14	$ 95.62	$ 112.46	$ 115.28	$ 113.65
RIDER OSW - FUEL BENEFIT	$ (15.29)	$ (13.03)	$ (10.85)	$ (10.43)	$ (10.02)	$ (9.52)	$ (9.95)	$ (10.76)	$ (15.43)	$ (24.87)
RIDER OSW - REC PROXY VALUE	$ (19.77)	$ (19.01)	$ (17.27)	$ (15.73)	$ (14.12)	$ (12.67)	$ (11.25)	$ (10.34)	$ (9.68)	$ (12.10)
RIDER OSW - CAPACITY OFFSET	$ (5.50)	$ (5.11)	$ (5.19)	$ (4.65)	$ (3.72)	$ (3.44)	$ (3.44)	$ (3.42)	$ (4.10)	$ (6.96)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 1.90**	**$ 1.97**	**$ 13.20**	**$ 15.31**	**$ 25.37**	**$ 40.51**	**$ 70.99**	**$ 87.94**	**$ 86.06**	**$ 69.72**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 6.10	$ 24.79	$ 36.38	$ 49.35	$ 61.33	$ 70.54	$ 74.99	$ 75.76	$ 74.75	$ 69.87
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 90.96**	**$ 120.62**	**$ 153.43**	**$ 178.12**	**$ 208.10**	**$ 242.14**	**$ 283.03**	**$ 308.90**	**$ 309.01**	**$ 287.16**
TOTAL	**$ 848.25**	**$ 869.72**	**$ 908.73**	**$ 948.84**	**$ 974.76**	**$ 1,005.15**	**$ 1,028.17**	**$ 1,046.68**	**$ 1,048.20**	**$ 1,024.75**
CAGR (2019 BASE)	3.6%					3.6%				2.9%
CAGR (MAY 2020 BASE)						4.1%				3.4%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
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LARGE GENERAL BILL PROJECTION - REC RPS ONLY 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	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (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	$ 72,000.00	$ 71,390.00	$ 84,040.00	$ 90,420.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 141,384.00	$ 168,114.00	$ 151,836.00	$ 154,524.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,226.00	$ 18,809.25	$ 16,684.83	$ 17,569.35	$ 16,679.55
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 360.00	$ 480.00	$ 474.00	$ 510.00	$ 498.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 17,920.00	$ 10,990.00	$ 12,660.00	$ 12,470.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,250.00	$ 1,330.00	$ 1,360.00	$ 2,080.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 9,040.00	$ 9,010.00	$ 9,680.00	$ 11,920.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1,160.00	$ 360.00	$ 2,670.00	$ 1,760.00	$ 2,660.00	$ 3,050.00	$ 3,020.00
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00	$ 130.00	$ 150.00	$ 230.00	$ 280.00	$ 280.00	$ 260.00	$ 230.00
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	$ 1,730.00	$ 1,710.00	$ 1,370.00	$ 1,550.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,128.00	$ 18,786.00	$ 18,294.00	$ 18,078.00	$ 17,790.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 27,852.00	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,990.00	$ 7,120.00
RPS Program-Related Resources											
RIDER RPS [5]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 30,390.00	$ 28,380.00	$ 43,080.00	$ 52,404.00
RIDER CE [6]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 15,162.00	$ 18,984.00	$ 26,236.00	$ 32,992.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (8,562.00)	$ (11,844.00)	$ (13,038.00)	$ (14,022.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,272.00)	$ (8,688.00)	$ (15,174.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (1,860.00)	$ (1,200.00)	$ (1,770.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,420.00**	**$ (1,992.00)**	**$ 3,310.00**	**$ 2,026.00**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 23,730.00	$ 29,450.00	$ 30,050.00	$ 28,690.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,776.00)	$ (18,402.00)	$ (16,614.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,724.00)	$ (21,330.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,370.00)	$ (3,870.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 23,730.00**	**$ 15,674.00**	**$ (2,446.00)**	**$ (13,124.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180.00	$ 950.00	$ 3,190.00	$ 3,320.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 58,720.00**	**$ 43,012.00**	**$ 47,134.00**	**$ 44,626.00**
TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 434,195.69**	**$ 412,731.63**	**$ 465,721.96**	**$ 467,511.54**	**$ 475,100.06**	**$ 486,490.26**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

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]	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 96,600.00	$ 101,590.00	$ 106,320.00	$ 108,680.00	$ 111,920.00	$ 112,090.00	$ 111,500.00	$ 110,980.00	$ 110,090.00	$ 109,000.00	$ 108,170.00
FUEL - RIDER A	$ 158,172.00	$ 167,346.00	$ 161,226.00	$ 157,434.00	$ 158,988.00	$ 162,324.00	$ 159,204.00	$ 163,230.00	$ 170,916.00	$ 180,114.00	$ 184,326.00
FUEL SECURITIZATION	$ 16,399.86	$ 15,700.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 474.00	$ 456.00	$ 432.00	$ 414.00	$ 390.00	$ 372.00	$ 354.00	$ 294.00	$ 252.00	$ 222.00	$ 192.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 12,750.00	$ 12,540.00	$ 11,750.00	$ 11,280.00	$ 11,400.00	$ 10,620.00	$ 10,240.00	$ 9,770.00	$ 9,790.00	$ 9,760.00	$ 8,890.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 2,310.00	$ 2,200.00	$ 2,120.00	$ 1,990.00	$ 1,860.00	$ 1,750.00	$ 1,630.00	$ 1,530.00	$ 1,430.00	$ 1,340.00	$ 1,250.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 14,240.00	$ 16,560.00	$ 17,340.00	$ 17,560.00	$ 16,950.00	$ 16,270.00	$ 15,260.00	$ 14,180.00	$ 13,150.00	$ 12,100.00	$ 11,200.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ 3,140.00	$ 3,030.00	$ 2,760.00	$ 2,490.00	$ 2,260.00	$ 2,010.00	$ 1,800.00	$ 1,450.00	$ 1,190.00	$ 1,000.00	$ 850.00
RURAL BROADBAND	$ 210.00	$ 190.00	$ 170.00	$ 150.00	$ 140.00	$ 120.00	$ 110.00	$ 90.00	$ 70.00	$ 60.00	$ 50.00
A5 Environmental											
RIDER E	$ 1,800.00	$ 1,710.00	$ 1,350.00	$ 970.00	$ 1,070.00	$ 1,000.00	$ 920.00	$ 860.00	$ 790.00	$ 720.00	$ 640.00
RIDER CCR	$ 23,490.00	$ 24,048.00	$ 23,670.00	$ 19,476.00	$ 25,680.00	$ 19,878.00	$ 19,242.00	$ 6,642.00	$ 1,254.00	$ 1,764.00	$ 702.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ 11,170.00	$ 17,220.00	$ 23,890.00	$ 29,790.00	$ 33,270.00	$ 33,450.00	$ 34,520.00	$ 34,850.00	$ 32,750.00	$ 30,560.00	$ 28,690.00
RPS Program-Related Resources											
RIDER RPS [5]	$ 58,572.00	$ 64,854.00	$ 71,592.00	$ 76,158.00	$ 81,174.00	$ 82,368.00	$ 84,240.00	$ 84,114.00	$ 86,976.00	$ 88,146.00	$ 86,718.00
RIDER CE [6]	$ 42,304.00	$ 51,468.00	$ 60,766.00	$ 69,492.00	$ 78,236.00	$ 87,290.00	$ 96,168.00	$ 99,512.00	$ 103,138.00	$ 106,894.00	$ 109,994.00
RIDER CE - FUEL BENEFIT	$ (17,064.00)	$ (19,764.00)	$ (20,316.00)	$ (19,572.00)	$ (20,994.00)	$ (22,152.00)	$ (22,860.00)	$ (24,420.00)	$ (25,878.00)	$ (27,180.00)	$ (28,422.00)
RIDER CE - REC PROXY VALUE	$ (17,808.00)	$ (22,440.00)	$ (26,880.00)	$ (29,766.00)	$ (31,626.00)	$ (32,664.00)	$ (33,210.00)	$ (31,794.00)	$ (31,302.00)	$ (30,264.00)	$ (29,304.00)
RIDER CE - CAPACITY OFFSET	$ (2,820.00)	$ (3,810.00)	$ (4,260.00)	$ (5,310.00)	$ (6,310.00)	$ (6,960.00)	$ (7,730.00)	$ (7,440.00)	$ (7,210.00)	$ (7,730.00)	$ (8,480.00)
TOTAL RIDER CE	**$ 4,612.00**	**$ 5,454.00**	**$ 9,310.00**	**$ 14,844.00**	**$ 19,306.00**	**$ 25,514.00**	**$ 32,368.00**	**$ 35,858.00**	**$ 38,748.00**	**$ 41,720.00**	**$ 43,788.00**
RIDER OSW [7]	$ 25,910.00	$ 23,720.00	$ 22,050.00	$ 26,190.00	$ 25,900.00	$ 29,840.00	$ 36,440.00	$ 53,360.00	$ 63,560.00	$ 64,730.00	$ 62,680.00
RIDER OSW - FUEL BENEFIT	$ (15,918.00)	$ (15,294.00)	$ (13,026.00)	$ (10,848.00)	$ (10,434.00)	$ (10,020.00)	$ (9,516.00)	$ (9,948.00)	$ (10,758.00)	$ (15,426.00)	$ (24,870.00)
RIDER OSW - REC PROXY VALUE	$ (20,622.00)	$ (19,770.00)	$ (19,014.00)	$ (17,268.00)	$ (15,726.00)	$ (14,124.00)	$ (12,666.00)	$ (11,250.00)	$ (10,344.00)	$ (9,684.00)	$ (12,096.00)
RIDER OSW - CAPACITY OFFSET	$ (3,430.00)	$ (3,070.00)	$ (2,880.00)	$ (2,920.00)	$ (2,610.00)	$ (2,090.00)	$ (1,900.00)	$ (1,920.00)	$ (1,930.00)	$ (2,300.00)	$ (3,840.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (14,060.00)**	**$ (14,414.00)**	**$ (12,870.00)**	**$ (4,846.00)**	**$ (2,870.00)**	**$ 3,606.00**	**$ 12,358.00**	**$ 30,242.00**	**$ 40,528.00**	**$ 37,320.00**	**$ 21,874.00**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 3,250.00	$ 3,070.00	$ 12,590.00	$ 18,500.00	$ 25,090.00	$ 31,190.00	$ 35,360.00	$ 38,170.00	$ 39,140.00	$ 38,470.00	$ 35,420.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 52,374.00**	**$ 58,964.00**	**$ 80,622.00**	**$ 104,656.00**	**$ 122,700.00**	**$ 142,678.00**	**$ 164,326.00**	**$ 188,384.00**	**$ 205,392.00**	**$ 205,656.00**	**$ 187,800.00**
TOTAL	**$ 516,692.57**	**$ 545,117.25**	**$ 555,212.71**	**$ 578,452.71**	**$ 610,190.71**	**$ 626,124.71**	**$ 642,668.71**	**$ 655,822.71**	**$ 670,636.71**	**$ 675,858.71**	**$ 656,322.71**
CAGR (2019 BASE)							3.9%				3.2%
CAGR (MAY 2020 BASE)							4.7%				3.8%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - REC RPS ONLY WITH EPA, 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 60.93	$ 60.93	$ 60.71	$ 60.72	$ 60.72	$ 60.72	$ 60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (0.47)	$ (0.43)	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	$ 12.91	$ 15.58	$ 19.40	$ 21.62	$ 24.31	$ 27.39	$ 30.50
FUEL - RIDER A	$ 23.25	$ 17.36	$ 17.02	$ 20.45	$ 35.38	$ 28.59	$ 20.74	$ 23.56	$ 29.91	$ 27.93	$ 29.56
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.37	$ 3.13	$ 2.78	$ 2.93	$ 2.78
DSM	$ 1.13	$ 1.13	$ 1.47	$ 1.31	$ 1.60	$ 1.84	$ 1.55	$ 1.85	$ 1.79	$ 1.85	$ 1.91
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.03	$ 0.03	$ 0.73	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	$ 14.51	$ 6.67	$ 6.58	$ 7.06	$ 4.78	$ 5.67	$ 5.37
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.49	$ 0.58	$ 0.61	$ 0.90
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 2.07	$ 0.93	$ 1.29	$ 3.57	$ 3.91	$ 4.34	$ 5.13
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1.16	$ 0.30	$ 3.22	$ 2.27	$ 4.01	$ 4.90	$ 5.21
STRATEGIC UNDERGROUND PLAN	$ 1.84	$ 1.40	$ 1.40	$ 2.14	$ 2.49	$ 1.99	$ 4.17	$ 4.63	$ 4.01	$ 4.48	$ 4.84
RURAL BROADBAND	$ -	$ -	$ -	$ 0.03	$ 0.19	$ 0.23	$ 0.42	$ 0.56	$ 0.65	$ 0.64	$ 0.61
A5 Environmental											
RIDER E [5]	$ 1.99	$ 1.99	$ 1.67	$ 1.25	$ 1.95	$ 2.03	$ 1.35	$ 0.68	$ 0.88	$ 1.89	$ 2.84
RIDER CCR	$ -	$ -	$ -	$ 2.95	$ 2.96	$ 2.38	$ 1.19	$ 3.13	$ 3.13	$ 3.13	$ 3.14
RIDER RGGI	$ -	$ -	$ -	$ 2.39	$ -	$ 4.64	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.92	$ 2.40	$ 3.55
RPS Program-Related Resources											
RIDER RPS [6]	$ -	$ -	$ -	$ 0.18	$ 1.81	$ 1.32	$ 4.69	$ 5.02	$ 4.81	$ 7.38	$ 9.16
RIDER CE [7]	$ -	$ -	$ -	$ 0.19	$ 1.67	$ 2.87	$ 4.10	$ 6.07	$ 6.28	$ 8.15	$ 9.29
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.38)	$ (1.15)	$ (1.22)	$ (1.43)	$ (1.90)	$ (2.13)	$ (2.30)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.16)	$ (1.40)	$ (2.49)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.03)	$ (0.03)	$ -	$ (0.96)	$ (0.77)	$ (0.61)	$ (1.12)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 1.26**	**$ 1.69**	**$ 2.89**	**$ 3.69**	**$ 2.46**	**$ 4.02**	**$ 3.38**
RIDER OSW [8]	$ -	$ -	$ -	$ -	$ 1.45	$ 4.74	$ 8.63	$ 9.07	$ 11.89	$ 12.51	$ 11.44
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.45)	$ (3.40)	$ (3.20)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.13)	$ (4.02)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.31)	$ (2.21)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.45**	**$ 4.74**	**$ 8.63**	**$ 9.07**	**$ 9.44**	**$ 5.67**	**$ 2.02**
NUCLEAR SMALL MODULAR REACTORS [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.07	$ 0.41	$ 1.43	$ 1.43
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 4.52**	**$ 7.75**	**$ 16.21**	**$ 17.84**	**$ 17.12**	**$ 18.51**	**$ 15.98**
TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.54**	**$ 122.72**	**$ 140.22**	**$ 134.16**	**$ 140.18**	**$ 151.13**	**$ 159.51**	**$ 167.38**	**$ 173.03**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

RESIDENTIAL Schedule 1 (1,000 kWh)	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]	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 33.42	$ 36.28	$ 39.06	$ 41.78	$ 44.44	$ 46.50	$ 48.21	$ 50.08	$ 51.89	$ 53.66	$ 55.41
FUEL - RIDER A	$ 31.07	$ 35.25	$ 37.60	$ 41.43	$ 43.40	$ 46.43	$ 47.04	$ 50.95	$ 54.29	$ 59.33	$ 64.43
FUEL SECURITIZATION	$ 2.73	$ 2.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1.94	$ 1.98	$ 2.02	$ 2.06	$ 2.10	$ 2.14	$ 2.19	$ 2.19	$ 2.19	$ 2.19	$ 2.19
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 5.62	$ 5.65	$ 5.41	$ 5.41	$ 5.66	$ 5.48	$ 5.52	$ 5.49	$ 5.72	$ 5.92	$ 5.60
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 1.02	$ 0.99	$ 0.98	$ 0.95	$ 0.92	$ 0.90	$ 0.87	$ 0.85	$ 0.83	$ 0.80	$ 0.78
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 6.27	$ 7.46	$ 7.99	$ 8.39	$ 8.38	$ 8.34	$ 8.15	$ 7.88	$ 7.58	$ 7.28	$ 6.98
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ 5.80	$ 6.00	$ 5.82	$ 5.66	$ 5.49	$ 5.25	$ 5.06	$ 4.84	$ 4.65	$ 4.49	$ 4.32
STRATEGIC UNDERGROUND PLAN	$ 4.92	$ 5.01	$ 4.69	$ 4.59	$ 4.49	$ 4.38	$ 4.28	$ 4.17	$ 4.07	$ 3.98	$ 3.88
RURAL BROADBAND	$ 0.59	$ 0.57	$ 0.56	$ 0.54	$ 0.52	$ 0.51	$ 0.49	$ 0.47	$ 0.45	$ 0.43	$ 0.42
A5 Environmental											
RIDER E [5]	$ 4.19	$ 4.60	$ 4.32	$ 4.00	$ 3.92	$ 3.75	$ 3.58	$ 3.41	$ 3.25	$ 3.08	$ 2.90
RIDER CCR	$ 4.22	$ 4.42	$ 4.45	$ 3.76	$ 5.09	$ 4.05	$ 4.03	$ 1.50	$ 0.30	$ 0.46	$ 0.19
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ 5.56	$ 8.06	$ 10.89	$ 14.11	$ 16.35	$ 17.02	$ 18.32	$ 19.26	$ 18.76	$ 18.26	$ 17.77
RPS Program-Related Resources											
RIDER RPS [6]	$ 10.44	$ 11.81	$ 13.34	$ 14.33	$ 15.35	$ 15.64	$ 16.00	$ 16.68	$ 18.24	$ 19.06	$ 20.38
RIDER CE [7]	$ 11.24	$ 13.18	$ 15.25	$ 17.39	$ 19.64	$ 22.16	$ 24.81	$ 27.85	$ 30.92	$ 33.49	$ 35.71
RIDER CE - FUEL BENEFIT	$ (2.82)	$ (3.29)	$ (3.80)	$ (4.22)	$ (4.78)	$ (5.34)	$ (5.89)	$ (6.80)	$ (7.74)	$ (8.74)	$ (9.75)
RIDER CE - REC PROXY VALUE	$ (2.98)	$ (3.84)	$ (4.70)	$ (5.26)	$ (5.62)	$ (5.83)	$ (5.93)	$ (5.90)	$ (6.20)	$ (6.43)	$ (6.60)
RIDER CE - CAPACITY OFFSET	$ (1.82)	$ (2.52)	$ (3.08)	$ (3.74)	$ (4.44)	$ (4.92)	$ (5.49)	$ (6.01)	$ (6.46)	$ (7.10)	$ (7.80)
TOTAL RIDER CE	**$ 3.62**	**$ 3.53**	**$ 3.67**	**$ 4.17**	**$ 4.81**	**$ 6.07**	**$ 7.50**	**$ 9.14**	**$ 10.52**	**$ 11.22**	**$ 11.55**
RIDER OSW [8]	$ 10.57	$ 10.36	$ 11.65	$ 17.93	$ 16.06	$ 20.28	$ 25.30	$ 31.46	$ 34.53	$ 33.65	$ 33.13
RIDER OSW - FUEL BENEFIT	$ (3.20)	$ (3.20)	$ (3.08)	$ (2.97)	$ (2.94)	$ (2.92)	$ (2.90)	$ (3.56)	$ (6.68)	$ (7.25)	$ (8.67)
RIDER OSW - REC PROXY VALUE	$ (4.03)	$ (4.01)	$ (4.01)	$ (3.74)	$ (3.47)	$ (3.18)	$ (2.90)	$ (2.62)	$ (2.78)	$ (4.83)	$ (4.68)
RIDER OSW - CAPACITY OFFSET	$ (2.28)	$ (2.32)	$ (2.43)	$ (2.43)	$ (2.17)	$ (1.77)	$ (1.63)	$ (1.71)	$ (2.85)	$ (3.73)	$ (4.24)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 1.06**	**$ 0.82**	**$ 2.14**	**$ 8.79**	**$ 7.47**	**$ 12.40**	**$ 17.87**	**$ 23.58**	**$ 22.22**	**$ 17.84**	**$ 15.54**
NUCLEAR SMALL MODULAR REACTORS [9]	$ 1.43	$ 1.38	$ 5.80	$ 8.84	$ 12.41	$ 15.99	$ 18.89	$ 21.22	$ 22.56	$ 23.14	$ 22.08
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 16.55**	**$ 17.55**	**$ 24.94**	**$ 36.13**	**$ 40.04**	**$ 50.10**	**$ 60.26**	**$ 70.63**	**$ 73.54**	**$ 71.26**	**$ 69.55**
TOTAL	**$ 184.64**	**$ 197.14**	**$ 209.44**	**$ 229.53**	**$ 241.53**	**$ 255.56**	**$ 268.71**	**$ 282.45**	**$ 288.24**	**$ 291.86**	**$ 295.14**
CAGR (2019 BASE)							5.0%				4.5%
CAGR (MAY 2020 BASE)							5.5%				4.9%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - REC RPS ONLY WITH 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 100.78	$ 113.32	$ 127.67	$ 142.15	$ 155.77
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 141.38	$ 179.48	$ 167.60	$ 177.34	$ 186.44
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 18.81	$ 16.68	$ 17.57	$ 16.68	$ 16.40
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 8.82	$ 6.36	$ 7.55	$ 7.33	$ 7.59	$ 7.79	$ 7.94
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 33.69	$ 22.82	$ 27.09	$ 25.63	$ 26.82
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.35	$ 2.77	$ 2.92	$ 4.28	$ 4.85
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 17.02	$ 18.67	$ 20.71	$ 24.50	$ 29.95
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 4.73	$ 1.40	$ 10.89	$ 7.70	$ 13.57	$ 16.57	$ 17.64	$ 19.63
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18	$ 9.86	$ 8.26	$ 14.42	$ 16.01	$ 13.87	$ 15.48	$ 16.73	$ 17.00
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12	$ 0.82	$ 0.97	$ 1.52	$ 2.01	$ 2.34	$ 2.30	$ 2.19	$ 2.12
A5 Environmental												
RIDER E [5]	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.25	$ 3.56	$ 2.93	$ 3.19	$ 3.78
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.13	$ 18.79	$ 18.76	$ 18.76	$ 18.82	$ 25.34
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 27.85	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.40	$ 11.46	$ 16.94	$ 26.56
RPS Program-Related Resources												
RIDER RPS [6]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 30.11	$ 28.85	$ 44.30	$ 54.94	$ 62.63
RIDER CE [7]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.44	$ 17.97	$ 27.75	$ 29.00	$ 38.44	$ 44.70	$ 55.53
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.56)	$ (11.41)	$ (12.76)	$ (13.81)	$ (16.93)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.94)	$ (8.39)	$ (14.93)	$ (17.88)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (3.43)	$ (2.72)	$ (5.02)	$ (8.14)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.73**	**$ 10.68**	**$ 14.90**	**$ 7.22**	**$ 14.57**	**$ 10.93**	**$ 12.58**
RIDER OSW [8]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 44.45	$ 58.31	$ 61.34	$ 56.11	$ 51.83
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14.71)	$ (20.39)	$ (19.19)	$ (19.19)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12.77)	$ (24.12)	$ (24.18)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.43)	$ (10.84)	$ (11.19)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 44.45**	**$ 43.60**	**$ 21.74**	**$ 1.96**	**$ (2.72)**
NUCLEAR SMALL MODULAR REACTORS [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.34	$ 1.97	$ 6.83	$ 6.83	$ 6.83
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.36**	**$ 74.18**	**$ 89.80**	**$ 81.64**	**$ 87.44**	**$ 74.66**	**$ 79.31**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 645.77**	**$ 646.46**	**$ 723.72**	**$ 763.80**	**$ 790.70**	**$ 813.14**	**$ 866.51**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.00	$ 2.00	$ 3.00	$ 4.00
TRANSMISSION - RIDER T	$ 169.08	$ 182.06	$ 194.74	$ 207.11	$ 216.70	$ 224.70	$ 233.41	$ 241.86	$ 250.07	$ 258.23
FUEL - RIDER A	$ 211.47	$ 225.58	$ 248.59	$ 260.42	$ 278.55	$ 282.22	$ 305.72	$ 325.71	$ 355.99	$ 386.58
FUEL SECURITIZATION	$ 15.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 8.10	$ 8.26	$ 8.43	$ 8.60	$ 8.76	$ 8.94	$ 8.94	$ 8.94	$ 8.94	$ 8.94
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 26.98	$ 25.85	$ 25.79	$ 27.03	$ 26.17	$ 26.34	$ 26.23	$ 27.29	$ 28.27	$ 26.73
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 4.72	$ 4.67	$ 4.53	$ 4.39	$ 4.27	$ 4.16	$ 4.07	$ 3.95	$ 3.84	$ 3.72
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 35.61	$ 38.12	$ 40.06	$ 40.02	$ 39.82	$ 38.90	$ 37.63	$ 36.20	$ 34.76	$ 33.32
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ 20.29	$ 19.69	$ 19.15	$ 18.59	$ 17.77	$ 17.12	$ 16.38	$ 15.75	$ 15.19	$ 14.63
STRATEGIC UNDERGROUND PLAN	$ 17.34	$ 16.23	$ 15.87	$ 15.51	$ 15.16	$ 14.79	$ 14.44	$ 14.09	$ 13.75	$ 13.43
RURAL BROADBAND	$ 2.06	$ 2.00	$ 1.93	$ 1.87	$ 1.81	$ 1.75	$ 1.68	$ 1.62	$ 1.55	$ 1.49
A5 Environmental										
RIDER E [5]	$ 3.67	$ 2.96	$ 2.21	$ 2.56	$ 2.45	$ 2.35	$ 2.26	$ 2.16	$ 2.06	$ 1.91
RIDER CCR	$ 26.51	$ 26.70	$ 22.58	$ 30.55	$ 24.32	$ 24.20	$ 8.99	$ 1.81	$ 2.73	$ 1.15
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
GAS CT	$ 38.46	$ 52.01	$ 67.35	$ 78.07	$ 81.27	$ 87.45	$ 91.95	$ 89.55	$ 87.18	$ 84.84
RPS Program-Related Resources										
RIDER RPS [6]	$ 70.86	$ 80.03	$ 86.00	$ 92.09	$ 93.82	$ 95.99	$ 100.10	$ 109.41	$ 114.34	$ 122.28
RIDER CE [7]	$ 66.37	$ 77.96	$ 89.94	$ 102.51	$ 116.35	$ 130.93	$ 147.40	$ 164.03	$ 178.61	$ 191.56
RIDER CE - FUEL BENEFIT	$ (19.73)	$ (22.81)	$ (25.33)	$ (28.66)	$ (32.06)	$ (35.32)	$ (40.79)	$ (46.42)	$ (52.46)	$ (58.50)
RIDER CE - REC PROXY VALUE	$ (23.03)	$ (28.22)	$ (31.56)	$ (33.72)	$ (34.96)	$ (35.56)	$ (35.39)	$ (37.22)	$ (38.55)	$ (39.61)
RIDER CE - CAPACITY OFFSET	$ (11.27)	$ (13.78)	$ (16.72)	$ (19.87)	$ (22.01)	$ (24.57)	$ (26.88)	$ (28.89)	$ (31.76)	$ (34.93)
TOTAL RIDER CE	**$ 12.34**	**$ 13.16**	**$ 16.34**	**$ 20.26**	**$ 27.31**	**$ 35.49**	**$ 44.34**	**$ 51.50**	**$ 55.84**	**$ 58.53**
RIDER OSW [8]	$ 50.81	$ 57.13	$ 87.89	$ 78.71	$ 99.40	$ 124.05	$ 154.25	$ 169.27	$ 164.99	$ 162.41
RIDER OSW - FUEL BENEFIT	$ (19.22)	$ (18.50)	$ (17.84)	$ (17.65)	$ (17.52)	$ (17.41)	$ (21.34)	$ (40.09)	$ (43.52)	$ (52.00)
RIDER OSW - REC PROXY VALUE	$ (24.07)	$ (24.04)	$ (22.42)	$ (20.82)	$ (19.08)	$ (17.40)	$ (15.71)	$ (16.67)	$ (28.97)	$ (28.06)
RIDER OSW - CAPACITY OFFSET	$ (11.39)	$ (11.89)	$ (11.93)	$ (10.65)	$ (8.68)	$ (7.99)	$ (8.38)	$ (13.97)	$ (18.27)	$ (20.78)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (3.88)**	**$ 2.69**	**$ 35.70**	**$ 29.60**	**$ 54.12**	**$ 81.26**	**$ 108.82**	**$ 98.54**	**$ 74.23**	**$ 61.57**
NUCLEAR SMALL MODULAR REACTORS [9]	$ 6.59	$ 27.68	$ 42.20	$ 59.24	$ 76.33	$ 90.16	$ 101.32	$ 107.72	$ 110.46	$ 105.41
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 85.92**	**$ 123.56**	**$ 180.23**	**$ 201.19**	**$ 251.58**	**$ 302.90**	**$ 354.58**	**$ 367.17**	**$ 354.88**	**$ 347.79**
TOTAL	**$ 930.50**	**$ 992.28**	**$ 1,096.05**	**$ 1,160.50**	**$ 1,233.22**	**$ 1,300.41**	**$ 1,371.86**	**$ 1,402.69**	**$ 1,426.79**	**$ 1,451.35**
CAGR (2019 BASE)						5.2%				4.7%
CAGR (MAY 2020 BASE)						5.9%				5.2%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
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LARGE GENERAL BILL PROJECTION - REC RPS ONLY WITH 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	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (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	$ 67,880.00	$ 76,330.00	$ 86,000.00	$ 95,750.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 141,384.00	$ 179,484.00	$ 167,604.00	$ 177,336.00
FUEL SECURITIZATION	$ 139,524.00	$ 104,142.00	$ -	$ -	$ -	$ -	$ 20,226.00	$ 18,809.25	$ 16,684.83	$ 17,569.35	$ 16,679.55
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 330.00	$ 474.00	$ 546.00	$ 624.00	$ 660.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 17,920.00	$ 12,130.00	$ 14,390.00	$ 13,630.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,250.00	$ 1,470.00	$ 1,550.00	$ 2,270.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 9,040.00	$ 9,930.00	$ 11,010.00	$ 13,020.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1,160.00	$ 360.00	$ 2,670.00	$ 1,890.00	$ 3,330.00	$ 4,070.00	$ 4,330.00
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00	$ 130.00	$ 150.00	$ 230.00	$ 300.00	$ 350.00	$ 340.00	$ 330.00
A5 Environmental											
RIDER E [5]	$ 5,560.00	$ 5,560.00	$ 4,300.00	$ 3,140.00	$ 4,860.00	$ 4,440.00	$ 3,260.00	$ 1,730.00	$ 1,890.00	$ 1,560.00	$ 1,690.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,128.00	$ 18,786.00	$ 18,762.00	$ 18,762.00	$ 18,816.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 27,852.00	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,340.00	$ 6,090.00	$ 9,010.00
RPS Program-Related Resources											
RIDER RPS [6]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 30,114.00	$ 28,848.00	$ 44,304.00	$ 54,936.00
RIDER CE [7]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 15,162.00	$ 16,420.00	$ 23,280.00	$ 28,700.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (8,562.00)	$ (11,406.00)	$ (12,762.00)	$ (13,812.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,936.00)	$ (8,388.00)	$ (14,934.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (1,750.00)	$ (1,360.00)	$ (2,540.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,420.00**	**$ (3,672.00)**	**$ 770.00**	**$ (2,586.00)**
RIDER OSW [8]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 23,730.00	$ 31,130.00	$ 32,750.00	$ 29,960.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14,712.00)	$ (20,394.00)	$ (19,188.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,774.00)	$ (24,120.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,430.00)	$ (5,790.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 23,730.00**	**$ 16,418.00**	**$ (3,848.00)**	**$ (19,138.00)**
NUCLEAR SMALL MODULAR REACTORS [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180.00	$ 1,050.00	$ 3,630.00	$ 3,630.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 58,444.00**	**$ 42,644.00**	**$ 44,856.00**	**$ 36,842.00**
TOTAL	**$ 490,384.69**	**$ 417,020.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 434,195.69**	**$ 412,701.63**	**$ 461,469.96**	**$ 489,453.54**	**$ 497,988.06**	**$ 513,926.26**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

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]	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.00	$ 2.00	$ 3.00	$ 4.00
TRANSMISSION - RIDER T	$ 104,930.00	$ 113,890.00	$ 122,630.00	$ 131,170.00	$ 139,510.00	$ 145,970.00	$ 151,360.00	$ 157,220.00	$ 162,920.00	$ 168,450.00	$ 173,940.00
FUEL - RIDER A	$ 186,444.00	$ 211,470.00	$ 225,582.00	$ 248,592.00	$ 260,424.00	$ 278,550.00	$ 282,216.00	$ 305,724.00	$ 325,710.00	$ 355,986.00	$ 386,580.00
FUEL SECURITIZATION	$ 16,399.86	$ 15,700.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 678.00	$ 690.00	$ 702.00	$ 720.00	$ 732.00	$ 744.00	$ 762.00	$ 762.00	$ 762.00	$ 762.00	$ 762.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 14,260.00	$ 14,340.00	$ 13,730.00	$ 13,720.00	$ 14,360.00	$ 13,900.00	$ 14,000.00	$ 13,930.00	$ 14,490.00	$ 15,030.00	$ 14,200.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 2,580.00	$ 2,510.00	$ 2,480.00	$ 2,410.00	$ 2,330.00	$ 2,270.00	$ 2,210.00	$ 2,160.00	$ 2,100.00	$ 2,040.00	$ 1,980.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 15,910.00	$ 18,930.00	$ 20,270.00	$ 21,290.00	$ 21,270.00	$ 21,160.00	$ 20,680.00	$ 20,000.00	$ 19,240.00	$ 18,480.00	$ 17,710.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ 4,820.00	$ 4,980.00	$ 4,830.00	$ 4,700.00	$ 4,560.00	$ 4,360.00	$ 4,200.00	$ 4,020.00	$ 3,870.00	$ 3,730.00	$ 3,590.00
RURAL BROADBAND	$ 320.00	$ 310.00	$ 300.00	$ 290.00	$ 280.00	$ 270.00	$ 260.00	$ 250.00	$ 240.00	$ 230.00	$ 220.00
A5 Environmental											
RIDER E [5]	$ 2,010.00	$ 1,950.00	$ 1,580.00	$ 1,180.00	$ 1,360.00	$ 1,310.00	$ 1,250.00	$ 1,210.00	$ 1,160.00	$ 1,100.00	$ 1,020.00
RIDER CCR	$ 25,344.00	$ 26,514.00	$ 26,700.00	$ 22,584.00	$ 30,546.00	$ 24,318.00	$ 24,204.00	$ 8,994.00	$ 1,812.00	$ 2,730.00	$ 1,146.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ 14,120.00	$ 20,440.00	$ 27,640.00	$ 35,800.00	$ 41,490.00	$ 43,190.00	$ 46,480.00	$ 48,870.00	$ 47,590.00	$ 46,330.00	$ 45,100.00
RPS Program-Related Resources											
RIDER RPS [6]	$ 62,628.00	$ 70,860.00	$ 80,034.00	$ 85,998.00	$ 92,094.00	$ 93,822.00	$ 95,994.00	$ 100,104.00	$ 109,410.00	$ 114,342.00	$ 122,280.00
RIDER CE [7]	$ 38,276.00	$ 48,038.00	$ 58,348.00	$ 69,140.00	$ 80,294.00	$ 92,360.00	$ 105,028.00	$ 118,942.00	$ 132,982.00	$ 146,298.00	$ 158,820.00
RIDER CE - FUEL BENEFIT	$ (16,926.00)	$ (19,728.00)	$ (22,806.00)	$ (25,326.00)	$ (28,662.00)	$ (32,058.00)	$ (35,316.00)	$ (40,788.00)	$ (46,422.00)	$ (52,458.00)	$ (58,500.00)
RIDER CE - REC PROXY VALUE	$ (17,880.00)	$ (23,028.00)	$ (28,218.00)	$ (31,560.00)	$ (33,720.00)	$ (34,962.00)	$ (35,556.00)	$ (35,388.00)	$ (37,224.00)	$ (38,550.00)	$ (39,606.00)
RIDER CE - CAPACITY OFFSET	$ (4,140.00)	$ (5,710.00)	$ (6,980.00)	$ (8,470.00)	$ (10,090.00)	$ (11,170.00)	$ (12,470.00)	$ (13,630.00)	$ (14,670.00)	$ (16,130.00)	$ (17,720.00)
TOTAL RIDER CE	**$ (670.00)**	**$ (428.00)**	**$ 344.00**	**$ 3,784.00**	**$ 7,822.00**	**$ 14,170.00**	**$ 21,686.00**	**$ 29,136.00**	**$ 34,666.00**	**$ 39,160.00**	**$ 42,994.00**
RIDER OSW [8]	$ 27,680.00	$ 27,130.00	$ 30,500.00	$ 46,930.00	$ 42,020.00	$ 53,080.00	$ 66,240.00	$ 82,360.00	$ 90,380.00	$ 88,100.00	$ 86,710.00
RIDER OSW - FUEL BENEFIT	$ (19,188.00)	$ (19,218.00)	$ (18,504.00)	$ (17,844.00)	$ (17,646.00)	$ (17,520.00)	$ (17,406.00)	$ (21,336.00)	$ (40,092.00)	$ (43,518.00)	$ (51,996.00)
RIDER OSW - REC PROXY VALUE	$ (24,180.00)	$ (24,072.00)	$ (24,042.00)	$ (22,416.00)	$ (20,820.00)	$ (19,080.00)	$ (17,400.00)	$ (15,714.00)	$ (16,668.00)	$ (28,968.00)	$ (28,062.00)
RIDER OSW - CAPACITY OFFSET	$ (5,980.00)	$ (6,080.00)	$ (6,350.00)	$ (6,370.00)	$ (5,690.00)	$ (4,640.00)	$ (4,260.00)	$ (4,470.00)	$ (7,460.00)	$ (9,760.00)	$ (11,090.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (21,668.00)**	**$ (22,240.00)**	**$ (18,396.00)**	**$ 300.00**	**$ (2,136.00)**	**$ 11,840.00**	**$ 27,174.00**	**$ 40,840.00**	**$ 26,160.00**	**$ 5,854.00**	**$ (4,438.00)**
NUCLEAR SMALL MODULAR REACTORS [9]	$ 3,630.00	$ 3,500.00	$ 14,710.00	$ 22,430.00	$ 31,480.00	$ 40,570.00	$ 47,920.00	$ 53,850.00	$ 57,260.00	$ 58,710.00	$ 56,030.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 43,920.00**	**$ 51,692.00**	**$ 76,692.00**	**$ 112,512.00**	**$ 129,260.00**	**$ 160,402.00**	**$ 192,774.00**	**$ 223,930.00**	**$ 227,496.00**	**$ 218,066.00**	**$ 216,866.00**
TOTAL	**$ 555,298.57**	**$ 606,979.25**	**$ 646,698.71**	**$ 718,530.71**	**$ 769,684.71**	**$ 820,006.71**	**$ 863,958.71**	**$ 910,633.71**	**$ 930,954.71**	**$ 956,499.71**	**$ 986,680.71**
CAGR (2019 BASE)							3.6%				3.6%
CAGR (MAY 2020 BASE)							4.8%				4.5%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Company owned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - VCEA WITH EPA, 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 60.93	$ 60.93	$ 60.71	$ 60.72	$ 60.72	$ 60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (0.47)	$ (0.43)	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	$ 12.91	$ 15.58	$ 19.40	$ 21.62	$ 24.31	$ 27.39
FUEL - RIDER A	$ 23.25	$ 17.36	$ 17.02	$ 20.45	$ 35.38	$ 28.59	$ 20.74	$ 23.56	$ 30.11	$ 28.97
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.37	$ 3.13	$ 2.78	$ 2.93
DSM	$ 1.13	$ 1.13	$ 1.47	$ 1.31	$ 1.60	$ 1.84	$ 1.55	$ 1.85	$ 1.79	$ 1.85
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.03	$ 0.03	$ 0.73	$ -	$ -	$ -	$ -
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	$ 14.51	$ 6.67	$ 6.58	$ 7.06	$ 4.78	$ 5.67
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.49	$ 0.58	$ 0.61
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 2.07	$ 0.93	$ 1.29	$ 3.57	$ 3.91	$ 4.34
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1.16	$ 0.30	$ 3.22	$ 2.27	$ 4.01	$ 4.90
STRATEGIC UNDERGROUND PLAN	$ 1.84	$ 1.40	$ 1.40	$ 2.14	$ 2.49	$ 1.99	$ 4.17	$ 4.63	$ 4.01	$ 4.48
RURAL BROADBAND	$ -	$ -	$ -	$ 0.03	$ 0.19	$ 0.23	$ 0.42	$ 0.56	$ 0.65	$ 0.64
A5 Environmental										
RIDER E [5]	$ 1.99	$ 1.99	$ 1.67	$ 1.25	$ 1.95	$ 2.03	$ 1.35	$ 0.68	$ 0.88	$ 1.89
RIDER CCR	$ -	$ -	$ -	$ 2.95	$ 2.96	$ 2.38	$ 1.19	$ 3.13	$ 3.13	$ 3.13
RIDER RGGI	$ -	$ -	$ -	$ 2.39	$ -	$ 4.64	$ -	$ -	$ -	$ -
Additional Resources										
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.14	$ 2.18
RPS Program-Related Resources										
RIDER RPS [6]	$ -	$ -	$ -	$ 0.18	$ 1.81	$ 1.32	$ 4.69	$ 5.02	$ 4.81	$ 7.38
RIDER CE [7]	$ -	$ -	$ -	$ 0.19	$ 1.67	$ 2.87	$ 4.10	$ 6.07	$ 9.11	$ 11.75
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.38)	$ (1.15)	$ (1.22)	$ (1.43)	$ (1.91)	$ (2.19)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.16)	$ (1.41)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.03)	$ (0.03)	$ -	$ (0.96)	$ (0.77)	$ (0.62)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 1.26**	**$ 1.69**	**$ 2.89**	**$ 3.69**	**$ 5.27**	**$ 7.53**
RIDER OSW [8]	$ -	$ -	$ -	$ -	$ 1.45	$ 4.74	$ 8.63	$ 9.07	$ 11.89	$ 12.51
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.45)	$ (3.40)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.13)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.31)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.45**	**$ 4.74**	**$ 8.63**	**$ 9.07**	**$ 9.44**	**$ 5.67**
NUCLEAR SMALL MODULAR REACTORS [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.07	$ 0.41	$ 1.43
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 4.52**	**$ 7.75**	**$ 16.21**	**$ 17.84**	**$ 19.93**	**$ 22.02**
TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.54**	**$ 122.72**	**$ 140.22**	**$ 134.16**	**$ 140.18**	**$ 151.13**	**$ 162.73**	**$ 171.71**
CAGR (2019 BASE)										
CAGR (MAY 2020 BASE)										

RESIDENTIAL Schedule 1 (1,000 kWh)	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	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039
DISTRIBUTION & GENERATION (BASE) [1]	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 30.50	$ 33.42	$ 36.28	$ 39.06	$ 41.78	$ 44.44	$ 46.50	$ 48.21	$ 50.08	$ 51.89	$ 53.66	$ 55.41
FUEL - RIDER A	$ 30.65	$ 31.95	$ 35.96	$ 38.38	$ 41.04	$ 43.06	$ 45.51	$ 47.26	$ 50.77	$ 55.28	$ 61.20	$ 65.60
FUEL SECURITIZATION	$ 2.78	$ 2.73	$ 2.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 1.91	$ 1.94	$ 1.98	$ 2.02	$ 2.06	$ 2.10	$ 2.14	$ 2.19	$ 2.19	$ 2.19	$ 2.19	$ 2.19
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 5.37	$ 5.62	$ 5.65	$ 5.41	$ 5.41	$ 5.66	$ 5.48	$ 5.52	$ 5.49	$ 5.72	$ 5.92	$ 5.60
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 0.90	$ 1.02	$ 0.99	$ 0.98	$ 0.95	$ 0.92	$ 0.90	$ 0.87	$ 0.85	$ 0.83	$ 0.80	$ 0.78
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 5.13	$ 6.27	$ 7.46	$ 7.99	$ 8.39	$ 8.38	$ 8.34	$ 8.15	$ 7.88	$ 7.58	$ 7.28	$ 6.98
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ 5.21	$ 5.80	$ 6.00	$ 5.82	$ 5.66	$ 5.49	$ 5.25	$ 5.06	$ 4.84	$ 4.65	$ 4.49	$ 4.32
STRATEGIC UNDERGROUND PLAN	$ 4.84	$ 4.92	$ 5.01	$ 4.69	$ 4.59	$ 4.49	$ 4.38	$ 4.28	$ 4.17	$ 4.07	$ 3.98	$ 3.88
RURAL BROADBAND	$ 0.61	$ 0.59	$ 0.57	$ 0.56	$ 0.54	$ 0.52	$ 0.51	$ 0.49	$ 0.47	$ 0.45	$ 0.43	$ 0.42
A5 Environmental												
RIDER E [5]	$ 2.84	$ 4.19	$ 4.60	$ 4.32	$ 4.00	$ 3.92	$ 3.75	$ 3.58	$ 3.41	$ 3.25	$ 3.08	$ 2.90
RIDER CCR	$ 3.14	$ 4.22	$ 4.42	$ 4.45	$ 3.76	$ 5.09	$ 4.05	$ 4.03	$ 1.50	$ 0.30	$ 0.46	$ 0.19
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ 4.25	$ 6.32	$ 8.48	$ 10.75	$ 14.34	$ 16.73	$ 18.10	$ 18.21	$ 19.10	$ 18.67	$ 18.21	$ 17.73
RPS Program-Related Resources												
RIDER RPS [6]	$ 9.16	$ 10.44	$ 11.81	$ 13.33	$ 14.33	$ 15.34	$ 15.63	$ 15.90	$ 16.32	$ 17.79	$ 19.09	$ 20.40
RIDER CE [7]	$ 14.45	$ 18.03	$ 21.55	$ 25.32	$ 29.15	$ 32.87	$ 36.83	$ 40.71	$ 44.73	$ 48.50	$ 50.99	$ 52.84
RIDER CE - FUEL BENEFIT	$ (2.38)	$ (3.00)	$ (3.50)	$ (4.05)	$ (4.50)	$ (5.11)	$ (5.74)	$ (6.34)	$ (7.33)	$ (8.36)	$ (9.46)	$ (10.57)
RIDER CE - REC PROXY VALUE	$ (2.57)	$ (3.07)	$ (4.09)	$ (5.01)	$ (5.60)	$ (6.00)	$ (6.24)	$ (6.36)	$ (6.35)	$ (6.69)	$ (6.94)	$ (7.15)
RIDER CE - CAPACITY OFFSET	$ (1.07)	$ (1.74)	$ (2.45)	$ (3.02)	$ (3.69)	$ (4.40)	$ (4.89)	$ (5.47)	$ (5.98)	$ (6.44)	$ (7.10)	$ (7.82)
TOTAL RIDER CE	**$ 8.43**	**$ 10.22**	**$ 11.52**	**$ 13.25**	**$ 15.36**	**$ 17.36**	**$ 19.97**	**$ 22.54**	**$ 25.07**	**$ 27.02**	**$ 27.49**	**$ 27.32**
RIDER OSW [8]	$ 11.44	$ 10.78	$ 10.96	$ 11.59	$ 15.38	$ 16.73	$ 19.11	$ 21.24	$ 28.50	$ 33.16	$ 34.04	$ 34.46
RIDER OSW - FUEL BENEFIT	$ (3.20)	$ (3.20)	$ (3.20)	$ (3.08)	$ (2.97)	$ (3.05)	$ (3.82)	$ (3.80)	$ (4.10)	$ (4.36)	$ (5.16)	$ (8.67)
RIDER OSW - REC PROXY VALUE	$ (4.02)	$ (4.03)	$ (4.01)	$ (4.01)	$ (3.74)	$ (3.47)	$ (3.28)	$ (3.80)	$ (3.43)	$ (3.30)	$ (3.15)	$ (3.24)
RIDER OSW - CAPACITY OFFSET	$ (2.21)	$ (2.28)	$ (2.32)	$ (2.43)	$ (2.43)	$ (2.17)	$ (2.06)	$ (2.13)	$ (2.24)	$ (2.33)	$ (2.43)	$ (3.70)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 2.02**	**$ 1.27**	**$ 1.42**	**$ 2.07**	**$ 6.24**	**$ 8.04**	**$ 9.95**	**$ 11.51**	**$ 18.73**	**$ 23.16**	**$ 23.30**	**$ 18.86**
NUCLEAR SMALL MODULAR REACTORS [9]	$ 1.43	$ 1.43	$ 1.38	$ 5.80	$ 8.84	$ 12.41	$ 15.99	$ 18.89	$ 21.22	$ 22.56	$ 23.14	$ 22.08
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 21.03**	**$ 23.35**	**$ 26.12**	**$ 34.45**	**$ 44.77**	**$ 53.15**	**$ 61.53**	**$ 68.84**	**$ 81.35**	**$ 90.53**	**$ 93.02**	**$ 88.66**
TOTAL	**$ 179.87**	**$ 193.07**	**$ 206.85**	**$ 219.58**	**$ 238.00**	**$ 254.67**	**$ 267.15**	**$ 277.41**	**$ 292.82**	**$ 306.14**	**$ 315.43**	**$ 315.36**
CAGR (2019 BASE)								5.2%				4.8%
CAGR (MAY 2020 BASE)								5.7%				5.2%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Companyowned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - VCEA WITH 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 100.78	$ 113.32	$ 127.67	$ 142.15	$ 155.77
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 141.38	$ 180.67	$ 173.84	$ 183.88	$ 191.70
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 18.81	$ 16.68	$ 17.57	$ 16.68	$ 16.40
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 8.82	$ 6.36	$ 7.55	$ 7.33	$ 7.59	$ 7.79	$ 7.94
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 33.69	$ 22.82	$ 27.09	$ 25.63	$ 26.82
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.35	$ 2.77	$ 2.92	$ 4.28	$ 4.85
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 17.02	$ 18.67	$ 20.71	$ 24.50	$ 29.95
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 4.73	$ 1.40	$ 10.89	$ 7.70	$ 13.57	$ 16.57	$ 17.64	$ 19.63
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18	$ 9.86	$ 8.26	$ 14.42	$ 16.01	$ 13.87	$ 15.48	$ 16.73	$ 17.00
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12	$ 0.82	$ 0.97	$ 1.52	$ 2.01	$ 2.34	$ 2.30	$ 2.19	$ 2.12
A5 Environmental												
RIDER E [5]	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.25	$ 4.21	$ 9.01	$ 13.58	$ 20.01
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.13	$ 18.79	$ 18.76	$ 18.76	$ 18.82	$ 25.34
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 27.85	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.44	$ 10.39	$ 20.29	$ 30.16
RPS Program-Related Resources												
RIDER RPS [6]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 30.11	$ 28.85	$ 44.29	$ 54.93	$ 62.62
RIDER CE [7]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.44	$ 17.97	$ 27.75	$ 41.62	$ 54.55	$ 67.77	$ 85.02
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.56)	$ (11.46)	$ (13.16)	$ (14.25)	$ (18.01)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.94)	$ (8.43)	$ (15.40)	$ (18.44)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (3.43)	$ (2.75)	$ (4.81)	$ (7.79)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.73**	**$ 10.68**	**$ 14.90**	**$ 19.79**	**$ 30.20**	**$ 33.31**	**$ 40.78**
RIDER OSW [8]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 44.45	$ 58.31	$ 61.34	$ 56.11	$ 52.86
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14.71)	$ (20.39)	$ (19.19)	$ (19.19)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12.77)	$ (24.12)	$ (24.18)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.43)	$ (10.84)	$ (11.19)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 44.45**	**$ 43.60**	**$ 21.74**	**$ 1.96**	**$ (1.70)**
NUCLEAR SMALL MODULAR REACTORS [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.34	$ 1.97	$ 6.83	$ 6.83	$ 6.83
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.36**	**$ 74.18**	**$ 89.80**	**$ 94.21**	**$ 103.06**	**$ 97.03**	**$ 108.52**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 645.77**	**$ 646.46**	**$ 723.72**	**$ 779.24**	**$ 817.56**	**$ 855.78**	**$ 920.81**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 169.08	$ 182.06	$ 194.74	$ 207.11	$ 216.70	$ 224.70	$ 233.41	$ 241.86	$ 250.07	$ 258.23
FUEL - RIDER A	$ 215.77	$ 230.26	$ 246.25	$ 258.36	$ 273.04	$ 283.54	$ 304.62	$ 331.66	$ 367.19	$ 393.57
FUEL SECURITIZATION	$ 15.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 8.10	$ 8.26	$ 8.43	$ 8.60	$ 8.76	$ 8.94	$ 8.94	$ 8.94	$ 8.94	$ 8.94
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 26.98	$ 25.85	$ 25.79	$ 27.03	$ 26.17	$ 26.34	$ 26.23	$ 27.29	$ 28.27	$ 26.73
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 4.72	$ 4.67	$ 4.53	$ 4.39	$ 4.27	$ 4.16	$ 4.07	$ 3.95	$ 3.84	$ 3.72
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 35.61	$ 38.12	$ 40.06	$ 40.02	$ 39.82	$ 38.90	$ 37.63	$ 36.20	$ 34.76	$ 33.32
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ 20.29	$ 19.69	$ 19.15	$ 18.59	$ 17.77	$ 17.12	$ 16.38	$ 15.75	$ 15.19	$ 14.63
STRATEGIC UNDERGROUND PLAN	$ 17.34	$ 16.23	$ 15.87	$ 15.51	$ 15.16	$ 14.79	$ 14.44	$ 14.09	$ 13.75	$ 13.43
RURAL BROADBAND	$ 2.06	$ 2.00	$ 1.93	$ 1.87	$ 1.81	$ 1.75	$ 1.68	$ 1.62	$ 1.55	$ 1.49
A5 Environmental										
RIDER E [5]	$ 21.94	$ 20.62	$ 19.12	$ 18.73	$ 17.90	$ 17.09	$ 16.30	$ 15.50	$ 14.71	$ 13.86
RIDER CCR	$ 26.51	$ 26.70	$ 22.58	$ 30.55	$ 24.32	$ 24.20	$ 8.99	$ 1.81	$ 2.73	$ 1.15
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
GAS CT	$ 40.49	$ 51.29	$ 68.44	$ 79.85	$ 86.42	$ 86.95	$ 91.16	$ 89.15	$ 86.94	$ 84.63
RPS Program-Related Resources										
RIDER RPS [6]	$ 70.83	$ 79.99	$ 85.96	$ 92.04	$ 93.76	$ 95.41	$ 97.94	$ 106.76	$ 114.52	$ 122.42
RIDER CE [7]	$ 102.00	$ 120.17	$ 138.70	$ 156.77	$ 175.94	$ 194.84	$ 214.44	$ 232.94	$ 245.86	$ 255.82
RIDER CE - FUEL BENEFIT	$ (20.99)	$ (24.28)	$ (27.02)	$ (30.68)	$ (34.42)	$ (38.01)	$ (43.97)	$ (50.15)	$ (56.78)	$ (63.40)
RIDER CE - REC PROXY VALUE	$ (24.52)	$ (30.04)	$ (33.61)	$ (35.99)	$ (37.43)	$ (38.17)	$ (38.08)	$ (40.13)	$ (41.65)	$ (42.88)
RIDER CE - CAPACITY OFFSET	$ (10.96)	$ (13.49)	$ (16.48)	$ (19.70)	$ (21.87)	$ (24.47)	$ (26.75)	$ (28.79)	$ (31.73)	$ (34.98)
TOTAL RIDER CE	**$ 45.53**	**$ 52.36**	**$ 61.59**	**$ 70.40**	**$ 82.22**	**$ 94.19**	**$ 105.63**	**$ 113.87**	**$ 115.69**	**$ 114.57**
RIDER OSW [8]	$ 53.72	$ 56.82	$ 75.40	$ 82.04	$ 93.70	$ 104.15	$ 139.70	$ 162.57	$ 166.90	$ 168.92
RIDER OSW - FUEL BENEFIT	$ (19.22)	$ (18.50)	$ (17.84)	$ (18.32)	$ (22.94)	$ (22.79)	$ (24.58)	$ (26.18)	$ (30.93)	$ (52.00)
RIDER OSW - REC PROXY VALUE	$ (24.07)	$ (24.04)	$ (22.42)	$ (20.82)	$ (19.67)	$ (22.78)	$ (20.57)	$ (19.82)	$ (18.92)	$ (19.44)
RIDER OSW - CAPACITY OFFSET	$ (11.39)	$ (11.89)	$ (11.93)	$ (10.65)	$ (10.09)	$ (10.46)	$ (10.97)	$ (11.44)	$ (11.93)	$ (18.11)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (0.96)**	**$ 2.38**	**$ 23.21**	**$ 32.24**	**$ 41.00**	**$ 48.12**	**$ 83.57**	**$ 105.13**	**$ 105.11**	**$ 79.37**
NUCLEAR SMALL MODULAR REACTORS [9]	$ 6.59	$ 27.68	$ 42.20	$ 59.24	$ 76.33	$ 90.16	$ 101.32	$ 107.72	$ 110.46	$ 105.41
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 122.00**	**$ 162.41**	**$ 212.96**	**$ 253.93**	**$ 293.30**	**$ 327.88**	**$ 388.47**	**$ 433.48**	**$ 445.79**	**$ 421.78**
TOTAL	**$ 991.18**	**$ 1,052.74**	**$ 1,144.42**	**$ 1,229.13**	**$ 1,290.03**	**$ 1,340.94**	**$ 1,416.90**	**$ 1,485.90**	**$ 1,538.32**	**$ 1,540.07**
CAGR (2019 BASE)						5.4%				5.1%
CAGR (MAY 2020 BASE)						6.1%				5.5%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Companyowned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - VCEA WITH 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	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (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	$ 67,880.00	$ 76,330.00	$ 86,000.00	$ 95,750.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 141,384.00	$ 180,672.00	$ 173,844.00	$ 183,876.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,226.00	$ 18,809.25	$ 16,684.83	$ 17,569.35	$ 16,679.55
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 330.00	$ 474.00	$ 546.00	$ 624.00	$ 660.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 17,920.00	$ 12,130.00	$ 14,390.00	$ 13,630.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,250.00	$ 1,470.00	$ 1,550.00	$ 2,270.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 9,040.00	$ 9,930.00	$ 11,010.00	$ 13,020.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1,160.00	$ 360.00	$ 2,670.00	$ 1,890.00	$ 3,330.00	$ 4,070.00	$ 4,330.00
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00	$ 130.00	$ 150.00	$ 230.00	$ 300.00	$ 350.00	$ 340.00	$ 330.00
A5 Environmental											
RIDER E [5]	$ 5,560.00	$ 5,560.00	$ 4,300.00	$ 3,140.00	$ 4,860.00	$ 4,440.00	$ 3,260.00	$ 1,730.00	$ 2,230.00	$ 4,790.00	$ 7,210.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,128.00	$ 18,786.00	$ 18,762.00	$ 18,762.00	$ 18,816.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 27,852.00	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,890.00	$ 5,520.00	$ 10,790.00
RPS Program-Related Resources											
RIDER RPS [6]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 30,114.00	$ 28,848.00	$ 44,292.00	$ 54,930.00
RIDER CE [7]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 15,162.00	$ 22,844.00	$ 31,494.00	$ 40,410.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (8,562.00)	$ (11,460.00)	$ (13,164.00)	$ (14,250.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,936.00)	$ (8,430.00)	$ (15,402.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (1,750.00)	$ (1,370.00)	$ (2,430.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,420.00**	**$ 2,698.00**	**$ 8,530.00**	**$ 8,328.00**
RIDER OSW [8]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 23,730.00	$ 31,130.00	$ 32,750.00	$ 29,960.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14,712.00)	$ (20,394.00)	$ (19,188.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,774.00)	$ (24,120.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,430.00)	$ (5,790.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 23,730.00**	**$ 16,418.00**	**$ (3,848.00)**	**$ (19,138.00)**
NUCLEAR SMALL MODULAR REACTORS [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180.00	$ 1,050.00	$ 3,630.00	$ 3,630.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 58,444.00**	**$ 49,014.00**	**$ 52,604.00**	**$ 47,750.00**
TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 434,195.69**	**$ 412,701.63**	**$ 461,469.96**	**$ 497,901.54**	**$ 514,636.06**	**$ 538,674.26**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

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]	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 104,930.00	$ 113,890.00	$ 122,630.00	$ 131,170.00	$ 139,510.00	$ 145,970.00	$ 151,360.00	$ 157,220.00	$ 162,920.00	$ 168,450.00	$ 173,940.00
FUEL - RIDER A	$ 191,700.00	$ 215,772.00	$ 230,256.00	$ 246,246.00	$ 258,360.00	$ 273,036.00	$ 283,536.00	$ 304,620.00	$ 331,662.00	$ 367,194.00	$ 393,570.00
FUEL SECURITIZATION	$ 16,399.86	$ 15,700.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 678.00	$ 690.00	$ 702.00	$ 720.00	$ 732.00	$ 744.00	$ 762.00	$ 762.00	$ 762.00	$ 762.00	$ 762.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 14,260.00	$ 14,340.00	$ 13,730.00	$ 13,720.00	$ 14,360.00	$ 13,900.00	$ 14,000.00	$ 13,930.00	$ 14,490.00	$ 15,030.00	$ 14,200.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 2,580.00	$ 2,510.00	$ 2,480.00	$ 2,410.00	$ 2,330.00	$ 2,270.00	$ 2,210.00	$ 2,160.00	$ 2,100.00	$ 2,040.00	$ 1,980.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 15,910.00	$ 18,930.00	$ 20,270.00	$ 21,290.00	$ 21,270.00	$ 21,160.00	$ 20,680.00	$ 20,000.00	$ 19,240.00	$ 18,480.00	$ 17,710.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ 4,820.00	$ 4,980.00	$ 4,830.00	$ 4,700.00	$ 4,560.00	$ 4,360.00	$ 4,200.00	$ 4,020.00	$ 3,870.00	$ 3,730.00	$ 3,590.00
RURAL BROADBAND	$ 320.00	$ 310.00	$ 300.00	$ 290.00	$ 280.00	$ 270.00	$ 260.00	$ 250.00	$ 240.00	$ 230.00	$ 220.00
A5 Environmental											
RIDER E [5]	$ 10,640.00	$ 11,660.00	$ 10,960.00	$ 10,170.00	$ 9,960.00	$ 9,520.00	$ 9,080.00	$ 8,670.00	$ 8,250.00	$ 7,820.00	$ 7,370.00
RIDER CCR	$ 25,344.00	$ 26,514.00	$ 26,700.00	$ 22,584.00	$ 30,546.00	$ 24,318.00	$ 24,204.00	$ 8,994.00	$ 1,812.00	$ 2,730.00	$ 1,146.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ 16,030.00	$ 21,520.00	$ 27,260.00	$ 36,380.00	$ 42,440.00	$ 45,930.00	$ 46,210.00	$ 48,460.00	$ 47,380.00	$ 46,220.00	$ 44,980.00
RPS Program-Related Resources											
RIDER RPS [6]	$ 62,616.00	$ 70,830.00	$ 79,992.00	$ 85,956.00	$ 92,040.00	$ 93,756.00	$ 95,406.00	$ 97,944.00	$ 106,758.00	$ 114,522.00	$ 122,424.00
RIDER CE [7]	$ 51,490.00	$ 62,530.00	$ 74,266.00	$ 86,360.00	$ 98,216.00	$ 110,830.00	$ 123,404.00	$ 136,486.00	$ 149,018.00	$ 158,908.00	$ 167,272.00
RIDER CE - FUEL BENEFIT	$ (18,012.00)	$ (20,994.00)	$ (24,282.00)	$ (27,024.00)	$ (30,678.00)	$ (34,416.00)	$ (38,010.00)	$ (43,974.00)	$ (50,148.00)	$ (56,784.00)	$ (63,396.00)
RIDER CE - REC PROXY VALUE	$ (18,438.00)	$ (24,516.00)	$ (30,036.00)	$ (33,606.00)	$ (35,988.00)	$ (37,428.00)	$ (38,172.00)	$ (38,082.00)	$ (40,134.00)	$ (41,646.00)	$ (42,876.00)
RIDER CE - CAPACITY OFFSET	$ (3,960.00)	$ (5,550.00)	$ (6,830.00)	$ (8,340.00)	$ (10,000.00)	$ (11,100.00)	$ (12,420.00)	$ (13,570.00)	$ (14,630.00)	$ (16,110.00)	$ (17,740.00)
TOTAL RIDER CE	**$ 11,080.00**	**$ 11,470.00**	**$ 13,118.00**	**$ 17,390.00**	**$ 21,550.00**	**$ 27,886.00**	**$ 34,802.00**	**$ 40,860.00**	**$ 44,106.00**	**$ 44,368.00**	**$ 43,260.00**
RIDER OSW [8]	$ 28,230.00	$ 28,680.00	$ 30,340.00	$ 40,260.00	$ 43,800.00	$ 50,030.00	$ 55,600.00	$ 74,590.00	$ 86,800.00	$ 89,110.00	$ 90,190.00
RIDER OSW - FUEL BENEFIT	$ (19,188.00)	$ (19,218.00)	$ (18,504.00)	$ (17,844.00)	$ (18,324.00)	$ (22,938.00)	$ (22,788.00)	$ (24,582.00)	$ (26,184.00)	$ (30,930.00)	$ (51,996.00)
RIDER OSW - REC PROXY VALUE	$ (24,180.00)	$ (24,072.00)	$ (24,042.00)	$ (22,416.00)	$ (20,820.00)	$ (19,674.00)	$ (22,782.00)	$ (20,574.00)	$ (19,818.00)	$ (18,918.00)	$ (19,440.00)
RIDER OSW - CAPACITY OFFSET	$ (5,980.00)	$ (6,080.00)	$ (6,350.00)	$ (6,370.00)	$ (5,690.00)	$ (5,390.00)	$ (5,580.00)	$ (5,850.00)	$ (6,100.00)	$ (6,370.00)	$ (9,680.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (21,118.00)**	**$ (20,690.00)**	**$ (18,556.00)**	**$ (6,370.00)**	**$ (1,034.00)**	**$ 2,028.00**	**$ 4,450.00**	**$ 23,584.00**	**$ 34,698.00**	**$ 32,892.00**	**$ 9,074.00**
NUCLEAR SMALL MODULAR REACTORS [9]	$ 3,630.00	$ 3,500.00	$ 14,710.00	$ 22,430.00	$ 31,480.00	$ 40,570.00	$ 47,920.00	$ 53,850.00	$ 57,260.00	$ 58,710.00	$ 56,030.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 56,208.00**	**$ 65,110.00**	**$ 89,264.00**	**$ 119,406.00**	**$ 144,036.00**	**$ 164,240.00**	**$ 182,578.00**	**$ 216,238.00**	**$ 242,822.00**	**$ 250,492.00**	**$ 230,788.00**
TOTAL	**$ 583,382.57**	**$ 635,489.25**	**$ 672,944.71**	**$ 732,648.71**	**$ 791,946.71**	**$ 829,280.71**	**$ 862,642.71**	**$ 908,886.71**	**$ 959,110.71**	**$ 1,006,740.71**	**$ 1,013,818.71**
CAGR (2019 BASE)							5.8%				5.4%
CAGR (MAY 2020 BASE)							6.7%				6.2%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[5] Inclusive of MATs and 111d compliance cost.
[6] Includes the cost of REC purchases, deficiency payments, and REC proxy value for RECs from Companyowned and contracted for resources.
[7] Includes specific Company-owned projects and PPAs proposed in 2020 and thereafter, along with generic solar, distributed solar, and storage.
[8] No assumptions modeled for exemptions to Riders OSW.
[9] 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 2039
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - VCEA 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 100.78	$ 113.32	$ 127.67	$ 142.15	$ 155.77
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 141.38	$ 180.28	$ 172.58	$ 181.96	$ 190.43
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 18.81	$ 16.68	$ 17.57	$ 16.68	$ 16.40
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 8.82	$ 6.36	$ 7.55	$ 7.33	$ 7.59	$ 7.79	$ 7.94
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 33.69	$ 22.82	$ 27.09	$ 25.63	$ 26.82
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.35	$ 2.77	$ 2.92	$ 4.28	$ 4.85
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 17.02	$ 18.67	$ 20.71	$ 24.50	$ 29.95
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 4.73	$ 1.40	$ 10.89	$ 7.70	$ 13.57	$ 16.57	$ 17.64	$ 19.63
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18	$ 9.86	$ 8.26	$ 14.42	$ 16.01	$ 13.87	$ 15.48	$ 16.73	$ 17.00
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12	$ 0.82	$ 0.97	$ 1.52	$ 2.01	$ 2.34	$ 2.30	$ 2.19	$ 2.12
A5 Environmental												
RIDER E	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.25	$ 3.56	$ 2.93	$ 3.19	$ 3.78
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.13	$ 18.79	$ 18.76	$ 18.76	$ 18.82	$ 25.34
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 27.85	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8.54	$ 14.64	$ 23.48
RPS Program-Related Resources												
RIDER RPS [5]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 30.11	$ 28.85	$ 44.29	$ 54.93	$ 62.62
RIDER CE [6]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.44	$ 17.97	$ 27.75	$ 41.62	$ 54.55	$ 67.77	$ 85.02
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.56)	$ (11.36)	$ (12.98)	$ (14.24)	$ (18.24)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.94)	$ (8.43)	$ (15.40)	$ (18.44)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (3.09)	$ (2.03)	$ (3.31)	$ (4.76)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.73**	**$ 10.68**	**$ 14.90**	**$ 20.23**	**$ 31.10**	**$ 34.82**	**$ 43.58**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 44.45	$ 58.31	$ 61.34	$ 56.11	$ 52.86
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14.58)	$ (20.05)	$ (18.79)	$ (18.67)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12.77)	$ (24.12)	$ (24.18)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4.83)	$ (7.57)	$ (6.87)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 44.45**	**$ 43.73**	**$ 23.68**	**$ 5.63**	**$ 3.14**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.34	$ 1.97	$ 6.83	$ 6.83	$ 6.83
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.36**	**$ 74.18**	**$ 89.80**	**$ 94.78**	**$ 105.91**	**$ 102.21**	**$ 116.17**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 645.77**	**$ 646.46**	**$ 723.72**	**$ 773.33**	**$ 811.22**	**$ 843.01**	**$ 904.28**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 169.08	$ 182.06	$ 194.74	$ 207.11	$ 216.70	$ 224.70	$ 233.41	$ 241.86	$ 250.07	$ 258.23
FUEL - RIDER A	$ 207.04	$ 206.42	$ 210.10	$ 219.90	$ 231.68	$ 236.53	$ 254.44	$ 276.53	$ 306.99	$ 329.88
FUEL SECURITIZATION	$ 15.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 8.10	$ 8.26	$ 8.43	$ 8.60	$ 8.76	$ 8.94	$ 8.94	$ 8.94	$ 8.94	$ 8.94
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 26.98	$ 25.85	$ 25.73	$ 26.91	$ 25.99	$ 26.10	$ 25.92	$ 26.99	$ 28.00	$ 26.47
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 4.72	$ 4.67	$ 4.53	$ 4.39	$ 4.27	$ 4.16	$ 4.07	$ 3.95	$ 3.84	$ 3.72
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 35.61	$ 38.12	$ 40.06	$ 40.02	$ 39.82	$ 38.90	$ 37.63	$ 36.20	$ 34.76	$ 33.32
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ 20.29	$ 19.69	$ 19.15	$ 18.59	$ 17.77	$ 17.12	$ 16.38	$ 15.75	$ 15.19	$ 14.63
STRATEGIC UNDERGROUND PLAN	$ 17.34	$ 16.23	$ 15.87	$ 15.51	$ 15.16	$ 14.79	$ 14.44	$ 14.09	$ 13.75	$ 13.43
RURAL BROADBAND	$ 2.06	$ 2.00	$ 1.93	$ 1.87	$ 1.81	$ 1.75	$ 1.68	$ 1.62	$ 1.55	$ 1.49
A5 Environmental										
RIDER E	$ 3.67	$ 2.96	$ 2.21	$ 2.56	$ 2.45	$ 2.35	$ 2.26	$ 2.16	$ 2.06	$ 1.91
RIDER CCR	$ 26.51	$ 26.70	$ 22.58	$ 30.55	$ 24.32	$ 24.20	$ 8.99	$ 1.81	$ 2.73	$ 1.15
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
GAS CT	$ 37.02	$ 52.51	$ 67.96	$ 78.55	$ 81.87	$ 88.03	$ 92.53	$ 90.12	$ 87.74	$ 85.40
RPS Program-Related Resources										
RIDER RPS [5]	$ 70.83	$ 79.99	$ 87.47	$ 95.63	$ 99.79	$ 104.45	$ 110.98	$ 120.77	$ 129.35	$ 138.11
RIDER CE [6]	$ 102.01	$ 120.18	$ 138.72	$ 156.79	$ 175.97	$ 194.88	$ 214.48	$ 232.99	$ 245.91	$ 255.89
RIDER CE - FUEL BENEFIT	$ (21.58)	$ (22.70)	$ (22.54)	$ (24.88)	$ (27.08)	$ (28.78)	$ (33.16)	$ (37.57)	$ (42.28)	$ (46.90)
RIDER CE - REC PROXY VALUE	$ (24.52)	$ (30.04)	$ (34.19)	$ (37.37)	$ (39.82)	$ (41.74)	$ (43.10)	$ (45.34)	$ (46.99)	$ (48.32)
RIDER CE - CAPACITY OFFSET	$ (6.01)	$ (6.84)	$ (8.83)	$ (10.79)	$ (12.23)	$ (14.03)	$ (15.35)	$ (16.54)	$ (18.31)	$ (20.64)
TOTAL RIDER CE	**$ 49.90**	**$ 60.61**	**$ 73.15**	**$ 83.74**	**$ 96.84**	**$ 110.32**	**$ 122.87**	**$ 133.54**	**$ 138.33**	**$ 140.03**
RIDER OSW [7]	$ 53.72	$ 56.82	$ 75.40	$ 82.04	$ 93.70	$ 104.15	$ 139.72	$ 162.58	$ 166.91	$ 168.94
RIDER OSW - FUEL BENEFIT	$ (18.62)	$ (16.46)	$ (14.33)	$ (14.96)	$ (18.87)	$ (18.74)	$ (20.60)	$ (22.25)	$ (26.81)	$ (45.11)
RIDER OSW - REC PROXY VALUE	$ (24.07)	$ (24.04)	$ (22.81)	$ (21.64)	$ (20.95)	$ (24.94)	$ (23.31)	$ (22.42)	$ (21.37)	$ (21.93)
RIDER OSW - CAPACITY OFFSET	$ (6.26)	$ (6.00)	$ (6.31)	$ (5.83)	$ (5.62)	$ (5.98)	$ (6.28)	$ (6.55)	$ (6.86)	$ (10.72)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 4.76**	**$ 10.31**	**$ 31.95**	**$ 39.62**	**$ 48.26**	**$ 54.49**	**$ 89.52**	**$ 111.36**	**$ 111.87**	**$ 91.18**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 6.59	$ 27.68	$ 42.20	$ 59.24	$ 76.33	$ 90.16	$ 101.32	$ 107.72	$ 110.46	$ 105.41
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 132.08**	**$ 178.59**	**$ 234.77**	**$ 278.23**	**$ 321.22**	**$ 359.43**	**$ 424.69**	**$ 473.39**	**$ 490.01**	**$ 474.73**
TOTAL	**$ 970.79**	**$ 1,028.64**	**$ 1,112.65**	**$ 1,197.37**	**$ 1,256.41**	**$ 1,311.59**	**$ 1,389.95**	**$ 1,458.00**	**$ 1,510.22**	**$ 1,517.89**
CAGR (2019 BASE)						5.3%				5.0%
CAGR (MAY 2020 BASE)						5.9%				5.5%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
Rate projections are not final. Rates are subject to regulatory approval.

LARGE GENERAL BILL PROJECTION - VCEA 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	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (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	$ 67,880.00	$ 76,330.00	$ 86,000.00	$ 95,750.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 141,384.00	$ 180,276.00	$ 172,584.00	$ 181,962.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,226.00	$ 18,809.25	$ 16,684.83	$ 17,569.35	$ 16,679.55
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 330.00	$ 474.00	$ 546.00	$ 624.00	$ 660.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 17,920.00	$ 12,130.00	$ 14,390.00	$ 13,630.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,250.00	$ 1,470.00	$ 1,550.00	$ 2,270.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 9,040.00	$ 9,930.00	$ 11,010.00	$ 13,020.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1,160.00	$ 360.00	$ 2,670.00	$ 1,890.00	$ 3,330.00	$ 4,070.00	$ 4,330.00
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00	$ 130.00	$ 150.00	$ 230.00	$ 300.00	$ 350.00	$ 340.00	$ 330.00
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	$ 1,730.00	$ 1,890.00	$ 1,560.00	$ 1,690.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,128.00	$ 18,786.00	$ 18,762.00	$ 18,762.00	$ 18,816.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 27,852.00	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,540.00	$ 7,780.00
RPS Program-Related Resources											
RIDER RPS [5]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 30,114.00	$ 28,848.00	$ 44,292.00	$ 54,930.00
RIDER CE [6]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 15,162.00	$ 22,844.00	$ 31,494.00	$ 40,410.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (8,562.00)	$ (11,364.00)	$ (12,984.00)	$ (14,244.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,936.00)	$ (8,430.00)	$ (15,402.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (1,570.00)	$ (1,050.00)	$ (1,690.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,420.00**	**$ 2,974.00**	**$ 9,030.00**	**$ 9,074.00**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 23,730.00	$ 31,130.00	$ 32,750.00	$ 29,960.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14,580.00)	$ (20,052.00)	$ (18,792.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,774.00)	$ (24,120.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,580.00)	$ (4,040.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 23,730.00**	**$ 16,550.00**	**$ (2,656.00)**	**$ (16,992.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180.00	$ 1,050.00	$ 3,630.00	$ 3,630.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 58,444.00**	**$ 49,422.00**	**$ 54,296.00**	**$ 50,642.00**
TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 434,195.69**	**$ 412,701.63**	**$ 461,469.96**	**$ 494,683.54**	**$ 510,858.06**	**$ 531,122.26**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

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]	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 104,930.00	$ 113,890.00	$ 122,630.00	$ 131,170.00	$ 139,510.00	$ 145,970.00	$ 151,360.00	$ 157,220.00	$ 162,920.00	$ 168,450.00	$ 173,940.00
FUEL - RIDER A	$ 190,428.00	$ 207,036.00	$ 206,418.00	$ 210,102.00	$ 219,900.00	$ 231,684.00	$ 236,526.00	$ 254,436.00	$ 276,528.00	$ 306,990.00	$ 329,880.00
FUEL SECURITIZATION	$ 16,399.86	$ 15,700.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 678.00	$ 690.00	$ 702.00	$ 720.00	$ 732.00	$ 744.00	$ 762.00	$ 762.00	$ 762.00	$ 762.00	$ 762.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 14,260.00	$ 14,340.00	$ 13,730.00	$ 13,690.00	$ 14,300.00	$ 13,810.00	$ 13,870.00	$ 13,760.00	$ 14,360.00	$ 14,870.00	$ 14,070.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 2,580.00	$ 2,510.00	$ 2,480.00	$ 2,410.00	$ 2,330.00	$ 2,270.00	$ 2,210.00	$ 2,160.00	$ 2,100.00	$ 2,040.00	$ 1,980.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 15,910.00	$ 18,930.00	$ 20,270.00	$ 21,290.00	$ 21,270.00	$ 21,160.00	$ 20,680.00	$ 20,000.00	$ 19,240.00	$ 18,480.00	$ 17,710.00
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ 4,820.00	$ 4,980.00	$ 4,830.00	$ 4,700.00	$ 4,560.00	$ 4,360.00	$ 4,200.00	$ 4,020.00	$ 3,870.00	$ 3,730.00	$ 3,590.00
RURAL BROADBAND	$ 320.00	$ 310.00	$ 300.00	$ 290.00	$ 280.00	$ 270.00	$ 260.00	$ 250.00	$ 240.00	$ 230.00	$ 220.00
A5 Environmental											
RIDER E	$ 2,010.00	$ 1,950.00	$ 1,580.00	$ 1,180.00	$ 1,360.00	$ 1,310.00	$ 1,250.00	$ 1,210.00	$ 1,160.00	$ 1,100.00	$ 1,020.00
RIDER CCR	$ 25,344.00	$ 26,514.00	$ 26,700.00	$ 22,584.00	$ 30,546.00	$ 24,318.00	$ 24,204.00	$ 8,994.00	$ 1,812.00	$ 2,730.00	$ 1,146.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ 12,490.00	$ 19,670.00	$ 27,910.00	$ 36,120.00	$ 41,750.00	$ 43,510.00	$ 46,790.00	$ 49,180.00	$ 47,900.00	$ 46,630.00	$ 45,390.00
RPS Program-Related Resources											
RIDER RPS [5]	$ 62,616.00	$ 70,830.00	$ 79,992.00	$ 87,474.00	$ 95,628.00	$ 99,786.00	$ 104,454.00	$ 110,976.00	$ 120,768.00	$ 129,354.00	$ 138,108.00
RIDER CE [6]	$ 51,490.00	$ 62,530.00	$ 74,266.00	$ 86,370.00	$ 98,226.00	$ 110,840.00	$ 123,414.00	$ 136,506.00	$ 149,038.00	$ 158,928.00	$ 167,302.00
RIDER CE - FUEL BENEFIT	$ (18,240.00)	$ (21,582.00)	$ (22,698.00)	$ (22,542.00)	$ (24,882.00)	$ (27,084.00)	$ (28,782.00)	$ (33,162.00)	$ (37,572.00)	$ (42,282.00)	$ (46,902.00)
RIDER CE - REC PROXY VALUE	$ (18,438.00)	$ (24,516.00)	$ (30,036.00)	$ (34,194.00)	$ (37,374.00)	$ (39,822.00)	$ (41,742.00)	$ (43,098.00)	$ (45,342.00)	$ (46,992.00)	$ (48,318.00)
RIDER CE - CAPACITY OFFSET	$ (2,420.00)	$ (3,050.00)	$ (3,450.00)	$ (4,500.00)	$ (5,460.00)	$ (6,210.00)	$ (7,130.00)	$ (7,790.00)	$ (8,380.00)	$ (9,280.00)	$ (10,470.00)
TOTAL RIDER CE	**$ 12,392.00**	**$ 13,382.00**	**$ 18,082.00**	**$ 25,134.00**	**$ 30,510.00**	**$ 37,724.00**	**$ 45,760.00**	**$ 52,456.00**	**$ 57,744.00**	**$ 60,374.00**	**$ 61,612.00**
RIDER OSW [7]	$ 28,230.00	$ 28,680.00	$ 30,340.00	$ 40,260.00	$ 43,800.00	$ 50,030.00	$ 55,610.00	$ 74,600.00	$ 86,800.00	$ 89,120.00	$ 90,200.00
RIDER OSW - FUEL BENEFIT	$ (18,666.00)	$ (18,624.00)	$ (16,464.00)	$ (14,328.00)	$ (14,958.00)	$ (18,870.00)	$ (18,744.00)	$ (20,604.00)	$ (22,248.00)	$ (26,808.00)	$ (45,108.00)
RIDER OSW - REC PROXY VALUE	$ (24,180.00)	$ (24,072.00)	$ (24,042.00)	$ (22,812.00)	$ (21,636.00)	$ (20,946.00)	$ (24,942.00)	$ (23,310.00)	$ (22,422.00)	$ (21,366.00)	$ (21,930.00)
RIDER OSW - CAPACITY OFFSET	$ (3,670.00)	$ (3,350.00)	$ (3,200.00)	$ (3,370.00)	$ (3,110.00)	$ (3,000.00)	$ (3,190.00)	$ (3,350.00)	$ (3,500.00)	$ (3,670.00)	$ (5,720.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (18,286.00)**	**$ (17,366.00)**	**$ (13,366.00)**	**$ (250.00)**	**$ 4,096.00**	**$ 7,214.00**	**$ 8,734.00**	**$ 27,336.00**	**$ 38,630.00**	**$ 37,276.00**	**$ 17,442.00**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 3,630.00	$ 3,500.00	$ 14,710.00	$ 22,430.00	$ 31,480.00	$ 40,570.00	$ 47,920.00	$ 53,850.00	$ 57,260.00	$ 58,710.00	$ 56,030.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 60,352.00**	**$ 70,346.00**	**$ 99,418.00**	**$ 134,788.00**	**$ 161,714.00**	**$ 185,294.00**	**$ 206,868.00**	**$ 244,618.00**	**$ 274,402.00**	**$ 285,714.00**	**$ 273,192.00**
TOTAL	**$ 574,084.57**	**$ 620,429.25**	**$ 650,530.71**	**$ 702,606.71**	**$ 761,814.71**	**$ 798,262.71**	**$ 832,542.71**	**$ 880,172.71**	**$ 928,856.71**	**$ 975,288.71**	**$ 986,462.71**
CAGR (2019 BASE)							5.5%				5.3%
CAGR (MAY 2020 BASE)							6.4%				6.0%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
Rate projections are not final. Rates are subject to regulatory approval.

RESIDENTIAL BILL PROJECTION - REC RPS ONLY WITHOUT EPA, 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 60.93	$ 60.93	$ 60.71	$ 60.72	$ 60.72	$ 60.72	$ 60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (0.47)	$ (0.43)	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	$ 12.91	$ 15.58	$ 19.40	$ 21.62	$ 24.31	$ 27.39	$ 30.50
FUEL - RIDER A	$ 23.25	$ 17.36	$ 17.02	$ 20.45	$ 35.38	$ 28.59	$ 20.74	$ 23.56	$ 29.85	$ 27.73	$ 29.24
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.37	$ 3.13	$ 2.78	$ 2.93	$ 2.78
DSM	$ 1.13	$ 1.13	$ 1.47	$ 1.31	$ 1.60	$ 1.84	$ 1.55	$ 1.85	$ 1.79	$ 1.85	$ 1.91
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.03	$ 0.03	$ 0.73	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	$ 14.51	$ 6.67	$ 6.58	$ 7.06	$ 4.78	$ 5.67	$ 5.37
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.49	$ 0.58	$ 0.61	$ 0.90
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 2.07	$ 0.93	$ 1.29	$ 3.57	$ 3.91	$ 4.34	$ 5.13
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1.16	$ 0.30	$ 3.22	$ 2.27	$ 4.01	$ 4.90	$ 5.21
STRATEGIC UNDERGROUND PLAN	$ 1.84	$ 1.40	$ 1.40	$ 2.14	$ 2.49	$ 1.99	$ 4.17	$ 4.63	$ 4.01	$ 4.48	$ 4.84
RURAL BROADBAND	$ -	$ -	$ -	$ 0.03	$ 0.19	$ 0.23	$ 0.42	$ 0.56	$ 0.65	$ 0.64	$ 0.61
A5 Environmental											
RIDER E	$ 1.99	$ 1.99	$ 1.67	$ 1.25	$ 1.95	$ 2.03	$ 1.35	$ 0.68	$ 0.75	$ 0.61	$ 0.67
RIDER CCR	$ -	$ -	$ -	$ 2.95	$ 2.96	$ 2.38	$ 1.19	$ 3.13	$ 3.13	$ 3.13	$ 3.14
RIDER RGGI	$ -	$ -	$ -	$ 2.39	$ -	$ 4.64	$ -	$ -	$ -	$ -	$ -
Additional Resources											
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.79	$ 3.07
RPS Program-Related Resources											
RIDER RPS [5]	$ -	$ -	$ -	$ 0.18	$ 1.81	$ 1.32	$ 4.69	$ 5.02	$ 4.81	$ 7.38	$ 9.16
RIDER CE [6]	$ -	$ -	$ -	$ 0.19	$ 1.67	$ 2.88	$ 4.10	$ 6.07	$ 6.29	$ 8.15	$ 9.29
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.38)	$ (1.15)	$ (1.22)	$ (1.43)	$ (1.89)	$ (2.10)	$ (2.30)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.16)	$ (1.40)	$ (2.49)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.03)	$ (0.03)	$ -	$ (0.96)	$ (0.69)	$ (0.45)	$ (0.63)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 1.26**	**$ 1.70**	**$ 2.89**	**$ 3.69**	**$ 2.55**	**$ 4.20**	**$ 3.87**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 1.45	$ 4.74	$ 8.63	$ 9.07	$ 11.89	$ 12.51	$ 11.44
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.43)	$ (3.34)	$ (3.13)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.13)	$ (4.02)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.99)	$ (1.54)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.45**	**$ 4.74**	**$ 8.63**	**$ 9.07**	**$ 9.46**	**$ 6.05**	**$ 2.75**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.07	$ 0.41	$ 1.43	$ 1.43
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 4.52**	**$ 7.76**	**$ 16.21**	**$ 17.84**	**$ 17.24**	**$ 19.07**	**$ 17.20**
TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.54**	**$ 122.72**	**$ 140.22**	**$ 134.17**	**$ 140.18**	**$ 151.13**	**$ 158.50**	**$ 165.85**	**$ 171.28**
CAGR (2019 BASE)											
CAGR (MAY 2020 BASE)											

RESIDENTIAL Schedule 1 (1,000 kWh)	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]	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72	$ 60.72
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
TRANSMISSION - RIDER T	$ 33.42	$ 36.28	$ 39.06	$ 41.78	$ 44.44	$ 46.50	$ 48.21	$ 50.08	$ 51.89	$ 53.66	55.41
FUEL - RIDER A	$ 30.86	$ 33.76	$ 33.61	$ 34.22	$ 35.77	$ 38.07	$ 39.00	$ 41.94	$ 45.80	$ 50.52	47.48
FUEL SECURITIZATION	$ 2.73	$ 2.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
DSM	$ 1.94	$ 1.98	$ 2.02	$ 2.06	$ 2.10	$ 2.14	$ 2.19	$ 2.19	$ 2.19	$ 2.19	2.19
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Generation Infrastructure											
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 5.62	$ 5.65	$ 5.41	$ 5.39	$ 5.63	$ 5.44	$ 5.47	$ 5.43	$ 5.66	$ 5.86	5.54
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 1.02	$ 0.99	$ 0.98	$ 0.95	$ 0.92	$ 0.90	$ 0.87	$ 0.85	$ 0.83	$ 0.80	0.78
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 6.27	$ 7.46	$ 7.99	$ 8.39	$ 8.38	$ 8.34	$ 8.15	$ 7.88	$ 7.58	$ 7.28	6.98
Distribution Infrastructure [4]											
GRID TRANSFORMATION PLAN	$ 5.80	$ 6.00	$ 5.82	$ 5.66	$ 5.49	$ 5.25	$ 5.06	$ 4.84	$ 4.65	$ 4.49	4.32
STRATEGIC UNDERGROUND PLAN	$ 4.92	$ 5.01	$ 4.69	$ 4.59	$ 4.49	$ 4.38	$ 4.28	$ 4.17	$ 4.07	$ 3.98	3.88
RURAL BROADBAND	$ 0.59	$ 0.57	$ 0.56	$ 0.54	$ 0.52	$ 0.51	$ 0.49	$ 0.47	$ 0.45	$ 0.43	0.42
A5 Environmental											
RIDER E	$ 0.79	$ 0.77	$ 0.62	$ 0.46	$ 0.54	$ 0.51	$ 0.49	$ 0.47	$ 0.45	$ 0.43	0.40
RIDER CCR	$ 4.22	$ 4.42	$ 4.45	$ 3.76	$ 5.09	$ 4.05	$ 4.03	$ 1.50	$ 0.30	$ 0.46	0.19
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Additional Resources											
GAS CT	$ 4.92	$ 7.76	$ 11.00	$ 14.23	$ 16.45	$ 17.15	$ 18.44	$ 19.38	$ 18.88	$ 18.38	17.89
RPS Program-Related Resources											
RIDER RPS [5]	$ 10.44	$ 11.81	$ 13.34	$ 14.59	$ 15.95	$ 16.64	$ 17.50	$ 18.80	$ 20.74	$ 22.48	23.44
RIDER CE [6]	$ 11.22	$ 13.14	$ 15.21	$ 17.33	$ 19.58	$ 22.07	$ 24.71	$ 27.73	$ 30.79	$ 33.34	35.54
RIDER CE - FUEL BENEFIT	$ (2.86)	$ (3.38)	$ (3.55)	$ (3.52)	$ (3.87)	$ (4.21)	$ (4.46)	$ (5.13)	$ (5.80)	$ (6.51)	(7.22)
RIDER CE - REC PROXY VALUE	$ (2.98)	$ (3.84)	$ (4.70)	$ (5.35)	$ (5.84)	$ (6.20)	$ (6.48)	$ (6.67)	$ (7.01)	$ (7.25)	(7.44)
RIDER CE - CAPACITY OFFSET	$ (1.01)	$ (1.38)	$ (1.56)	$ (2.00)	$ (2.43)	$ (2.75)	$ (3.15)	$ (3.45)	$ (3.71)	$ (4.09)	(4.61)
TOTAL RIDER CE	**$ 4.38**	**$ 4.54**	**$ 5.39**	**$ 6.46**	**$ 7.43**	**$ 8.92**	**$ 10.62**	**$ 12.49**	**$ 14.28**	**$ 15.49**	**16.29**
RIDER OSW [7]	$ 10.57	$ 9.88	$ 9.38	$ 11.54	$ 11.80	$ 14.07	$ 17.88	$ 27.22	$ 33.56	$ 35.61	35.70
RIDER OSW - FUEL BENEFIT	$ (3.11)	$ (3.10)	$ (2.74)	$ (2.39)	$ (2.39)	$ (2.40)	$ (2.39)	$ (2.62)	$ (2.97)	$ (4.47)	(7.52)
RIDER OSW - REC PROXY VALUE	$ (4.03)	$ (4.01)	$ (4.01)	$ (3.80)	$ (3.61)	$ (3.39)	$ (3.18)	$ (2.97)	$ (2.85)	$ (2.81)	(3.66)
RIDER OSW - CAPACITY OFFSET	$ (1.40)	$ (1.28)	$ (1.22)	$ (1.29)	$ (1.19)	$ (0.98)	$ (0.93)	$ (0.98)	$ (1.02)	$ (1.27)	(2.19)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ 2.03**	**$ 1.48**	**$ 1.40**	**$ 4.06**	**$ 4.61**	**$ 7.30**	**$ 11.39**	**$ 20.65**	**$ 26.72**	**$ 27.07**	**22.34**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 1.43	$ 1.38	$ 5.80	$ 8.84	$ 12.41	$ 15.99	$ 18.89	$ 21.22	$ 22.56	$ 23.14	22.08
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 18.28**	**$ 19.22**	**$ 25.93**	**$ 33.95**	**$ 40.40**	**$ 48.85**	**$ 58.39**	**$ 73.16**	**$ 84.30**	**$ 88.18**	**84.14**
TOTAL	**$ 182.10**	**$ 193.19**	**$ 202.85**	**$ 216.71**	**$ 230.94**	**$ 242.80**	**$ 255.79**	**$ 273.08**	**$ 287.79**	**$ 297.37**	**290.35**
CAGR (2019 BASE)							4.7%				4.4%
CAGR (MAY 2020 BASE)							5.2%				4.8%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
Rate projections are not final. Rates are subject to regulatory approval.

SMALL GENERAL BILL PROJECTION - REC RPS ONLY 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 272.78	$ 272.78	$ 272.78	$ 272.78	$ 266.31	$ 266.31	$ 259.72	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (3.27)	$ (3.00)	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	$ 58.84	$ 65.08	$ 90.40	$ 100.78	$ 113.32	$ 127.67	$ 142.15	$ 155.77
FUEL - RIDER A	$ 139.52	$ 104.14	$ 102.13	$ 122.69	$ 212.27	$ 171.52	$ 124.41	$ 141.38	$ 179.09	$ 166.35	$ 175.43	$ 185.15
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20.23	$ 18.81	$ 16.68	$ 17.57	$ 16.68	$ 16.40
DSM	$ 5.33	$ 5.33	$ 6.49	$ 6.22	$ 6.42	$ 8.82	$ 6.36	$ 7.55	$ 7.33	$ 7.59	$ 7.79	$ 7.94
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16	$ 0.16	$ 4.39	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	$ 59.26	$ 27.33	$ 26.51	$ 33.69	$ 22.82	$ 27.09	$ 25.63	$ 26.82
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.35	$ 2.77	$ 2.92	$ 4.28	$ 4.85
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 8.24	$ 4.46	$ 5.22	$ 17.02	$ 18.67	$ 20.71	$ 24.50	$ 29.95
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 4.73	$ 1.40	$ 10.89	$ 7.70	$ 13.57	$ 16.57	$ 17.64	$ 19.63
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18	$ 9.86	$ 8.26	$ 14.42	$ 16.01	$ 13.87	$ 15.48	$ 16.73	$ 17.00
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12	$ 0.82	$ 0.97	$ 1.52	$ 2.01	$ 2.34	$ 2.30	$ 2.19	$ 2.12
A5 Environmental												
RIDER E	$ 9.44	$ 9.44	$ 7.48	$ 5.99	$ 7.76	$ 9.77	$ 5.48	$ 3.25	$ 3.56	$ 2.93	$ 3.19	$ 3.78
RIDER CCR	$ -	$ -	$ -	$ 17.67	$ 17.73	$ 14.26	$ 7.13	$ 18.79	$ 18.76	$ 18.76	$ 18.82	$ 25.34
RIDER RGGI	$ -	$ -	$ -	$ 14.36	$ -	$ 27.85	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8.54	$ 14.64	$ 23.48
RPS Program-Related Resources												
RIDER RPS [5]	$ -	$ -	$ -	$ 1.09	$ 10.86	$ 7.90	$ 28.13	$ 30.11	$ 28.85	$ 44.30	$ 54.94	$ 62.63
RIDER CE [6]	$ -	$ -	$ -	$ 0.92	$ 7.18	$ 14.44	$ 17.97	$ 27.75	$ 29.00	$ 38.44	$ 44.69	$ 55.51
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2.29)	$ (6.57)	$ (7.29)	$ (8.56)	$ (11.31)	$ (12.59)	$ (13.81)	$ (17.14)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.94)	$ (8.39)	$ (14.93)	$ (17.88)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.13)	$ (0.14)	$ -	$ (4.29)	$ (3.09)	$ (2.02)	$ (2.80)	$ (4.52)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 4.76**	**$ 7.73**	**$ 10.68**	**$ 14.90**	**$ 7.67**	**$ 15.45**	**$ 13.16**	**$ 15.97**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 5.80	$ 22.73	$ 35.36	$ 44.45	$ 58.31	$ 61.34	$ 56.11	$ 51.83
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14.58)	$ (20.05)	$ (18.79)	$ (18.67)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12.77)	$ (24.12)	$ (24.18)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4.83)	$ (7.57)	$ (6.87)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5.80**	**$ 22.73**	**$ 35.36**	**$ 44.45**	**$ 43.73**	**$ 23.68**	**$ 5.63**	**$ 2.12**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.34	$ 1.97	$ 6.83	$ 6.83	$ 6.83
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.42**	**$ 38.36**	**$ 74.18**	**$ 89.80**	**$ 82.22**	**$ 90.26**	**$ 80.56**	**$ 87.55**
TOTAL	**$ 573.95**	**$ 532.40**	**$ 542.13**	**$ 587.62**	**$ 670.55**	**$ 645.77**	**$ 646.46**	**$ 723.72**	**$ 759.57**	**$ 789.34**	**$ 814.82**	**$ 870.38**
CAGR (2019 BASE)												
CAGR (MAY 2020 BASE)												

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 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
DISTRIBUTION & GENERATION (BASE) [1]	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59	$ 264.59
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 169.08	$ 182.06	$ 194.74	$ 207.11	$ 216.70	$ 224.70	$ 233.41	$ 241.86	$ 250.07	$ 258.23
FUEL - RIDER A	$ 202.56	$ 201.66	$ 205.30	$ 214.61	$ 228.41	$ 233.99	$ 251.63	$ 274.81	$ 303.12	$ 284.90
FUEL SECURITIZATION	$ 15.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 8.10	$ 8.26	$ 8.43	$ 8.60	$ 8.76	$ 8.94	$ 8.94	$ 8.94	$ 8.94	$ 8.94
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 26.98	$ 25.85	$ 25.73	$ 26.91	$ 25.99	$ 26.10	$ 25.92	$ 26.99	$ 28.00	$ 26.47
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 4.72	$ 4.67	$ 4.53	$ 4.39	$ 4.27	$ 4.16	$ 4.07	$ 3.95	$ 3.84	$ 3.72
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 35.61	$ 38.12	$ 40.06	$ 40.02	$ 39.82	$ 38.90	$ 37.63	$ 36.20	$ 34.76	$ 33.32
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ 20.29	$ 19.69	$ 19.15	$ 18.59	$ 17.77	$ 17.12	$ 16.38	$ 15.75	$ 15.19	$ 14.63
STRATEGIC UNDERGROUND PLAN	$ 17.34	$ 16.23	$ 15.87	$ 15.51	$ 15.16	$ 14.79	$ 14.44	$ 14.09	$ 13.75	$ 13.43
RURAL BROADBAND	$ 2.06	$ 2.00	$ 1.93	$ 1.87	$ 1.81	$ 1.75	$ 1.68	$ 1.62	$ 1.55	$ 1.49
A5 Environmental										
RIDER E	$ 3.67	$ 2.96	$ 2.21	$ 2.56	$ 2.45	$ 2.35	$ 2.26	$ 2.16	$ 2.06	$ 1.91
RIDER CCR	$ 26.51	$ 26.70	$ 22.58	$ 30.55	$ 24.32	$ 24.20	$ 8.99	$ 1.81	$ 2.73	$ 1.15
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources										
GAS CT	$ 37.02	$ 52.51	$ 67.96	$ 78.55	$ 81.87	$ 88.03	$ 92.53	$ 90.12	$ 87.74	$ 85.40
RPS Program-Related Resources										
RIDER RPS [5]	$ 70.86	$ 80.03	$ 87.52	$ 95.68	$ 99.86	$ 105.00	$ 112.81	$ 124.46	$ 134.87	$ 140.65
RIDER CE [6]	$ 66.35	$ 77.93	$ 89.89	$ 102.46	$ 116.28	$ 130.85	$ 147.30	$ 163.93	$ 178.49	$ 191.43
RIDER CE - FUEL BENEFIT	$ (20.27)	$ (21.32)	$ (21.12)	$ (23.24)	$ (25.24)	$ (26.76)	$ (30.76)	$ (34.79)	$ (39.07)	$ (43.29)
RIDER CE - REC PROXY VALUE	$ (23.03)	$ (28.22)	$ (32.11)	$ (35.02)	$ (37.19)	$ (38.88)	$ (40.04)	$ (42.05)	$ (43.49)	$ (44.63)
RIDER CE - CAPACITY OFFSET	$ (6.19)	$ (6.99)	$ (8.96)	$ (10.89)	$ (12.31)	$ (14.09)	$ (15.42)	$ (16.58)	$ (18.31)	$ (20.61)
TOTAL RIDER CE	**$ 16.86**	**$ 21.40**	**$ 27.70**	**$ 33.31**	**$ 41.54**	**$ 51.11**	**$ 61.07**	**$ 70.51**	**$ 77.61**	**$ 82.90**
RIDER OSW [7]	$ 48.42	$ 45.98	$ 56.58	$ 57.85	$ 68.98	$ 87.65	$ 133.43	$ 164.54	$ 174.59	$ 175.02
RIDER OSW - FUEL BENEFIT	$ (18.62)	$ (16.46)	$ (14.33)	$ (14.35)	$ (14.41)	$ (14.32)	$ (15.74)	$ (17.81)	$ (26.81)	$ (45.11)
RIDER OSW - REC PROXY VALUE	$ (24.07)	$ (24.04)	$ (22.81)	$ (21.64)	$ (20.31)	$ (19.05)	$ (17.80)	$ (17.12)	$ (16.83)	$ (21.93)
RIDER OSW - CAPACITY OFFSET	$ (6.26)	$ (6.00)	$ (6.31)	$ (5.83)	$ (4.82)	$ (4.57)	$ (4.80)	$ (5.00)	$ (6.22)	$ (10.72)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (0.54)**	**$ (0.52)**	**$ 13.13**	**$ 16.03**	**$ 29.44**	**$ 49.72**	**$ 95.09**	**$ 124.60**	**$ 124.73**	**$ 97.26**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 6.59	$ 27.68	$ 42.20	$ 59.24	$ 76.33	$ 90.16	$ 101.32	$ 107.72	$ 110.46	$ 105.41
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 93.77**	**$ 128.59**	**$ 170.55**	**$ 204.26**	**$ 247.18**	**$ 296.00**	**$ 370.30**	**$ 427.28**	**$ 447.68**	**$ 426.22**
TOTAL	**$ 928.00**	**$ 973.88**	**$ 1,043.62**	**$ 1,118.12**	**$ 1,179.09**	**$ 1,245.63**	**$ 1,332.75**	**$ 1,410.18**	**$ 1,464.01**	**$ 1,424.40**
CAGR (2019 BASE)						5.0%				4.6%
CAGR (MAY 2020 BASE)						5.6%				5.1%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 2039
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LARGE GENERAL BILL PROJECTION - REC RPS ONLY 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
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	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ (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	$ 67,880.00	$ 76,330.00	$ 86,000.00
FUEL - RIDER A	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	$ 212,274.00	$ 171,522.00	$ 124,410.00	$ 141,384.00	$ 179,088.00	$ 166,350.00
FUEL SECURITIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,226.00	$ 18,809.25	$ 16,684.83	$ 17,569.35
DSM	$ 150.00	$ 150.00	$ 144.00	$ 60.00	$ 102.00	$ 168.00	$ 330.00	$ 474.00	$ 546.00	$ 624.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00	$ 162.00	$ 4,392.00	$ -	$ -	$ -	$ -
Generation Infrastructure										
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	$ 36,660.00	$ 15,480.00	$ 15,390.00	$ 17,920.00	$ 12,130.00	$ 14,390.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,250.00	$ 1,470.00	$ 1,550.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	$ 5,150.00	$ 2,030.00	$ 3,110.00	$ 9,040.00	$ 9,930.00	$ 11,010.00
Distribution Infrastructure [4]										
GRID TRANSFORMATION PLAN	$ -	$ -	$ -	$ -	$ 1,160.00	$ 360.00	$ 2,670.00	$ 1,890.00	$ 3,330.00	$ 4,070.00
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00	$ 130.00	$ 150.00	$ 230.00	$ 300.00	$ 350.00	$ 340.00
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	$ 1,730.00	$ 1,890.00	$ 1,560.00
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	$ 17,730.00	$ 14,256.00	$ 7,128.00	$ 18,786.00	$ 18,762.00	$ 18,762.00
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	$ -	$ 27,852.00	$ -	$ -	$ -	$ -
Additional Resources										
GAS CT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,540.00
RPS Program-Related Resources										
RIDER RPS [5]	$ -	$ -	$ -	$ 1,092.00	$ 10,860.00	$ 7,896.00	$ 28,134.00	$ 30,114.00	$ 28,848.00	$ 44,304.00
RIDER CE [6]	$ -	$ -	$ -	$ 480.00	$ 5,002.00	$ 7,720.00	$ 11,120.00	$ 15,162.00	$ 16,432.00	$ 23,296.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (2,286.00)	$ (6,102.00)	$ (7,290.00)	$ (8,562.00)	$ (11,310.00)	$ (12,588.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,936.00)	$ (8,388.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (80.00)	$ (74.00)	$ -	$ (2,180.00)	$ (1,570.00)	$ (1,030.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 2,636.00**	**$ 1,544.00**	**$ 3,830.00**	**$ 4,420.00**	**$ (3,384.00)**	**$ 1,290.00**
RIDER OSW [7]	$ -	$ -	$ -	$ -	$ 3,470.00	$ 10,780.00	$ 20,750.00	$ 23,730.00	$ 31,130.00	$ 32,750.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14,580.00)	$ (20,052.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,774.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,580.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,470.00**	**$ 10,780.00**	**$ 20,750.00**	**$ 23,730.00**	**$ 16,550.00**	**$ (2,656.00)**
NUCLEAR SMALL MODULAR REACTORS [8]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180.00	$ 1,050.00	$ 3,630.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 16,966.00**	**$ 20,220.00**	**$ 52,714.00**	**$ 58,444.00**	**$ 43,064.00**	**$ 46,568.00**
TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 313,786.69**	**$ 370,696.69**	**$ 455,896.60**	**$ 434,195.69**	**$ 412,701.63**	**$ 461,469.96**	**$ 487,137.54**	**$ 496,896.06**
CAGR (2019 BASE)										
CAGR (MAY 2020 BASE)										

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	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	2037 DEC 2037	2038 DEC 2038	2039 DEC 2039
DISTRIBUTION & GENERATION (BASE) [1]	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71	$ 123,562.71
TRIENNIAL REVIEW - VOLUNTARY CUSTOMER REFUND [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSMISSION - RIDER T	$ 95,750.00	$ 104,930.00	$ 113,890.00	$ 122,630.00	$ 131,170.00	$ 139,510.00	$ 145,970.00	$ 151,360.00	$ 157,220.00	$ 162,920.00	$ 168,450.00	$ 173,940.00
FUEL - RIDER A	$ 175,428.00	$ 185,148.00	$ 202,560.00	$ 201,660.00	$ 205,302.00	$ 214,614.00	$ 228,408.00	$ 233,994.00	$ 251,628.00	$ 274,812.00	$ 303,120.00	$ 284,904.00
FUEL SECURITIZATION	$ 16,679.55	$ 16,399.86	$ 15,700.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM	$ 660.00	$ 678.00	$ 690.00	$ 702.00	$ 720.00	$ 732.00	$ 744.00	$ 762.00	$ 762.00	$ 762.00	$ 762.00	$ 762.00
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Infrastructure												
GENERATION RIDERS APPROVED PRIOR TO 2020 [3]	$ 13,630.00	$ 14,260.00	$ 14,340.00	$ 13,730.00	$ 13,690.00	$ 14,300.00	$ 13,810.00	$ 13,870.00	$ 13,760.00	$ 14,360.00	$ 14,870.00	$ 14,070.00
LIQUIFIED NATURAL GAS FACILITIES - LNG	$ 2,270.00	$ 2,580.00	$ 2,510.00	$ 2,480.00	$ 2,410.00	$ 2,330.00	$ 2,270.00	$ 2,210.00	$ 2,160.00	$ 2,100.00	$ 2,040.00	$ 1,980.00
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ 13,020.00	$ 15,910.00	$ 18,930.00	$ 20,270.00	$ 21,290.00	$ 21,270.00	$ 21,160.00	$ 20,680.00	$ 20,000.00	$ 19,240.00	$ 18,480.00	$ 17,710.00
Distribution Infrastructure [4]												
GRID TRANSFORMATION PLAN	$ 4,330.00	$ 4,820.00	$ 4,980.00	$ 4,830.00	$ 4,700.00	$ 4,560.00	$ 4,360.00	$ 4,200.00	$ 4,020.00	$ 3,870.00	$ 3,730.00	$ 3,590.00
RURAL BROADBAND	$ 330.00	$ 320.00	$ 310.00	$ 300.00	$ 290.00	$ 280.00	$ 270.00	$ 260.00	$ 250.00	$ 240.00	$ 230.00	$ 220.00
A5 Environmental												
RIDER E	$ 1,690.00	$ 2,010.00	$ 1,950.00	$ 1,580.00	$ 1,180.00	$ 1,360.00	$ 1,310.00	$ 1,250.00	$ 1,210.00	$ 1,160.00	$ 1,100.00	$ 1,020.00
RIDER CCR	$ 18,816.00	$ 25,344.00	$ 26,514.00	$ 26,700.00	$ 22,584.00	$ 30,546.00	$ 24,318.00	$ 24,204.00	$ 8,994.00	$ 1,812.00	$ 2,730.00	$ 1,146.00
RIDER RGGI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional Resources												
GAS CT	$ 7,780.00	$ 12,490.00	$ 19,670.00	$ 27,910.00	$ 36,120.00	$ 41,750.00	$ 43,510.00	$ 46,790.00	$ 49,180.00	$ 47,900.00	$ 46,630.00	$ 45,390.00
RPS Program-Related Resources												
RIDER RPS [5]	$ 54,936.00	$ 62,628.00	$ 70,860.00	$ 80,034.00	$ 87,522.00	$ 95,682.00	$ 99,864.00	$ 105,000.00	$ 112,812.00	$ 124,458.00	$ 134,874.00	$ 140,646.00
RIDER CE [6]	$ 28,750.00	$ 38,408.00	$ 48,248.00	$ 58,632.00	$ 69,516.00	$ 80,752.00	$ 92,926.00	$ 105,684.00	$ 119,712.00	$ 133,848.00	$ 147,268.00	$ 159,896.00
RIDER CE - FUEL BENEFIT	$ (13,806.00)	$ (17,136.00)	$ (20,274.00)	$ (21,324.00)	$ (21,120.00)	$ (23,244.00)	$ (25,236.00)	$ (26,760.00)	$ (30,762.00)	$ (34,788.00)	$ (39,072.00)	$ (43,290.00)
RIDER CE - REC PROXY VALUE	$ (14,934.00)	$ (17,880.00)	$ (23,028.00)	$ (28,218.00)	$ (32,112.00)	$ (35,016.00)	$ (37,194.00)	$ (38,880.00)	$ (40,044.00)	$ (42,048.00)	$ (43,494.00)	$ (44,628.00)
RIDER CE - CAPACITY OFFSET	$ (1,430.00)	$ (2,300.00)	$ (3,130.00)	$ (3,540.00)	$ (4,550.00)	$ (5,510.00)	$ (6,250.00)	$ (7,160.00)	$ (7,830.00)	$ (8,410.00)	$ (9,290.00)	$ (10,460.00)
TOTAL RIDER CE	**$ (1,420.00)**	**$ 1,092.00**	**$ 1,816.00**	**$ 5,550.00**	**$ 11,734.00**	**$ 16,982.00**	**$ 24,246.00**	**$ 32,884.00**	**$ 41,076.00**	**$ 48,602.00**	**$ 55,412.00**	**$ 61,518.00**
RIDER OSW [7]	$ 29,960.00	$ 27,680.00	$ 25,850.00	$ 24,550.00	$ 30,210.00	$ 30,880.00	$ 36,830.00	$ 46,800.00	$ 71,240.00	$ 87,850.00	$ 93,220.00	$ 93,440.00
RIDER OSW - FUEL BENEFIT	$ (18,792.00)	$ (18,666.00)	$ (18,624.00)	$ (16,464.00)	$ (14,328.00)	$ (14,352.00)	$ (14,412.00)	$ (14,316.00)	$ (15,738.00)	$ (17,814.00)	$ (26,808.00)	$ (45,108.00)
RIDER OSW - REC PROXY VALUE	$ (24,120.00)	$ (24,180.00)	$ (24,072.00)	$ (24,042.00)	$ (22,812.00)	$ (21,636.00)	$ (20,310.00)	$ (19,050.00)	$ (17,802.00)	$ (17,124.00)	$ (16,830.00)	$ (21,930.00)
RIDER OSW - CAPACITY OFFSET	$ (4,040.00)	$ (3,670.00)	$ (3,350.00)	$ (3,200.00)	$ (3,370.00)	$ (3,110.00)	$ (2,570.00)	$ (2,440.00)	$ (2,560.00)	$ (2,670.00)	$ (3,320.00)	$ (5,720.00)
TOTAL OFFSHORE WIND (3 PROJECTS TOTALING 5,987 MW)	**$ (16,992.00)**	**$ (18,836.00)**	**$ (20,196.00)**	**$ (19,156.00)**	**$ (10,300.00)**	**$ (8,218.00)**	**$ (462.00)**	**$ 10,994.00**	**$ 35,140.00**	**$ 50,242.00**	**$ 46,262.00**	**$ 20,682.00**
NUCLEAR SMALL MODULAR REACTORS [8]	$ 3,630.00	$ 3,630.00	$ 3,500.00	$ 14,710.00	$ 22,430.00	$ 31,480.00	$ 40,570.00	$ 47,920.00	$ 53,850.00	$ 57,260.00	$ 58,710.00	$ 56,030.00
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 40,154.00**	**$ 48,514.00**	**$ 55,980.00**	**$ 81,138.00**	**$ 111,386.00**	**$ 135,926.00**	**$ 164,218.00**	**$ 196,798.00**	**$ 242,878.00**	**$ 280,562.00**	**$ 295,258.00**	**$ 278,876.00**
TOTAL	**$ 514,100.26**	**$ 556,966.57**	**$ 601,587.25**	**$ 627,492.71**	**$ 674,404.71**	**$ 730,740.71**	**$ 773,910.71**	**$ 819,940.71**	**$ 875,624.71**	**$ 933,300.71**	**$ 980,962.71**	**$ 947,170.71**
CAGR (2019 BASE)								5.4%				5.1%
CAGR (MAY 2020 BASE)								6.3%				5.8%

[1] Publicly available, annualized tariff rates consistent with the final order in Case No. PUR-2023-00101. No future changes modeled.
[2] Rate in 2025 and thereafter, will be determined in future case.
[3] Reflects Riders B, R, S, W, BW, GV, US-2, US-3, and US-4 through 2023. Riders R, S, and W rolled into base rates effective July 1, 2023.
[4] Includes all approved (as of August 2024) and projected phases of distribution infrastructure. Rider GT & Rider U proposed for consolidation.
[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 4B: North Carolina Bill Analysis

Filed in North Carolina only.

Appendix 5A: Environmental Regulations

Historically, coal-fired and natural gas-fired generation have played an important role in maintaining reliability. These units can be dispatched quickly in times of high demand, such as cold winter weather. However, recent state and federal policy changes affect the dispatch and continue 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 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, oil, and gas-fired steam generating units will 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 investments 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 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 Table 1 below.

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 will impact 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) sets forth emission guidelines for existing coal, oil and gas fossil fuel-fired steam electric steam generating units. The final rule was published in the Federal Register on May 9, 2024. Under Section 111(d), coal units have the following options to comply: (1) retire by January 1, 2032; (2) transition to 40% natural gas co-firing by 2030; or (3) install carbon capture and sequestration ("CCS") 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, but must cease using coal entirely by January 1, 2030. Units that convert to 100% gas or install CCS do not have a mandated retirement date. EPA has indicated it plans to include existing gas and oil fired combustion turbines under section 111(d) in a future rulemaking. States have flexibility to consider a range of approaches to achieve the emission reductions identified through BSER.

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 CO_2 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 CO_2 emission standard upon startup but do not require CCS. Units operating above 40% capacity factor have an accompanying CO_2 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 emission standard determined by an 88.4% percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification). 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.

Mercury and Air Toxics Standards Rule ("MATS Rule")

The MATS Rule generally applies to coal and oil-fired generation units, but the recent changes only affect 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.

Ozone National Ambient Air Quality Standards ("NAAQS")

The NAAQS govern ground-level ozone forming pollutants, including nitric oxide ("NO_x") 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 summer 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. On June 27, 2024, the U.S. Supreme Court, issued an order to stay the EPA's FIP. The stay 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").

Proposed Revisions to the Prevention of Significant Deterioration and New Source Review Regulations for Greenhouse Gases

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a prevention of significant deterioration permit for greenhouse gas emissions is triggered only if such permitting requirements are first triggered by non-greenhouse gas, or conventional, pollutants that are regulated by the new source review program and exceed a significant emissions rate of 75,000 tons per year of CO_2 equivalent emissions. There is no expected timeframe for the final rule.

New Federal Vehicle Emission Standards

On June 13, 2024, the EPA published a final rule applicable to new vehicle standards for light, medium, and heavy-duty vehicles for model year 2027 and beyond. The final rule increases the stringency of the standard year-over-year on a phase-in approach. Through 2055, the EPA projects that the proposed standards would cumulatively avoid nearly 7.7 billion tons of CO_2 emissions and would also deliver significant health benefits by reducing fine particulate matter.

Particulate Emission Standards

On March 6, 2024, EPA released a final rule lowering the primary annual National Ambient Air Quality Standard (NAAQs) for fine particulate matter ($PM_{2.5}$) 9.0 ug/m^3. EPA retained the other PM NAAQs at their current levels, including the 24-hour $PM_{2.5}$ NAAQS.

Coal Combustion Residuals

The Company currently operates inactive ash ponds, existing ash ponds, and coal combustion residual ("CCR") landfills at eight different facilities. In April 2015, the EPA enacted a final rule regulating (i) CCR landfills; (ii) existing ash ponds that still receive and manage CCRs; and (iii) inactive ash ponds that do not receive, but still store, CCRs. This rule created a legal obligation for the Company to retrofit or close all inactive and existing ash ponds over a certain period of time, and to perform required monitoring, corrective action, and post-closure care activities as necessary. Since the rule was enacted, the EPA has reconsidered portions of the rule in response to litigation and petitions for reconsideration. In May 2024, the EPA promulgated a rule that regulates certain inactive or previously closed surface impoundments, landfills, or other areas that contain CCR located at retired generating stations after October 2015. The rule will require evaluation to identify potential areas of ash placement at subject facilities. If additional areas of ash are identified, the rule creates a legal obligation to formally close the ash areas and to perform required monitoring, corrective action, and post-closure care activities as necessary.

<u>Clean Water Act</u>

The Clean Water Act ("CWA") is a comprehensive program that uses a broad range of regulatory tools to protect the waters of the United States, including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms.

In October 2014, the final regulations under Section 316(b) of the CWA became effective; these regulations govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold. The rule establishes a national standard for impingement based on seven compliance options but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two million gallons per day ("MGD"), with a heightened entrainment analysis for those facilities over 125 MGD.

The Company currently has seven facilities that are subject to the final Section 316(b) regulations. Additionally, the Company may have one hydroelectric power facility subject to the final regulations. The Company anticipates that it may have to install impingement control technologies at certain of these stations that have once-through cooling systems. The Company is currently evaluating the need or potential for entrainment controls under the final rule; decisions will be made on a case-by-case basis after a thorough review of detailed biological, technology, cost, and benefit studies.

<u>Effluent Limitation Guidelines</u>

In September 2015, the EPA revised its effluent limitations guidelines ("ELG") for the steam electric power generating category. The final rule established updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required to (i) convert from wet to dry or closed cycle coal ash management, (ii) improve existing wastewater treatment systems, and/or (iii) install new wastewater treatment technologies in order to meet the new discharge limits. In April 2017, the EPA granted two separate petitions for reconsideration of the ELG rule and stayed future compliance dates in the rule. In September 2017, the EPA signed a rule to postpone the earliest compliance dates for certain waste streams regulations in the ELG rule from November 2018 to November 2020. However, the latest date for compliance with the regulation remained December 2023.

In October 2020, the EPA published a revised ELG rule that included changes in the requirements for two waste streams, flue gas desulphurization ("FGD") and bottom ash transport waters ("BATW"). The 2020 ELG rule also extended the compliance deadlines for final compliance with these requirements to December 2025 and offered an extended compliance deadline of December

2028 for facilities choosing to meet restrictive discharge limits or electing to cease coal combustion by that date.

On July 26, 2021, the EPA announced that it was initiating a rulemaking process to determine whether to adopt more stringent limitations than those in the 2020 ELG rules for steam electric generating units. 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.

Appendix 5A: Environmental Regulations Table 1

	Constituent	Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
AIR	Hg/HAPS	Mercury & Air Toxics Standards ("MATS")	12/16/2011	4/16/2017	Coal & Oil	All affected units compliant,
	Hg/HAPs	Mercury & Air Toxics Standards Risk and Technology Review (1)	5/7/2024	7/8/2027 7/8/28 w/ext.	Mt. Storm 1, 2, 3 Clover 1, 2 VCHEC 1, 2	PM limit was lowered from 0.030lb/MMBtu to 0.010lb/MMBtu. Eliminated option to demonstrate compliance through stack testing requiring the use of PM CEMS to demonstrate compliance with the limits.
	HAPs	NESHAPS for stationary combustion turbines (Subpart YYYY)	2/28/2022	2/2022	New / reconstructed CTs – major HAP loc. CERC	Gas-fired combined cycle and simple cycle combustion turbines constructed or reconstructed at major sources of HAP emissions after January 14, 2003 must meet the formaldehyde standard.
	SO_2	CSAPR (2)	2011	2015/2017	Fossil Units > 25 MWs	Allowances (In-Sys.; Trading)
		SO_2 NAAQS (75 ppb, 1-hr avg) (3)	6/2/2010	2018	Fossil Units > 25 MWs	EPA revised the primary SO2 NAAQs to 75 ppb. All units in compliance. Maintain current % sulfur levels.
	NOx	2020 Ozone Standard (70 ppb)	12/2020	TBD	Fossil Units > 25 MWs	EPA reconsidering the December 2020 final rule that retained the 2015 (70 ppb) NAAQS. CASAC members recommended a range of 55 to 60 ppb. EPA will evaluate information received and release further information in the future.
		2015 Ozone Standard (70 ppb) (4) "Ozone FIP, Group 3"	8/2023	Exp. Q3 2023	All Fossil Units > 25 MWs in VA	EPA released a final rule referred to as federal implementation plan ("FIP") on 8/4/2023 addressing interstate transport for the 2015 Ozone NAAQS. The FIP is intended to resolve the good neighbor obligations with respect to the 2015 NAAQs. Virginia and West Virginia are covered in the FIP. EPA uses a combination of approaches in the FIP including a revised CSAPR ozone season NOx emissions trading program with additional restrictions not included in any of the current CSAPR trading programs. Coal-fired electric generating units (excluding circulating fluidized bed (CFB) boilers) are subject to daily emission rate limits during ozone season and would have to surrender additional allowances (at a 3:1 ratio) if limits are exceeded after the first 50 tons.
		2015 Ozone Standard (70 ppb) "Ozone FIP Expanded Group 2"	2022	2022	Mt. Storm 1, 2, 3	Allowances (In-Sys.; Trading). Focuses on attainment with 2015 ozone standards. All units in compliance. States that have stayed the 2023 Ozone FIP rule must comply with Expanded Group 2.
		CSAPR Update Rule for 2008 NAAQs - Group 3 (5)	4/30/2021	5/1/2021	All Fossil Units	Allowances (In-Sys.; Trading). Focuses on attainment with 2008 ozone standards. All units in compliance.
	$PM_{2.5}$	2012 PM 2.5 NAAQs (6)	3/6/2024	Varies, depending on if existing or new	All new and existing Fossil Units	On March 6, 2024, the EPA released a final rule lowering the primary (health-based) NAAQS for particulate matter (PM NAAQS) to 9 micrograms per cubic meter down from 12.0 (ug/m3). The final rule retains the other PM standards at their current levels, including the 24-hour PM 2.5 NAAQs as well as the secondary standards for both PM2.5 and PM10 — 35 µg/m3 and 150 µg/m3, respectively. Litigation challenging this rule has been filed . The 2021-2023 monitoring data indicates that all areas in Virginia are currently in attainment with the new PM2.5 standards. Applicable permitting, (such as the construction of new electric generating units), may require NAAQS air quality modeling demonstrations. Where the new generating source is to be constructed would determine how much margin is available to maintain compliance with the NAAQs standards. There could be difficulties in the PM2.5 NAAQS air quality modeling demonstrations that will need to be conducted that could result in having to relocate a potential project or could include strategies such as installation of additional ambient monitors to indicate compliance with lower NAAQs standards. Areas not in attainment with a new lowered PM2.5 NAAQS will be designated nonattainment, which will trigger Nonattainment New Source Review ("NNSR") permitting requirements which contain more stringent Lowest Achievable Emissions Rate ("LAER") requirements and involve purchasing costly PM2.5 emission reduction credits ("ERCs"). For existing sources, if an area is designated as non-attainment, states are required to develop attainment plans to submit to EPA for approval to bring an area back in to attainment.
	CO_2	NSR Permitting for GHGs	5/2010	2011	New/Modified Fossil Units	GHG BACT (On EPA's unified agenda to revise).
		Emission Guidelines for GHG Emissions from Existing coal and natural gas/oil fired steam generating units (Section 111(d) Subpart UUUU(a)) (1)	5/9/2024	Starts in 2030, otherwise varies: depending on unit retirements	Mt. Storm 1, 2, 3 Clover 1, 2 VCHEC 1, 2	- If a unit commits to shutdown by 1/1/2032, exempt from regulation. - If a unit plans to operate 1/1/2032 – 1/1/2039, the unit must employ natural gas co-firing by 1/1/2030. - If a unit elects to convert to natural gas only, it must cease coal operations by 1/1/2030. - If a unit elects to operate on or after 1/1/2039, CCS with a 90% capture rate must be employed by 1/120/32. *** States have oversight on this rule and can propose options such as trading and averaging in their state plans, however those options must be achievable at equivalent stringencies for each source. States may also apply less stringent standards based on a planned unit retirement***

Constituent		Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
		EGU NSPS (Modified and Reconstructed) (Subpart TTTTa) (Section 111(b)) GHG emissions from new EGUs: Low and intermediate Load (1)	5/9/2024	Varies	New, Modified & Reconstructed Fossil Units, CERC	Will need to evaluate on a project-by-project basis. - Low load units < 20% capacity 120 – 160 lb CO2/MMBtu upon startup - Intermediate load units 20% - 40% capacity – 1,170 – 1560 lb CO2/MWh upon startup - Baseload > 40% Capacity 800-900 lb CO2/MWh upon startup and 90% CCS (with 100-150 lb CO2/MWh) starting in 2032
		Emission Guidelines for GHG Emissions from Existing natural gas fired combustion turbines Section 111(d)	TBD	TBD	All gas- and oil-fired combustion turbines	TBD, Expect: Best System Emission Reduction, source specific CO2 emission limit upon startup. EPA is expecting to come out with a proposal to regulate CO2 emissions from existing gas CTs in the future.
		Virginia CO_2 Budget Trading Rule (RGGI) (7)(8)	---	---	Existing and New Fossil Units ≥ 25 MW; Biomass units exempt; Biomass emissions from units that co-fire with biomass.	VA exited RGGI on 12/31/2023. SELC submitted petition against RGGI repeal. Ongoing litigation.
		Social Cost of Carbon	1/2021	2/2022	All new/existing units	Interim Social Cost of Greenhouse Gases in effect for Federal Agencies. There have been attempts to increase the social cost of carbon (and social cost of GHGs), but a federal regulation has not been developed yet. VCEA requires 2016 social cost of CO2 to be used ($51/ton).
		Federal CO_2 Program (Alternative Federal Legislation)	Uncertain	2026	Existing Fossil Units	Expected Price for CO_2
		The Commonwealth Clean Energy Policy (guidance document only)	7/1/2020	2020 – 2045	Existing and New Fossil Units, renewables	Sets a goal for Virginia to reach net zero emissions by 2045 and additionally states that by 2040 Virginia will have a net zero carbon energy economy. Developing energy resources necessary to produce 30% of Virginia's electricity from renewable energy sources by 2030 and 100% from Virginia's electricity carbon-free sources by 2040.
		VA Energy Plan (guidance document only)	10/2022	2022 – 2026	Existing and New fossil units, renewables	Encourages investments in hydrogen, carbon capture, and SMRs. VCEA to be evaluated based on the latest technology in 2023 and every five years thereafter. Restoring discretion to the SCC concerning plant retirement timelines and authority to defer RPS requirements. May expect to see updates to plan by DOE in Q1 2025.
		Federal and state vehicle emission standards	12/1/2021	2023-beyond	Existing and new Fossil Units	Federal and state rules regulating ghg emissions and LEV, ZEV standards. "Electrification" could indirectly impact unit operations.
		Virginia Clean Economy Act ("VCEA") (9)	7/1/2020	2020 – 2045	Existing and New Fossil Units	VCEA establishes a mandatory renewable portfolio standard in Virginia. There are mandates for significant developments of renewable energy and energy storage resources, as well as retirement of existing carbon-emitting resources. And shutting down all remaining fossil generating units by 2045. Allows petition for relief from these provisions if electric reliability or security is at risk.
		North Carolina – Clean Energy Plan	Uncertain	Uncertain	RM	North Carolina's Clean Energy Plan sets an electric power sector goal of 70% GHG reduction by 2030 (using a 2005 baseline), and a carbon neutrality goal by 2050. The plan fosters long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes and accelerates clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.
		West Virginia – Senate Bill 793	7/2020	7/2025	MS	Provides relief from B and O taxes if station stays operational until 2025. Required to pay back if facility is shut down. Can receive benefit beyond 2025, until plant is closed or bill is appealed or amended.
WASTE	ASH	CCR	4/17/2015	2020+	CEC landfill & bottom ash pond	Close landfill, bottom ash pond, and original pond due to station closure. Pond and landfill to be excavated and recycled off site.
				2020+	BR North, East, and West Ash Ponds	Close all three coal ash ponds by excavating material. East Pond and West Pond material has been excavated and consolidated in North Pond. Plan is to construct new landfill on property adjacent to North Pond, close North Pond by removal of CCR material, and place CCR material into new landfill, and close new landfill. (11)
				2020+	PP A/B/C, D, and E Ponds	All five ponds to be closed. Ponds A/B/C and E have been excavated of CCR and material consolidated in Pond D. Plan is to construct new landfill adjacent to Pond D. Continuing to evaluate onsite and offsite disposal options or offsite recycling. (11)
				2020+	CH 3, 4, 5 & 6, Lower and Upper Ponds	Lower and Upper Ponds Closure through excavation of CCR material and hauling to onsite or offsite landfill for disposal or offsite for recycling. (11)
				2020	YT 1, 2	Landfill closure (due to coal unit retirements). Closure completed 9/2020.
				10/2018	CL 2 FGD Ponds	Pond retrofit in compliance with CCR Rule and placed back into service.
				10/2018	MS Finger and Pyrite Ponds	Pond closure, retrofit, and/or rebuilding. Three of five original ponds placed back into service in compliance with CCR Rule.

	Constituent	Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
				TBD	BR, CEC, CH, CL, MS, PP, VCHEC, YT	Monitor groundwater and corrective actions, if needed.
		2024 CCR Legacy Rule (1)	5/8/2024	11/2024	AV, BR, CEC, CH, CL, HOPE, MECK, MS, PP, SH, VCHEC, YT	Facility Evaluation report due February 2026 and 2027; based on results of report, if additional ash locations are identified, will require groundwater monitoring installation and testing and formal closure of ash area. The requirements of the legacy rule are required regardless of current or future operating status of the units.
WATER	Water 316(b)	316(b) Impingement & Entrainment (10)(15)	5/19/2014	2016 (12)	BG	316(b) Studies to Determine Compliance Needs and Submit Design & Source Water Body Data.
				2019 (12)(13)	NA, AV	
				2020 (12)	SU, PP	
				2021	CH	
				2022 (7)	YT3	
				2022	CL	
				2028 (12)(14)	NA	VSDs; Screens; Fish Returns NA: Permit received in April 2024. Existing structure BTA. No additional studies or changes were required. Will need to submit updated 122.21(r) information with the next reissuance or demonstrate that there have not been any changes to the intake system.
				2028 (12)(14)	SU	SU: No change. Still waiting for the draft permit. The current permit has been administratively continued.
				2023,2028 (12)(14)	CH,7,8 (16)	CH: No change. Still waiting for the draft permit. The current permit has been administratively continued.
	316(a)	Thermal discharge biological effects	5/15/2000	NA	CH, SU	Surry's (SU) Rule 316(a) demonstration update report submitted 8/25/2020. Chesterfield's (CH) 316(a) demonstration update report submitted 12/29/2020. Fish Protection Pilot Study conducted in 2021 may help mitigate future required measures at Chesterfield. Decision to reissue 316(a) variance at both Chesterfield and Surry will be made by DEQ during next permit reissuance process expected 2024-2025.
				NA	MS	Rule 316(a) variance pursued since 2007, under an Administrative Order. Litigation initiated in 2021 by Sierra Club and Potomac Riverkeeper. Last Administrative Order has a requirement to meet either the 5-degree delta or the requirements for the 316(a) variance by 10/31/22 which was achieved, and the Administrative Order is closed. Air-cooled chillers have been rented and installed to meet the 5-degree delta requirement for the first two years. The Company is currently installing permanent chillers at the site
	Water ELG	Effluent Limit Guidelines	9/30/2015	3/31/2024 (17)	MS	Bottom Ash - Closed Loop Wet System, system complete 2023. No further actions.
	Water ELG Supplemental Rule	Effluent Limit Guidelines (1)	5/9/2024	7/8/2024	MS Phase A landfill, CL Stage 3 landfill, VCHEC	Will require zero liquid discharge ("ZLD") on landfill leachate while coal units are operating. Once units close, discharges will be subject to arsenic and mercury limits (similar to DEQ requirements). If units opt to declare by 12/31/25 through a Notice of Planned Participation ("NOPP") that they will cease burning coal by 12/31/34, they do not require ZLD during the operating life of the units and are only subject to the arsenic and mercury limits post closure. The limits become effective once incorporated into a VPDES permit, but not later than 12/31/2029.
					CH, PP, CEC, BR	Non-coal units can file a NOPP by 12/31/2025 for the cease burning coal by 2034 subcategory to be exempted from ZLD for Combustion Residual Leachate ("CRL"). The CRL will be subject to arsenic and mercury limits similar to what is currently required by DEQ. The limits become effective once incorporated into a VPDES permit, but not later than 12/31/2029.

Constituent		Key Regulation	Final Rule	Compliance Date	Affected Units or Plants	Baseline Means of Compliance
WILDLIFE	Threatened & Endangered	Atlantic Sturgeon Endangered Species Listing	2/6/2012	2027 (18)	CH 7, 8	ncidental Take Permit ("ITP") issued December 2020 with 5-year permit term. ITP permit modification is in process to reflect new findings. Final modification timeline is unknown. A successful modification of the ITP will reduce the Company's operational constraints associated with risk of take. Retirement of CH 5 and 6 will reduce the Company's estimated incidental take to some extent, but unit 6 will still need coverage for ongoing water withdrawals. Best Technology Available ("BTA") for protection of Atlantic Sturgeon to be determined by DEQ as part of 316(b) and 316(a) processes during next permit reissuance. Has been administratively continued from its expected 2022-2023 timeframe.
		Atlantic Sturgeon Critical Habitat Designation	2017		CH 7, 8	Thermal discharge 316(a) studies completed during 2020 at CH and SU to determine compliance needs during NPDES permit reissuance. Results of studies will be considered in BTA determinations by DEQ under 316(b) and 316(a) during next permit reissuance process.
					PP, SU, CH 7, 8	Atlantic Sturgeon Critical Habitat Designation (CHD) may be a consideration for PP, SU and CH permits.
		Bald and Golden Eagle Act	2024	2027	Distribution; lesser impacts on Transmission	ITP will require proactive replacement of distribution poles within Avian Protection Areas over the course of 50 years starting in 2027. Reactive retrofits will also be required along with time of year restrictions and project planning adjustments in Avian Protection Areas. No decision has been made yet on whether to file for the ITP.
		Northern Long Eared and Tri-Colored Bats	2023/2024		New Solar and Transmission, Potentially Transmission O & M; Tri Colored could impact plants with ACCs (WC, GRV, possibly VCHEC, BR)	Both listings will affect project planning, routing, and scheduling for time of year restrictions but not a direct cost estimate. Associated compliance measures (mitigation, seasonal or temporal operations modification, time of year restrictions). Power stations with Air Cooling Condensers may be affected. As of 10/9/2024, EPA has not yet made a listing determination for the Tri-Colored Bat.

Notes: Compliance assumed January 1 unless otherwise noted.

1) Challenges to the rule have been submitted on behalf of several states (VA and WV included), industry coalitions, and other entities.
2) System is expected to have sufficient SO2 allowances.
3) SO_2 NAAQS modeling submitted to VDEQ in November 2016. Modeling shows compliance with the NAAQS. EPA has approved and issued notice indicating NAAQS attainment in August 2017. In March 2019, EPA published final rule retaining 75 ppb 1-hr SO_2 NAAQS. On March 28, 2024, Environmental Groups filed a complaint against EPA and DC circuit arguing that EPA violated the CAA by failing to ensure SIPs are in place to meet the NAAQs for SO_2. No additional impacts expected.
4) On June 27, 2024, the U.S. Supreme Court, issued a stay of the Final FIP. In August 2024, the EPA released a policy memo indicating that they intend to issue an interim rule that will likely mimic the previous iteration of this rule ("Revised CSAPR Update Rule").
5) Final rule required EPA to issue FIPs with revised tighter NOx allowance budgets via a Group 3 Trading program. EPA approved SIP revision to designate N. VA to attainment and include maintenance plan through 2030.
6) Challenges to the rule have been submitted on behalf of several states (WV included), industry associations led by the U.S. Chamber, and other entities.
7) Cost of allowances can be recovered by Phase I and Phase II utilities from ratepayers.
8) On January 15, 2024, Governor Youngkin signed EO 9, which orders DEQ to start the withdraw from RGGI.
9) VCEA includes a provision to adopt regulations no earlier than July 1, 2024, to reduce CO_2 using a multistate trading program for the period of 2031 to 2050.
10) Agency determined the 316(b) Rule does not apply to Mt. Storm under the assumption that the plant's man-made lake does not qualify as a "water of the U.S."
11) As a result of the SB 1355 legislation (Virginia Code § 10.1-1402.03), ash in ponds must be excavated and disposed of in the landfill or taken off site for recycling. Exact timing of start of work at each site TBD.
12) 316(b) studies and reports completed and submitted to agency. Permits administratively continued and waiting for BTA determination.
13) 316(b) information for NA submitted and under consideration by DEQ.
14) Assumes permit issued with a 4-year compliance schedule. Projected permit issuance dates: NA - January 2024, SU - March 2024, CH - September 2024.
15) All known 316(b) studies have been submitted. Technology determinations pending from DEQ in next permit renewals.
16) Having the units shutdown prior to the ELG-driven deadline of December 31, 2023, relieves DE of any further 316(b) compliance requirements for Units 5 & 6. Compliance is satisfied by shutting the units down since they are no longer withdrawing cooling water, and therefore 316(b) requirements will not apply.
17) March 31, 2024 is the applicability deadline that was submitted to DEP for approval in October 2021.
18) Compliance dates are determined during NPDES permit reissuance process and are expected to be the same as those shown for 316(b) compliance.

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. When setting capacity factor limits for new incremental CT units, the Company assumed gas availability in the spring, summer, and fall, with oil-only operations in the winter when gas is most constrained.

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 2024 IRP 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 2024 IRP, 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 held constant through 2027, 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 may 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 meet their corporate 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 11 million in 2025 to approximately 45 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 2024 IRP includes a forecast of Virginia REC price, which are projected to be equal to or higher than 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 2024 IRP 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 29, 2024, 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 and Federal CO_2 prices are provided by ICF for all years forecasted within this 2024 IRP. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM base residual auction through the 2025/2026 delivery year, then transitioning to the ICF capacity forecast.

In the 2024 IRP, the Company utilized six commodity forecasts:

- Base Case with EPA 111 Rules
- High Fuel Price with EPA 111 Rules

- Low Fuel Price with EPA 111 Rules
- Base Case without EPA 111 Rules
- High Fuel Price without EPA 111 Rules
- Low Fuel Price without EPA 111 Rules

The Company used the Base Case commodity forecast for the Portfolios. The remaining four 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 2024 IRP. 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 2024 IRP 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 IRA are incorporated, and enactment of various RPS policies occur, including the VCEA.

Table 1 below provides a comparison of the four commodity price forecasts in this 2024 IRP with the base commodity forecast used in the 2023 Update.

Table 1: Fuel, Power, and REC Price Commodity Forecast Comparison

	2023-2038 Average Value (Nominal $)	2024-2039 Average Value (Nominal $)					
Fuel Price	2023 Base Case	Base Case w/EPA Rules	High Fuel Price w/EPA Rules Case	Low Fuel Price w/ EPA Rules Case	Base Case w/o EPA Rules	High Fuel Price w/o EPA Rules	Low Fuel Price w/o EPA Rules
Henry Hub Natural Gas ($/MMbtu)	4.15	4.67	6.63	3.38	4.39	6.32	3.19
Zone 5 Delivered Natural Gas ($/MMbtu)	3.89	4.88	6.83	3.58	4.60	6.53	3.19
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	79.63	81.90	82.11	81.82	81.97	82.40	81.84
No. 2 Oil ($/MMbtu)	19.88	20.29	22.37	18.65	20.29	22.37	18.65
Electric and REC Prices							
PJM-DOM On-Peak ($/MWh)	45.23	37.76	48.01	33.26	34.11	44.17	35.03
PJM-DOM Off-Peak ($/MWh)	40.56	38.87	50.30	33.48	35.96	48.08	36.53
PJM Tier 1 REC Prices ($/MWh)	16.67	35.59	30.52	37.77	37.15	33.97	39.41
VA REC Prices[1] ($/MWh)	17.61	36.01	30.93	38.52	37.57	34.39	40.16
RTO Capacity Prices ($/kW-yr)	56.09	135.56	132.55	137.58	98.88	99.50	100.09

Note: (1) Reflects ICF forecast data for only rather than a market blend.

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.

Appendix 5B-1: VCEA with EPA 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 ($/ton)	No. 2 Oil ($/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)
2024	2.86	3.29	71.57	17.86	57.80	40.71	36.00	10.56	28.92	10.56	28.92	2.40	1,250.00	3.50	0.00
2025	3.48	4.07	72.99	17.72	62.22	45.99	35.51	61.87	169.50	98.99	271.20	2.46	1,279.42	3.58	0.00
2026	3.65	4.14	73.85	17.48	55.21	43.85	36.66	71.06	194.68	122.52	335.68	2.78	1,514.44	3.48	0.00
2027	3.60	3.83	74.40	18.18	39.13	36.87	44.20	64.07	175.53	105.93	290.22	3.21	1,494.91	3.29	0.00
2028	3.79	3.91	75.67	19.00	34.92	36.41	44.87	86.22	236.23	125.15	342.88	3.32	1,095.19	3.32	0.00
2029	4.03	4.15	77.18	19.37	33.35	37.77	44.82	109.25	299.31	144.65	396.31	3.39	801.22	3.39	0.00
2030	4.27	4.41	78.57	19.74	31.78	39.05	44.76	133.10	364.67	164.99	452.02	3.45	345.10	3.45	0.00
2031	4.66	4.79	80.19	20.11	30.84	37.24	41.74	147.93	405.27	185.61	508.53	3.52	293.08	3.52	0.00
2032	5.06	5.19	81.83	20.48	29.93	35.44	38.64	155.99	427.37	200.57	549.51	2.39	226.88	2.39	0.00
2033	5.13	5.25	83.56	20.86	30.06	34.98	35.53	163.99	449.29	211.36	579.06	2.43	145.96	2.43	0.00
2034	5.19	5.33	85.36	21.24	30.16	34.55	32.40	171.99	471.21	222.14	608.60	2.48	74.36	2.48	0.00
2035	5.26	5.39	87.19	21.65	30.18	34.19	29.25	180.04	493.25	232.99	638.32	2.53	2.53	2.53	0.00
2036	5.53	5.66	89.05	22.08	31.95	37.07	28.10	188.76	517.16	243.91	668.25	2.58	2.58	2.58	0.00
2037	5.80	5.93	90.99	22.52	33.76	39.86	26.90	198.16	542.91	254.89	698.32	2.63	2.63	2.63	0.00
2038	6.08	6.21	92.98	22.98	35.54	42.62	25.65	207.93	569.67	265.92	728.54	2.68	2.68	2.68	0.00
2039	6.38	6.50	95.06	23.45	37.35	45.31	24.39	218.07	597.46	277.01	758.94	2.74	2.74	2.74	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	**VCEA with EPA Commodity Forecast**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2024	2.86	2.86	2.86
2025	3.48	3.49	3.48
2026	3.65	4.56	3.46
2027	3.60	5.65	3.00
2028	3.79	5.86	2.96
2029	4.03	5.98	3.02
2030	4.27	6.09	3.08
2031	4.66	6.57	3.17
2032	5.06	7.07	3.27
2033	5.13	7.39	3.37
2034	5.19	7.72	3.48
2035	5.26	8.07	3.59
2036	5.53	8.30	3.68
2037	5.80	8.55	3.78
2038	6.08	8.80	3.88
2039	6.38	9.06	3.98

Appendix 5B-3: Commodity Price Forecast, Natural Gas

	Zone 5 Delivered Natural Gas ($/MMBtu)		
Year	**VCEA with EPA Commodity Forecast**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2024	3.29	3.29	3.29
2025	4.07	4.08	4.07
2026	4.14	5.05	3.95
2027	3.83	5.87	3.22
2028	3.91	5.99	3.09
2029	4.15	6.10	3.14
2030	4.41	6.23	3.21
2031	4.79	6.70	3.30
2032	5.19	7.20	3.40
2033	5.25	7.52	3.50
2034	5.33	7.85	3.61
2035	5.39	8.20	3.72
2036	5.66	8.43	3.81
2037	5.93	8.67	3.90
2038	6.21	8.93	4.00
2039	6.50	9.18	4.10

Appendix 5B-4: Commodity Price Forecast, Coal (FOB)

	CAPP CSX: 12,500 1%S FOB ($/ton)		
Year	**VCEA with EPA Commodity Forecast**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2024	71.57	71.57	71.57
2025	72.99	73.00	72.99
2026	73.85	74.39	73.80
2027	74.40	75.41	74.21
2028	75.67	76.52	75.56
2029	77.18	77.62	77.07
2030	78.57	78.73	78.48
2031	80.19	80.31	80.16
2032	81.83	81.92	81.83
2033	83.56	83.59	83.53
2034	85.36	85.39	85.27
2035	87.19	87.28	87.06
2036	89.05	89.05	88.93
2037	90.99	90.99	90.85
2038	92.98	92.98	92.85
2039	95.06	95.06	94.92

Appendix 5B-5: Commodity Price Forecast, Oil

	No. 2 Oil ($/MMBtu)		
Year	**VCEA with EPA Commodity Forecast**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2024	17.86	17.86	17.86
2025	17.72	17.72	17.72
2026	17.48	17.97	16.96
2027	18.18	19.49	16.64
2028	19.00	20.67	17.13
2029	19.37	21.18	17.39
2030	19.74	21.68	17.64
2031	20.11	22.21	18.10
2032	20.48	22.82	18.43
2033	20.86	23.46	18.81
2034	21.24	24.02	19.18
2035	21.65	24.43	19.63
2036	22.08	25.04	19.96
2037	22.52	25.92	20.63
2038	22.98	26.46	20.97
2039	23.45	26.94	21.41

Appendix 5B-6: Commodity Price Forecast, On-Peak Power Price

	PJM-DOM On-Peak ($/MWh)		
Year	VCEA with EPA Commodity Forecast	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2024	57.80	57.80	57.80
2025	62.22	62.30	62.22
2026	55.21	62.26	54.23
2027	39.13	55.63	38.60
2028	34.92	50.60	34.11
2029	33.35	46.13	31.02
2030	31.78	40.77	26.95
2031	30.84	42.32	26.71
2032	29.93	43.20	25.76
2033	30.06	42.94	24.98
2034	30.16	42.38	23.95
2035	30.18	41.77	22.94
2036	31.95	42.90	23.88
2037	33.76	44.31	25.17
2038	35.54	45.72	26.36
2039	37.35	47.13	27.55

Appendix 5B-7: Commodity Price Forecast, Off-Peak Power Price

	PJM-DOM Off-Peak ($/MWh)		
Year	VCEA with EPA Commodity Forecast	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2024	40.71	40.71	40.71
2025	45.99	46.05	45.99
2026	43.85	49.73	42.96
2027	36.87	51.56	35.96
2028	36.41	51.74	35.00
2029	37.77	51.50	34.49
2030	39.05	50.44	32.98
2031	37.24	51.69	32.32
2032	35.44	51.99	30.76
2033	34.98	50.73	29.32
2034	34.55	49.05	27.56
2035	34.19	47.26	25.82
2036	37.07	49.34	27.45
2037	39.86	51.80	29.50
2038	42.62	54.32	31.47
2039	45.31	56.87	33.45

Appendix 5B-8: Commodity Price Forecast, PJM Tier 1 RECs

	PJM Tier 1 REC Prices ($/MWh)		
Year	VCEA with EPA Commodity Forecast	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2024	36.00	36.00	36.00
2025	35.51	35.51	35.51
2026	36.66	36.66	38.63
2027	44.20	42.38	44.20
2028	44.87	41.88	44.87
2029	44.82	39.18	44.82
2030	44.76	37.52	44.76
2031	41.74	34.61	42.67
2032	38.64	31.57	40.55
2033	35.53	28.44	38.44
2034	32.40	25.22	36.31
2035	29.25	21.90	34.22
2036	28.10	20.92	32.90
2037	26.90	19.89	31.56
2038	25.65	18.85	30.15
2039	24.39	17.78	28.71

Note: The 2023 - 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	VCEA with EPA Commodity Forecast	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2024	36.01	36.01	36.01
2025	38.15	38.15	38.15
2026	39.96	39.96	47.25
2027	44.91	42.95	44.91
2028	44.87	41.88	44.87
2029	44.82	39.18	44.82
2030	44.76	37.52	44.76
2031	41.74	34.61	42.67
2032	38.64	31.57	40.55
2033	35.53	28.44	38.44
2034	32.40	25.22	36.31
2035	29.25	21.90	34.22
2036	28.10	20.92	32.90
2037	26.90	19.89	31.56
2038	25.65	18.85	30.15
2039	24.39	17.78	28.71

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	VCEA with EPA Commodity Forecast	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2024	10.56	10.56	10.56
2025	61.87	61.87	61.87
2026	71.06	71.06	71.06
2027	64.07	64.07	64.07
2028	86.22	86.22	86.22
2029	109.25	109.25	109.25
2030	133.10	133.10	133.10
2031	147.93	147.93	147.93
2032	155.99	153.17	160.10
2033	163.99	155.98	167.15
2034	171.99	167.20	177.60
2035	180.04	175.77	185.10
2036	188.76	181.97	191.18
2037	198.16	191.17	201.31
2038	207.93	200.75	211.88
2039	218.07	210.70	222.89

Appendix 5B-11: Commodity Price Forecast, PJM RTO Capacity

	RTO Capacity Prices ($/MW-day)		
Year	VCEA with EPA Commodity Forecast	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2024	28.92	28.92	28.92
2025	169.50	169.50	169.50
2026	194.68	194.68	194.68
2027	175.53	175.53	175.53
2028	236.23	236.23	236.23
2029	299.31	299.31	299.31
2030	364.67	364.67	364.67
2031	405.27	405.27	405.27
2032	427.37	419.63	438.63
2033	449.29	427.35	457.94
2034	471.21	458.09	486.58
2035	493.25	481.57	507.13
2036	517.16	498.54	523.78
2037	542.91	523.76	551.54
2038	569.67	549.99	580.50
2039	597.46	577.26	610.67

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	VCEA with EPA Commodity Forecast	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2024	10.56	10.56	10.56
2025	98.99	98.99	98.99
2026	122.52	122.52	122.52
2027	105.93	105.93	105.93
2028	125.15	125.15	125.15
2029	144.65	144.65	144.65
2030	164.99	164.99	164.99
2031	185.61	185.61	185.61
2032	200.57	196.93	205.86
2033	211.36	201.03	215.42
2034	222.14	215.96	229.39
2035	232.99	227.47	239.54
2036	243.91	235.13	247.03
2037	254.89	245.89	258.94
2038	265.92	256.73	270.97
2039	277.01	267.64	283.13

Appendix 5B-13: Commodity Price Forecast, DOM Zone Capacity

	DOM Zone Capacity Prices ($/MW-day)		
Year	VCEA with EPA Commodity Forecast	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2024	28.92	28.92	28.92
2025	271.20	271.20	271.20
2026	335.68	335.68	335.68
2027	290.22	290.22	290.22
2028	342.88	342.88	342.88
2029	396.31	396.31	396.31
2030	452.02	452.02	452.02
2031	508.53	508.53	508.53
2032	549.51	539.54	563.99
2033	579.06	550.77	590.20
2034	608.60	591.67	628.47
2035	638.32	623.20	656.27
2036	668.25	644.19	676.81
2037	698.32	673.68	709.42
2038	728.54	703.37	742.38
2039	758.94	733.27	775.71

Note:

1) RTO capacity prices are restated in the units used by the PJM capacity market.

Appendix 5B-14: Commodity Price Forecast, SO_2 Emission Allowances

	SO_2 (\$/Ton)		
Year	**VCEA with EPA Commodity Forecast**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2024	2.40	2.40	2.40
2025	2.46	2.46	2.46
2026	2.78	2.78	2.78
2027	3.21	3.21	3.21
2028	3.32	3.32	3.32
2029	3.39	3.39	3.39
2030	3.45	3.45	3.45
2031	3.52	3.52	3.52
2032	2.39	2.39	2.39
2033	2.43	2.43	2.43
2034	2.48	2.48	2.48
2035	2.53	2.53	2.53
2036	2.58	2.58	2.58
2037	2.63	2.63	2.63
2038	2.68	2.68	2.68
2039	2.74	2.74	2.74

Note:

1) CSAPR SO_2 and nationwide SO_2 prices are used as the SO_2 market price.

Appendix 5B-15: Commodity Price Forecast, NOx Emission Allowances

	CSAPR Ozone NOx ($/Ton)		
Year	VCEA with EPA Commodity Forecast	High Fuel Price Case Commodity Forecast	Low Fuel Price Case Commodity Forecast
2024	1,250.00	1,250.00	1250.00
2025	1,279.42	1,279.42	1279.42
2026	1,514.44	6,275.05	1393.30
2027	1,494.91	9,353.55	797.08
2028	1,095.19	5,641.90	619.50
2029	801.22	1,658.86	440.11
2030	345.10	1,409.15	264.58
2031	293.08	1,148.89	211.02
2032	226.88	877.68	155.24
2033	145.96	596.01	97.31
2034	74.36	303.65	37.18
2035	2.53	2.53	2.53
2036	2.58	2.58	2.58
2037	2.63	2.63	2.63
2038	2.68	2.68	2.68
2039	2.74	2.74	2.74

Appendix 5B-16: Commodity Price Forecast, NOx Emission Allowances

	CSAPR Annual NOx ($/Ton)		
Year	**VCEA with EPA Commodity Forecast**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2024	3.50	3.50	3.50
2025	3.58	3.58	3.58
2026	3.48	3.48	3.48
2027	3.29	3.29	3.29
2028	3.32	3.32	3.32
2029	3.39	3.39	3.39
2030	3.45	3.45	3.45
2031	3.52	3.52	3.52
2032	2.39	2.39	2.39
2033	2.43	2.43	2.43
2034	2.48	2.48	2.48
2035	2.53	2.53	2.53
2036	2.58	2.58	2.58
2037	2.63	2.63	2.63
2038	2.68	2.68	2.68
2039	2.74	2.74	2.74

Appendix 5B-17: Commodity Price Forecast, CO_2

	Federal CO_2 ($/Ton)		
Year	**VCEA with EPA Commodity Forecast**	**High Fuel Price Case Commodity Forecast**	**Low Fuel Price Case Commodity Forecast**
2024	0.00	0.00	0.00
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 5B-18: Delivered Fuel Data (VCEA with EPA Specific)

Company Name: Virginia Electric and Power Company — **Schedule 18**

FUEL DATA

	(ACTUAL)			(PROJECTED)															
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
I. Delivered Fuel Price ($/mmBtu)(1)																			
a. Nuclear	0.58	0.58	0.64	0.59	0.58	0.61	0.60	0.60	0.60	0.61	0.63	0.67	0.78	0.81	0.88	0.91	0.94	0.98	1.01
b. Biomass	3.75	3.95	3.72	3.49	3.56	3.64	3.71	3.78	3.84	3.92	3.99	4.01	4.03	4.05	4.06	4.14	4.23	4.32	4.41
c. Coal	2.46	3.04	4.10	2.90	2.94	3.03	3.11	3.19	3.25	3.31	3.37	3.42	3.49	3.57	3.66	3.76	3.85	3.96	4.06
d. Heavy Fuel Oil	14.23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
e. Light Fuel Oil(2)	14.25	18.31	19.22	19.16	18.44	18.21	18.93	19.76	20.15	20.53	20.92	21.30	21.69	22.10	22.52	22.97	23.42	23.90	24.39
f. Natural Gas	4.04	7.15	3.67	3.61	4.35	4.42	4.11	4.19	4.43	4.69	5.08	5.48	5.55	5.62	5.70	5.98	6.28	6.59	6.90
II. Primary Fuel Expenses (cents/kWh)(3)																			
a. Nuclear	0.60	0.58	0.60	0.61	0.60	0.63	0.62	0.62	0.63	0.63	0.65	0.70	0.82	0.84	0.91	0.95	0.98	1.01	1.05
b. Biomass	2.74	3.68	6.05	4.02	4.07	4.16	4.22	4.30	4.37	4.45	4.52	4.47	4.50	4.65	4.65	4.75	4.85	4.95	5.06
c. Coal	5.38	2.69	4.42	2.96	3.00	3.08	3.16	3.24	3.30	5.43	6.28	6.13	6.99	6.72	6.87	6.89	7.02	7.61	8.02
d. Heavy Fuel Oil	15.81	5.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
e. Light Fuel Oil(2)	2.91	14.87	18.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
f. Natural Gas	5.61	7.30	2.72	2.12	2.68	2.66	2.67	2.79	2.93	3.11	3.47	3.76	3.87	3.91	3.96	4.16	4.36	4.58	4.83
g. PPA(4)	4.71	5.73	4.81	6.37	6.59	6.47	6.61	6.42	3.45	3.44	3.05	2.66	2.68	2.69	2.68	2.92	3.15	3.37	3.60
i. Economy Energy Purchases(5)	5.13	8.64	3.77	4.62	5.17	5.05	3.74	3.67	3.61	3.67	3.61	3.41	3.40	3.39	3.37	3.58	3.77	3.95	4.11
j. Capacity Purchases ($/kW-Year)	41.52	31.84	16.50	10.56	98.99	122.52	105.93	125.15	144.65	164.99	185.61	200.57	211.36	222.14	232.99	243.91	254.89	265.92	277.01

(1) Delivered fuel price for NAPP (12,900, 3.2% FOB), No. 2 Oil, No. 6 Oil and DOM Zone Delivered Natural Gas are used to represent Coal, Heavy Fuel, Light Fuel Oil, and Natural Gas respectively.

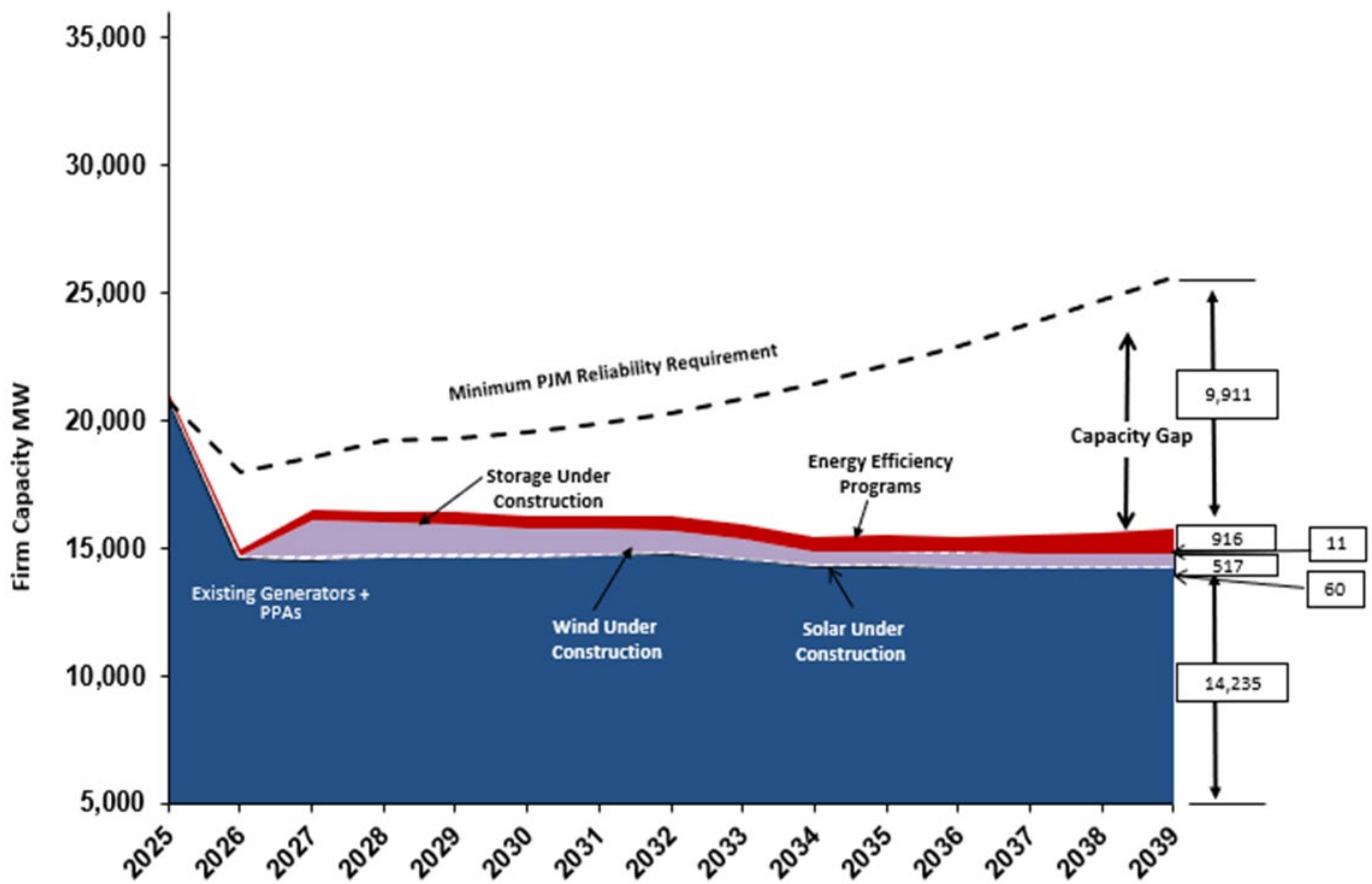
(2) Light fuel oil is used for reliability only at dual-fuel facilities.

(3) Primary Fuel Expenses for Nuclear, Biomass, Coal, and Natural Gas are based on North Anna 1, Altavista, Mount Storm 1, and Possum Point 6, respectively.

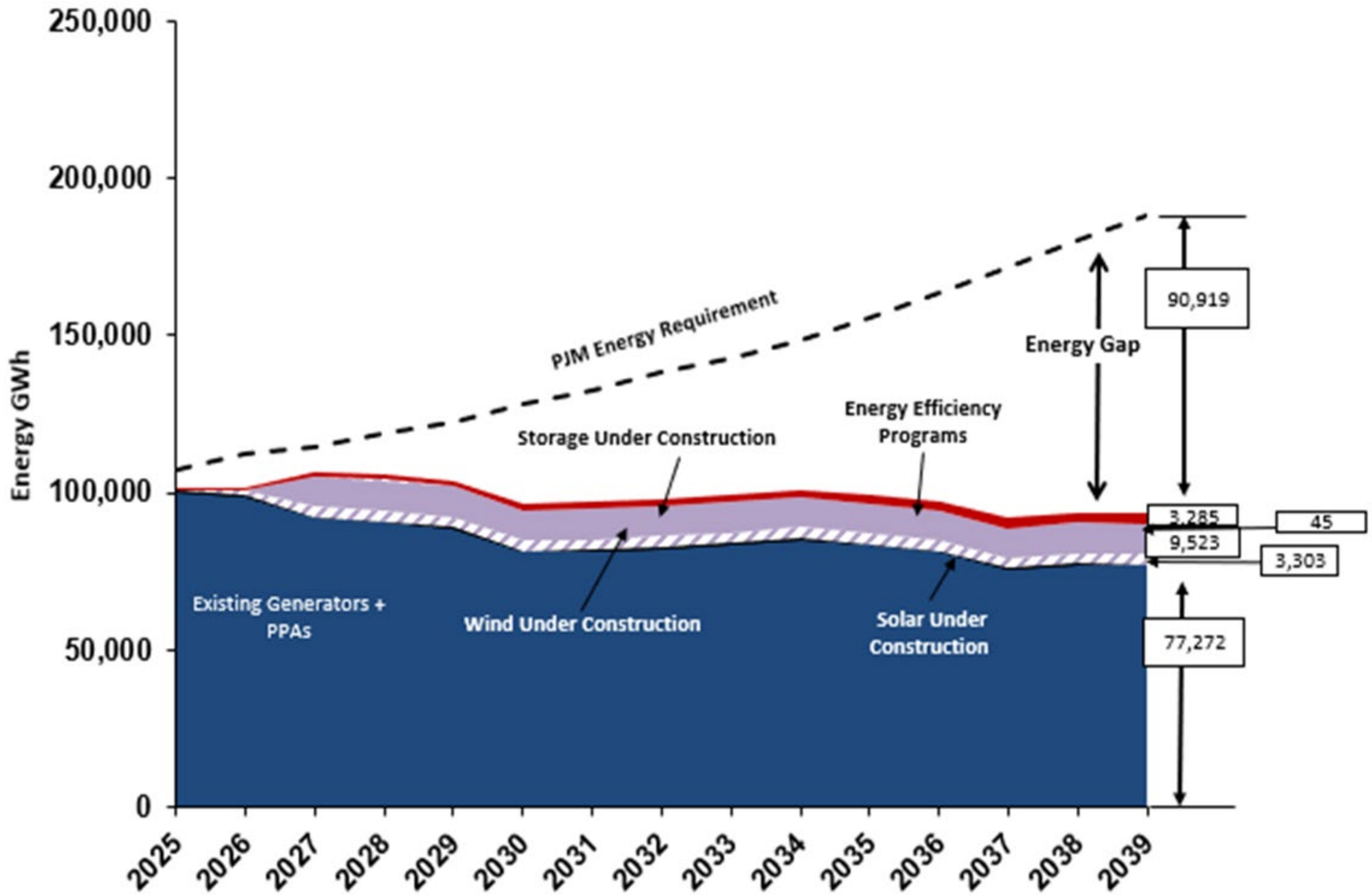
(4) Average of PPA fuel expenses.

(5) Average cost of market energy purchases.

Appendix 5C: REC RPS Only with EPA – Current Company Capacity Position (2025 to 2039)

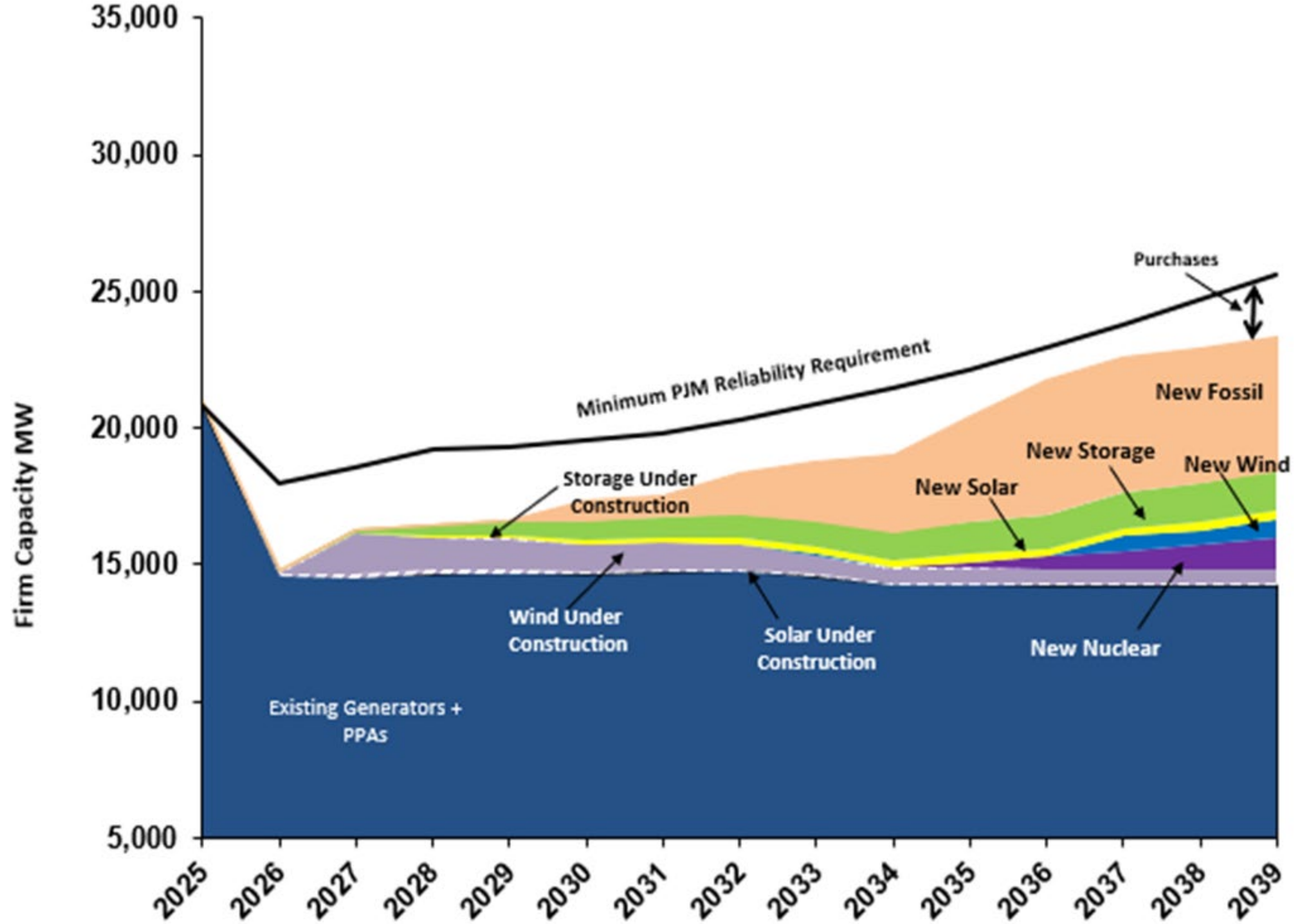


Appendix 5C: REC RPS Only with EPA – Current Company Energy Position (2025 to 2039)



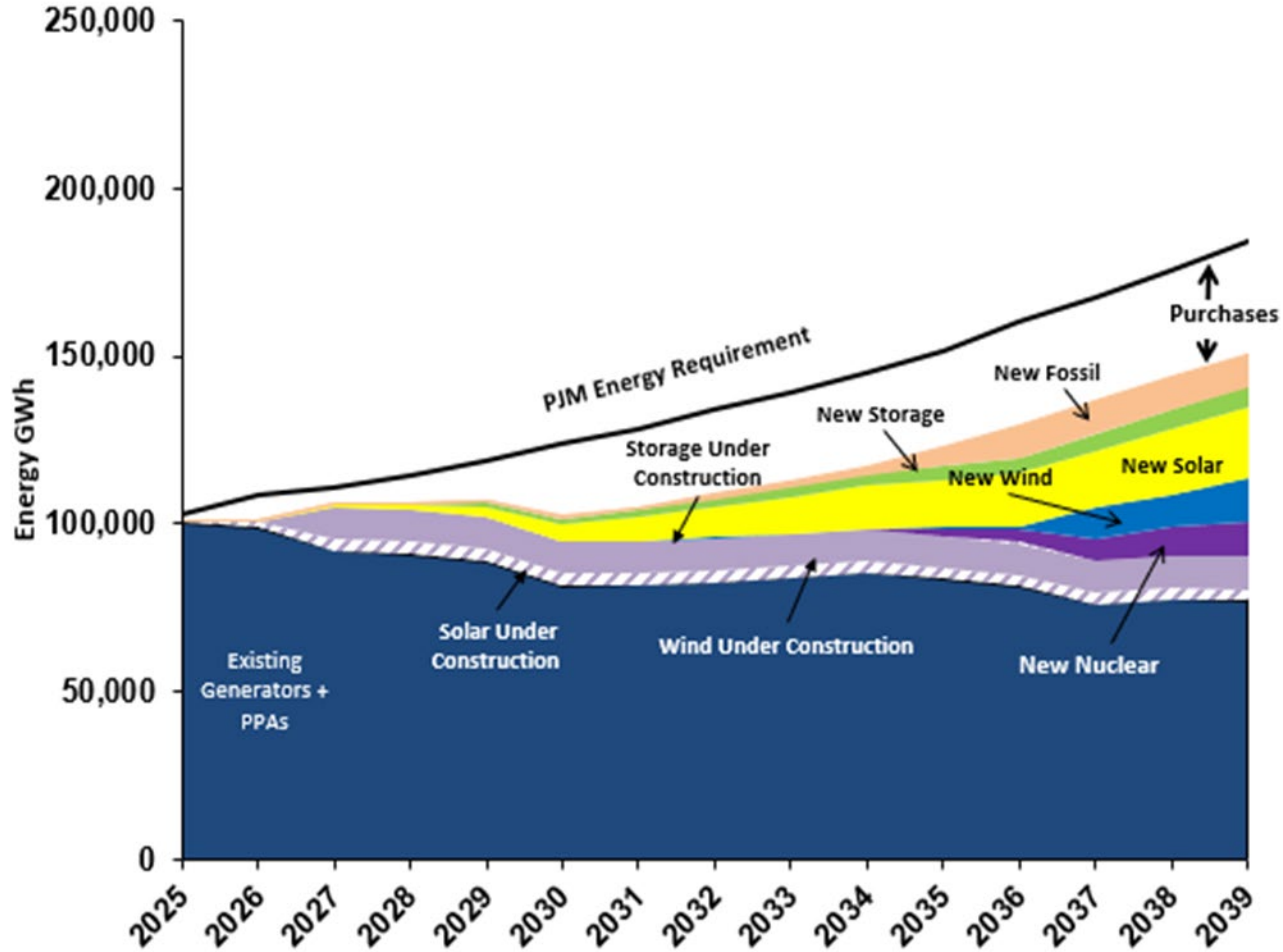
Appendix 5C: REC RPS Only with EPA – Summer Capacity, Energy, and RECs

Capacity (Net of DSM/EE)



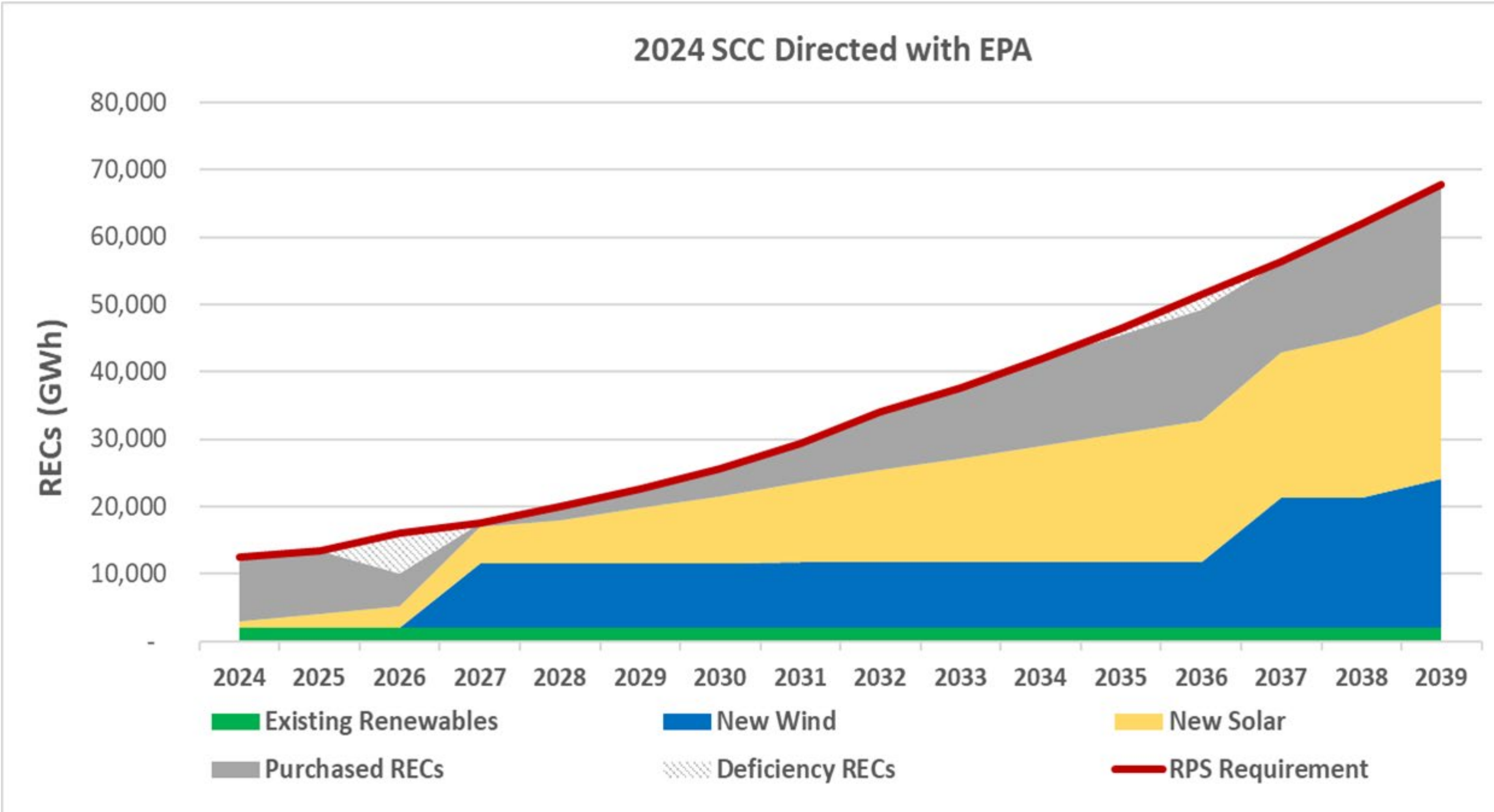
Appendix 5C: REC RPS Only with EPA – Summer Capacity, Energy, and RECs

Energy (Net of DSM/EE)

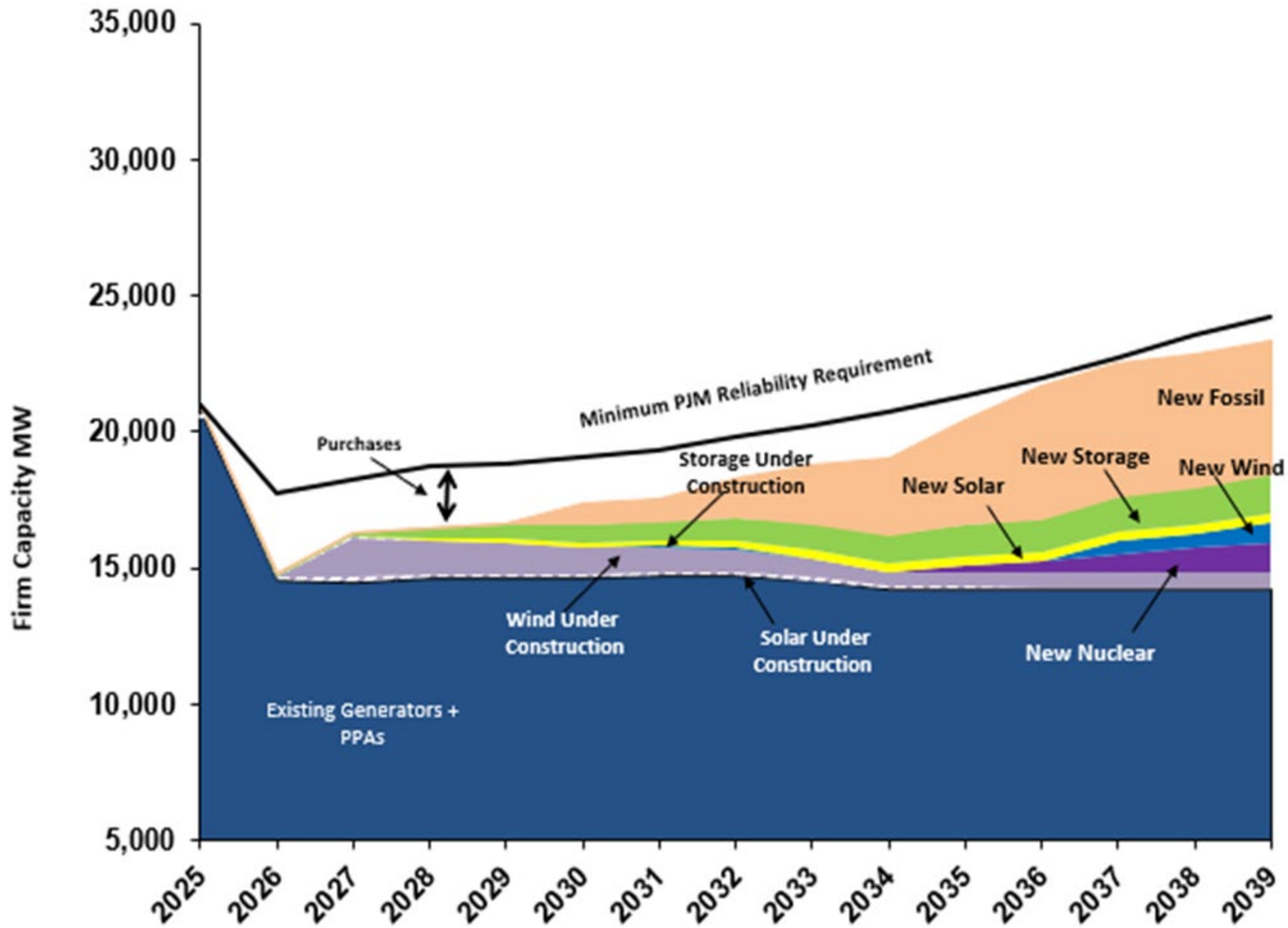


Appendix 5C: REC RPS Only with EPA – Summer Capacity, Energy, and RECs

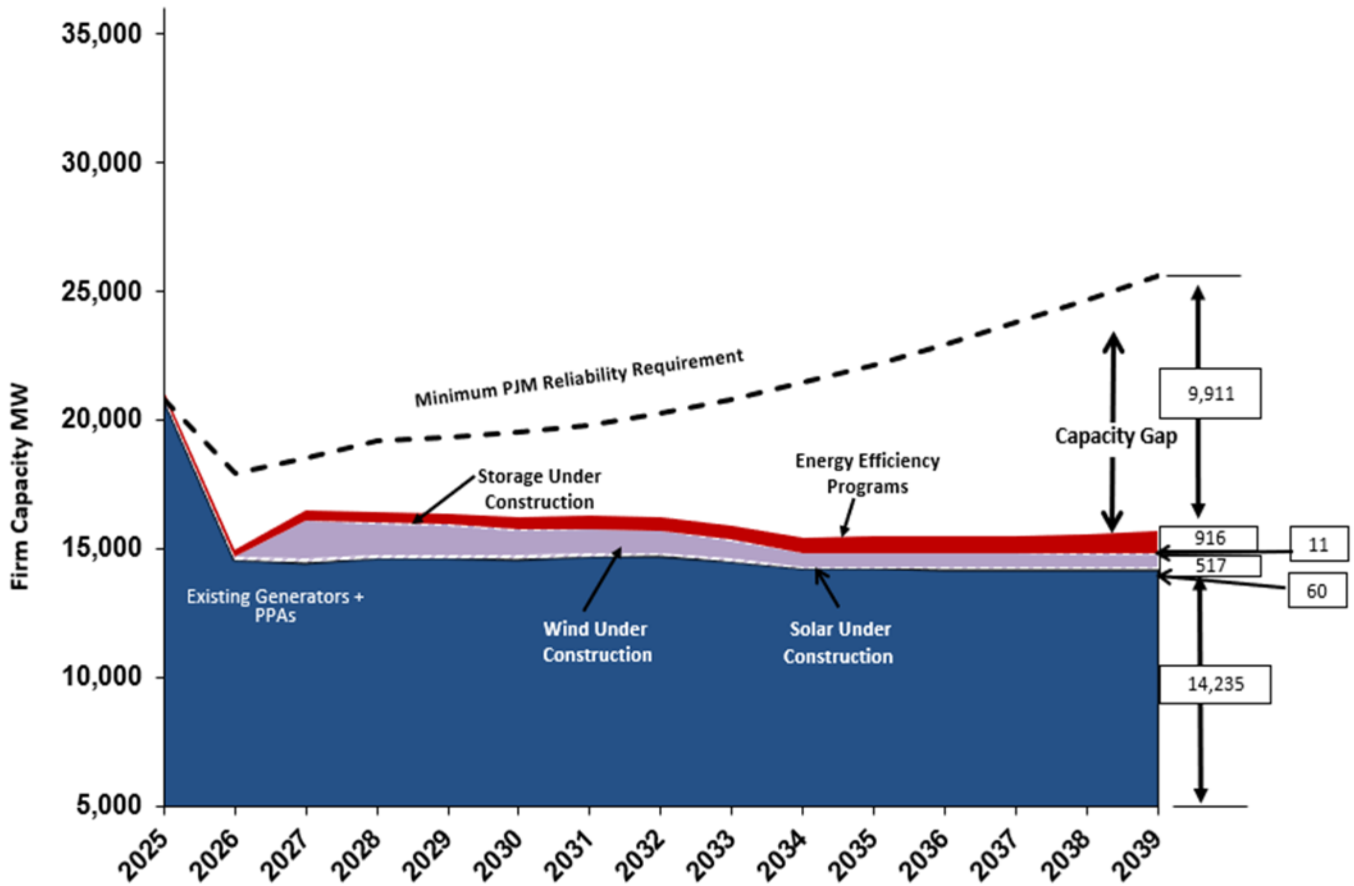
RECs



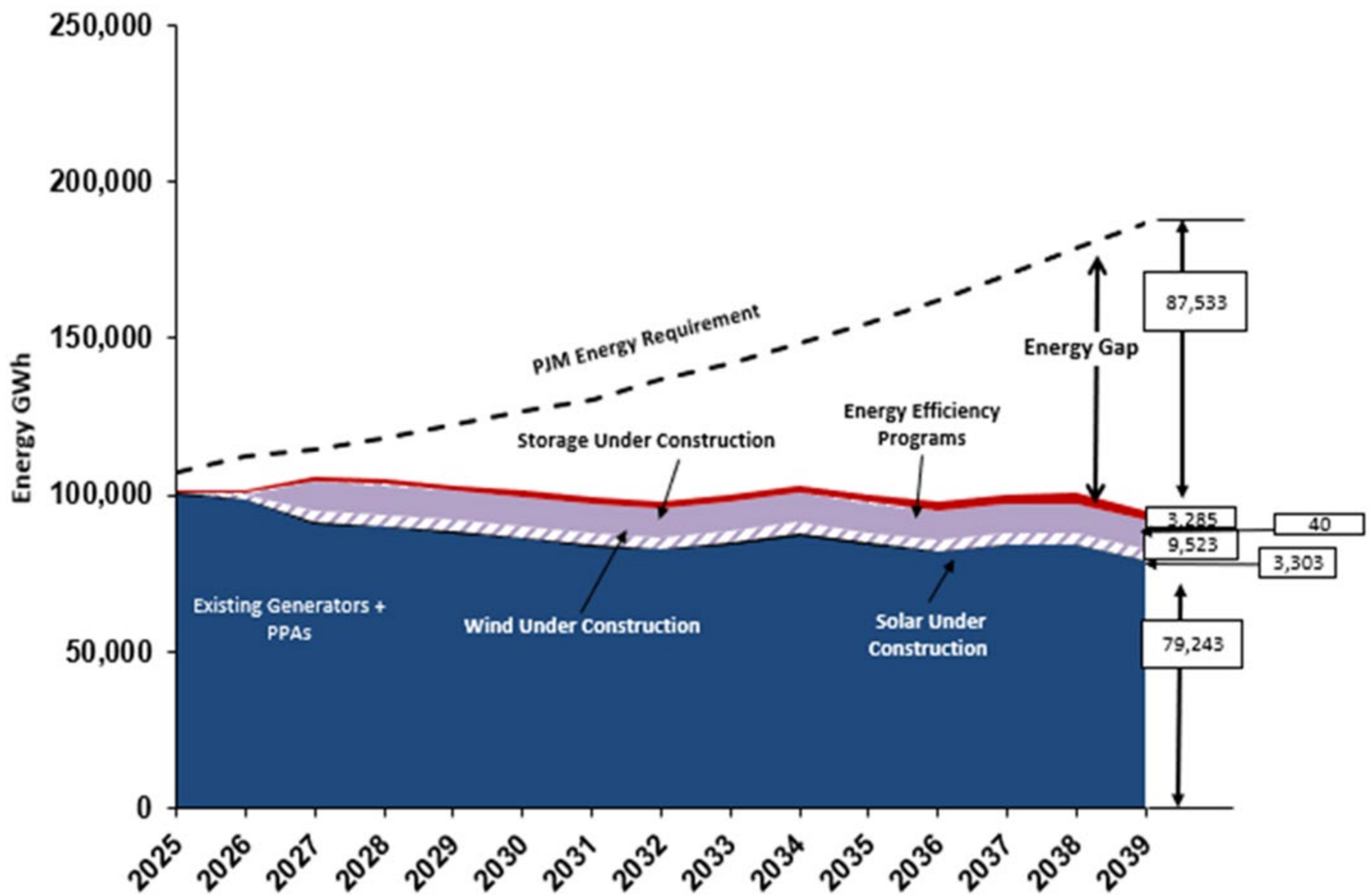
Appendix 5C: REC RPS Only with EPA – Winter Capacity Chart (Net of DSM/EE)



Appendix 5C: REC RPS Only without EPA – Current Company Capacity Position (2025 to 2039)

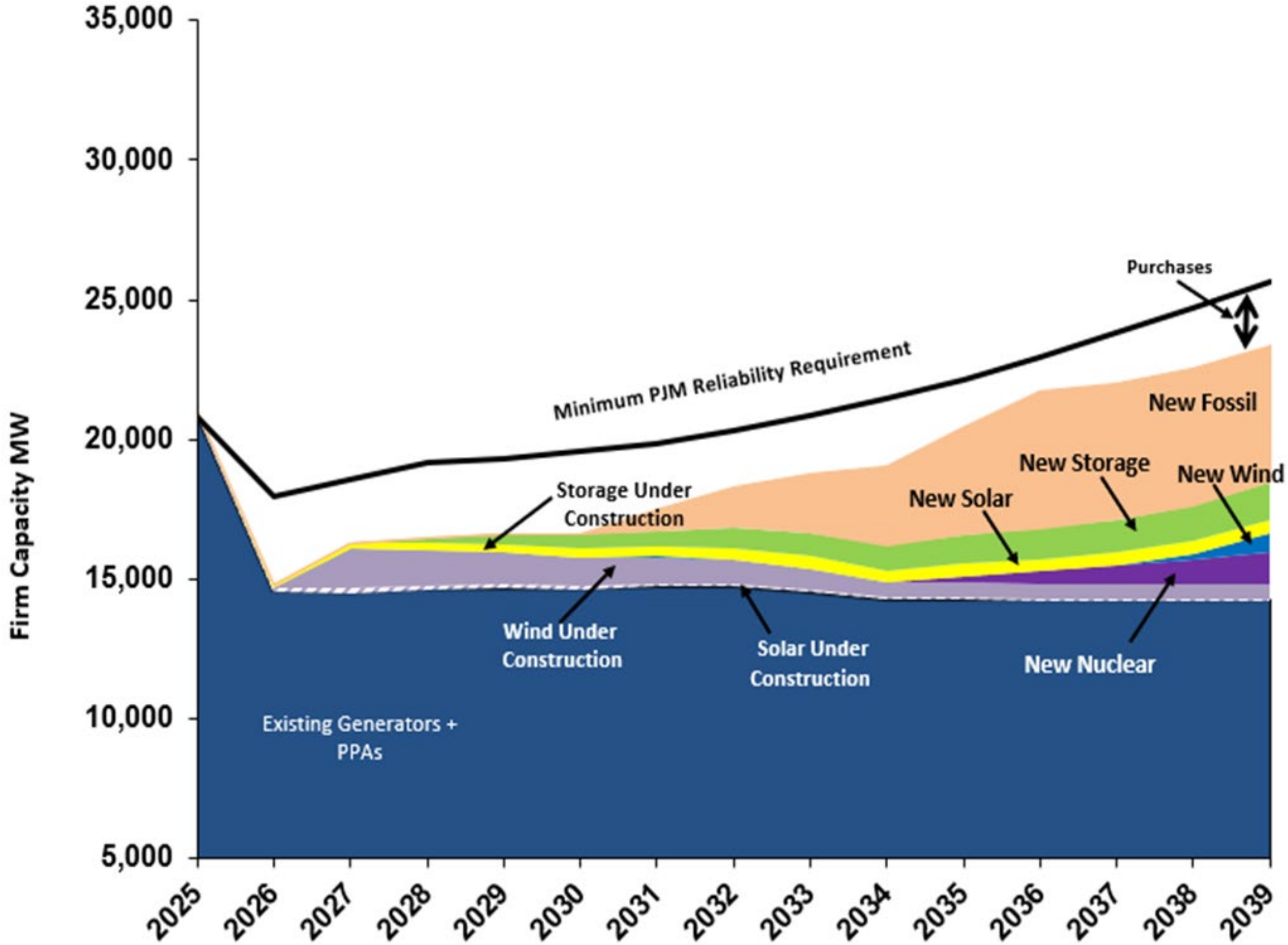


Appendix 5C: REC RPS Only without EPA – Current Company Energy Position (2025 to 2039)



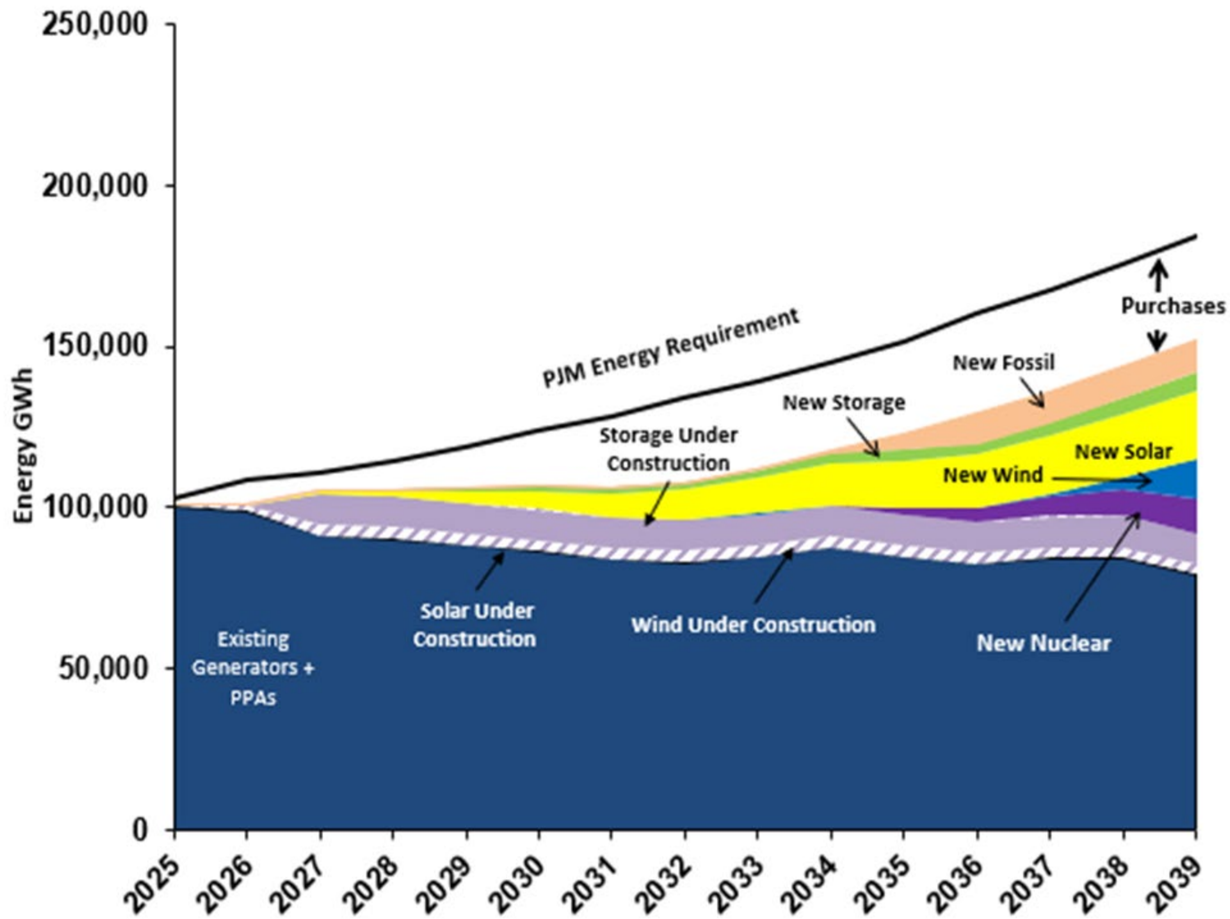
Appendix 5C: REC RPS Only without EPA – Summer Capacity, Energy, and RECs

Capacity (Net of DSM/EE)



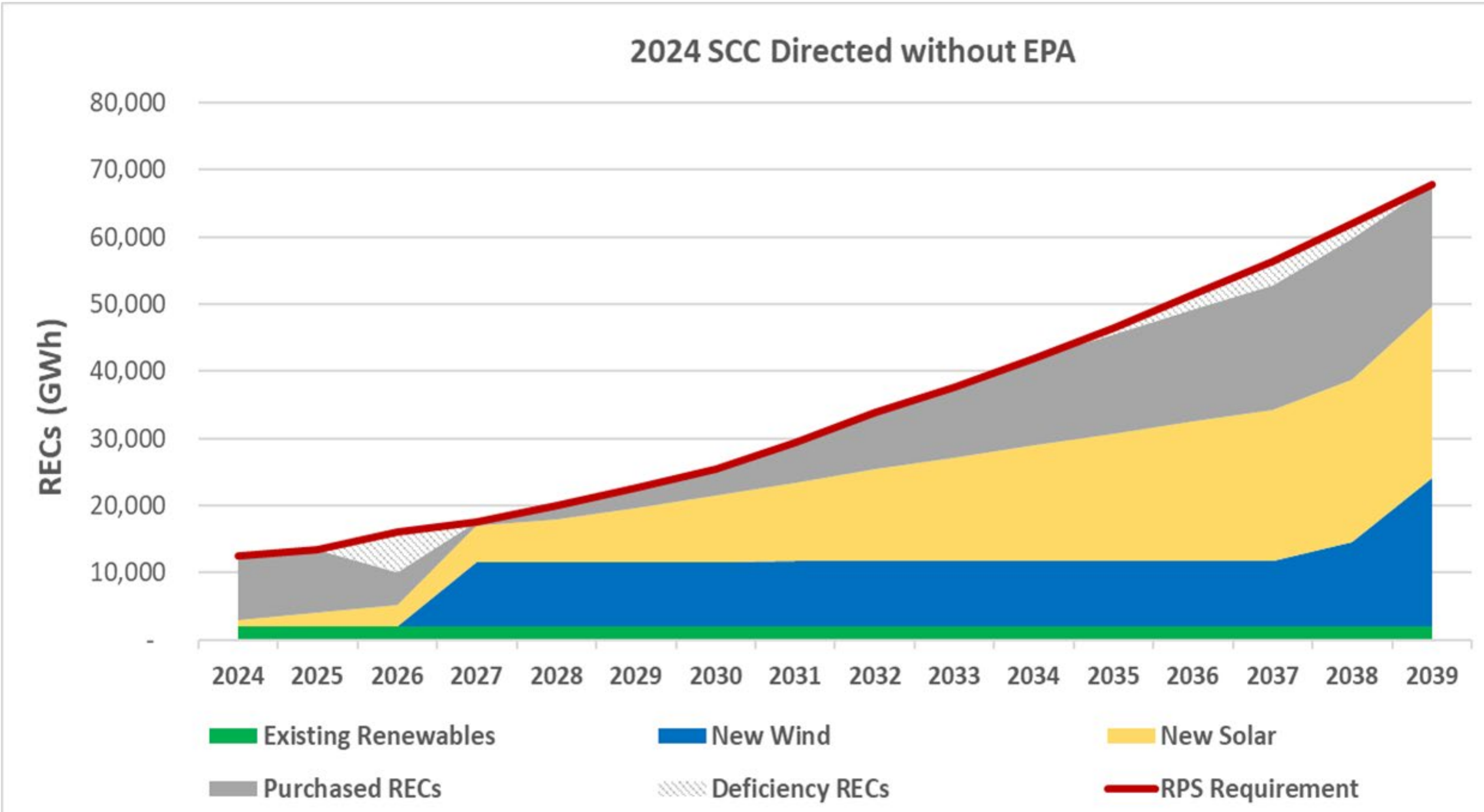
Appendix 5C: REC RPS Only without EPA – Summer Capacity, Energy, and RECs

Energy (Net of DSM/EE)

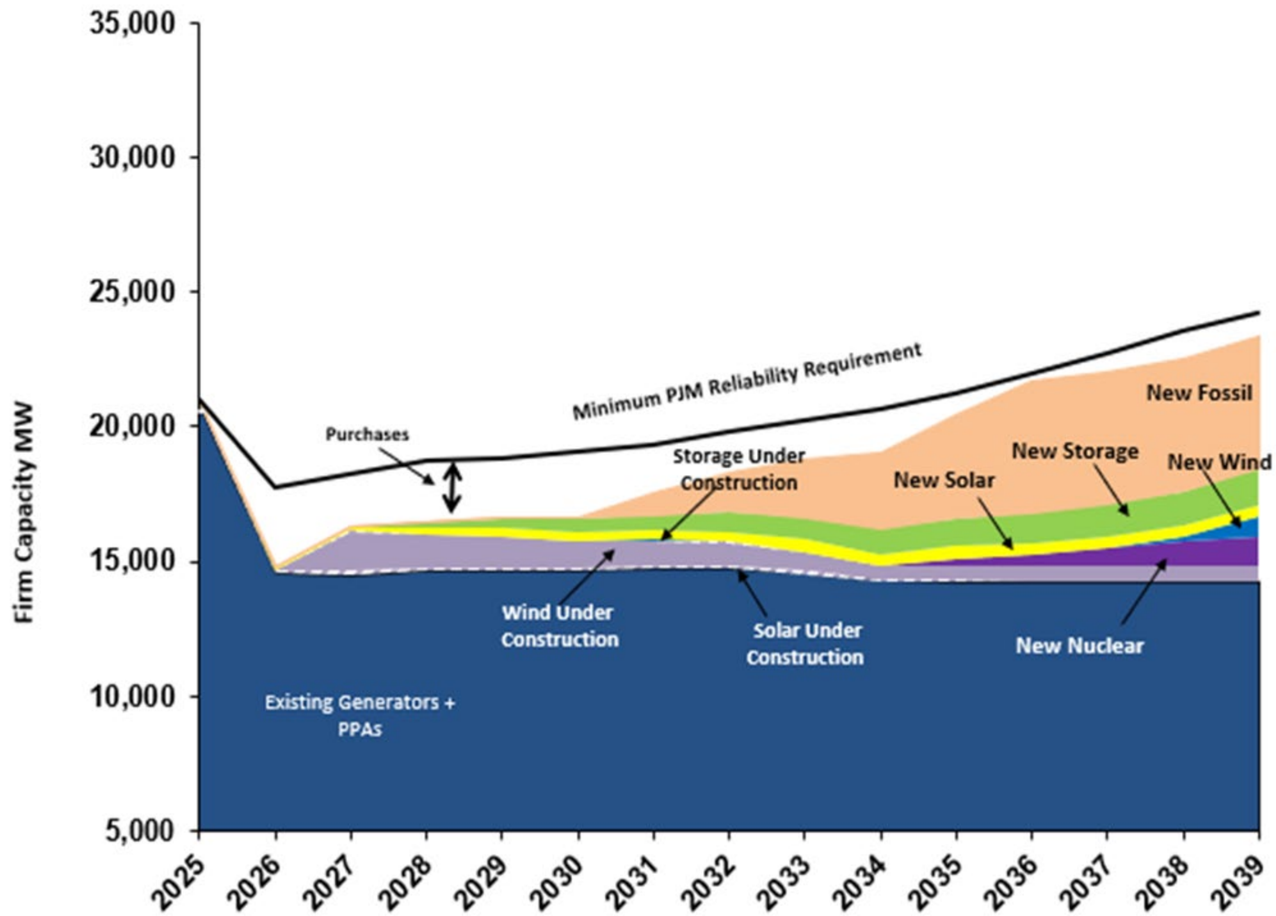


Appendix 5C: REC RPS Only without EPA – Summer Capacity, Energy, and RECs

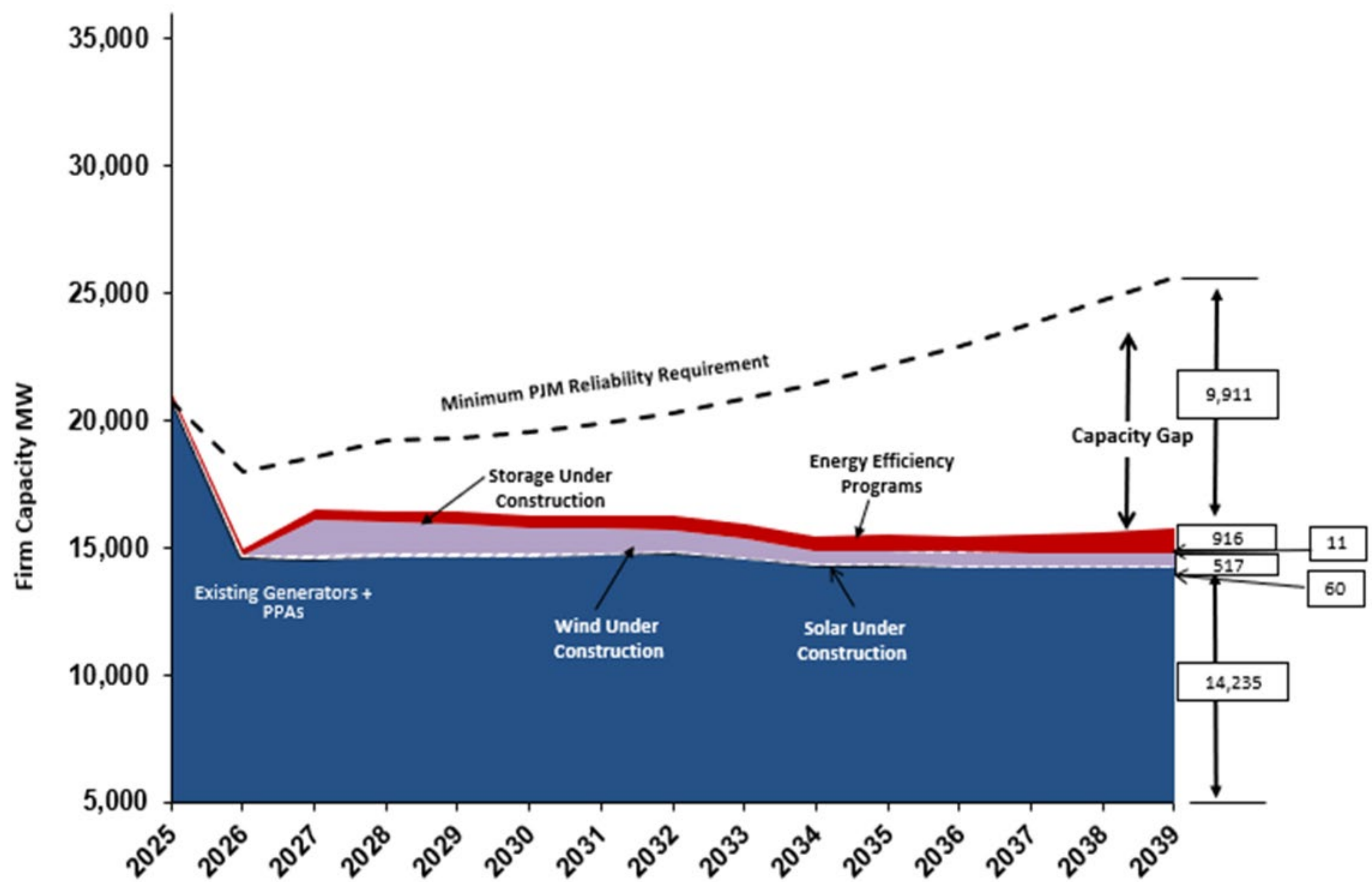
RECs



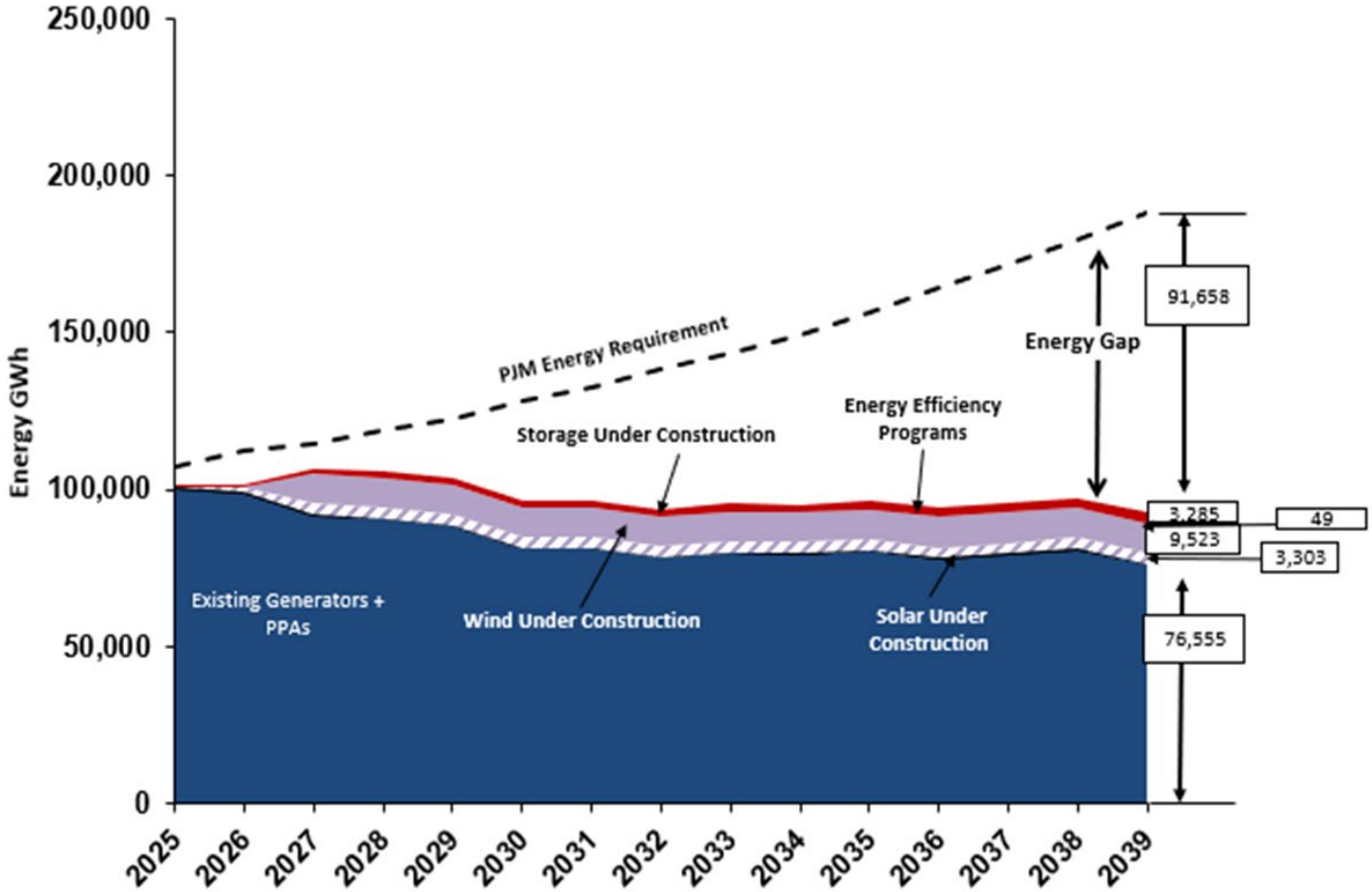
Appendix 5C: REC RPS Only without EPA – Winter Capacity Chart (Net of DSM/EE)



Appendix 5C: VCEA with EPA – Current Company Capacity Position (2025 to 2039)

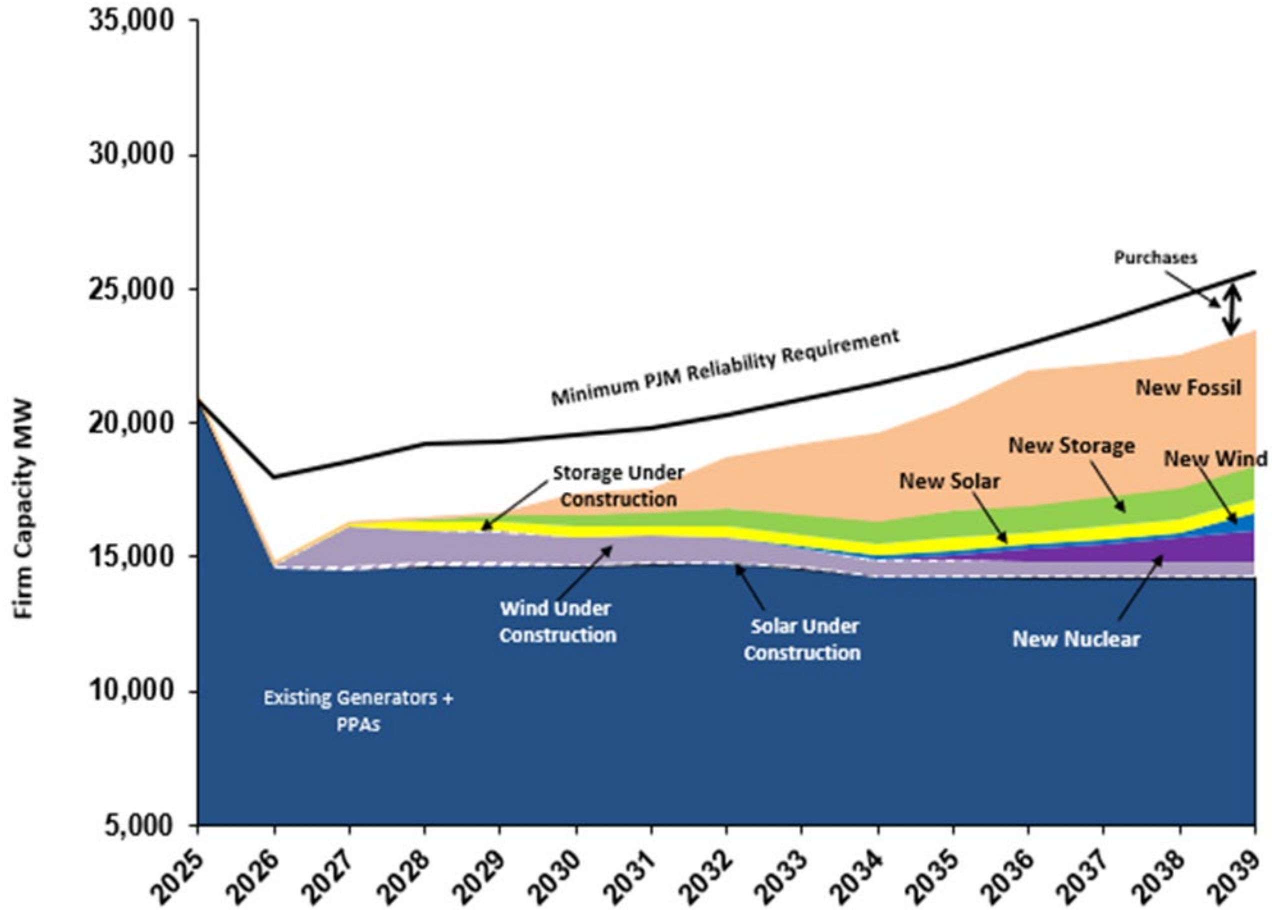


Appendix 5C: VCEA with EPA – Current Company Energy Position (2025 to 2039)



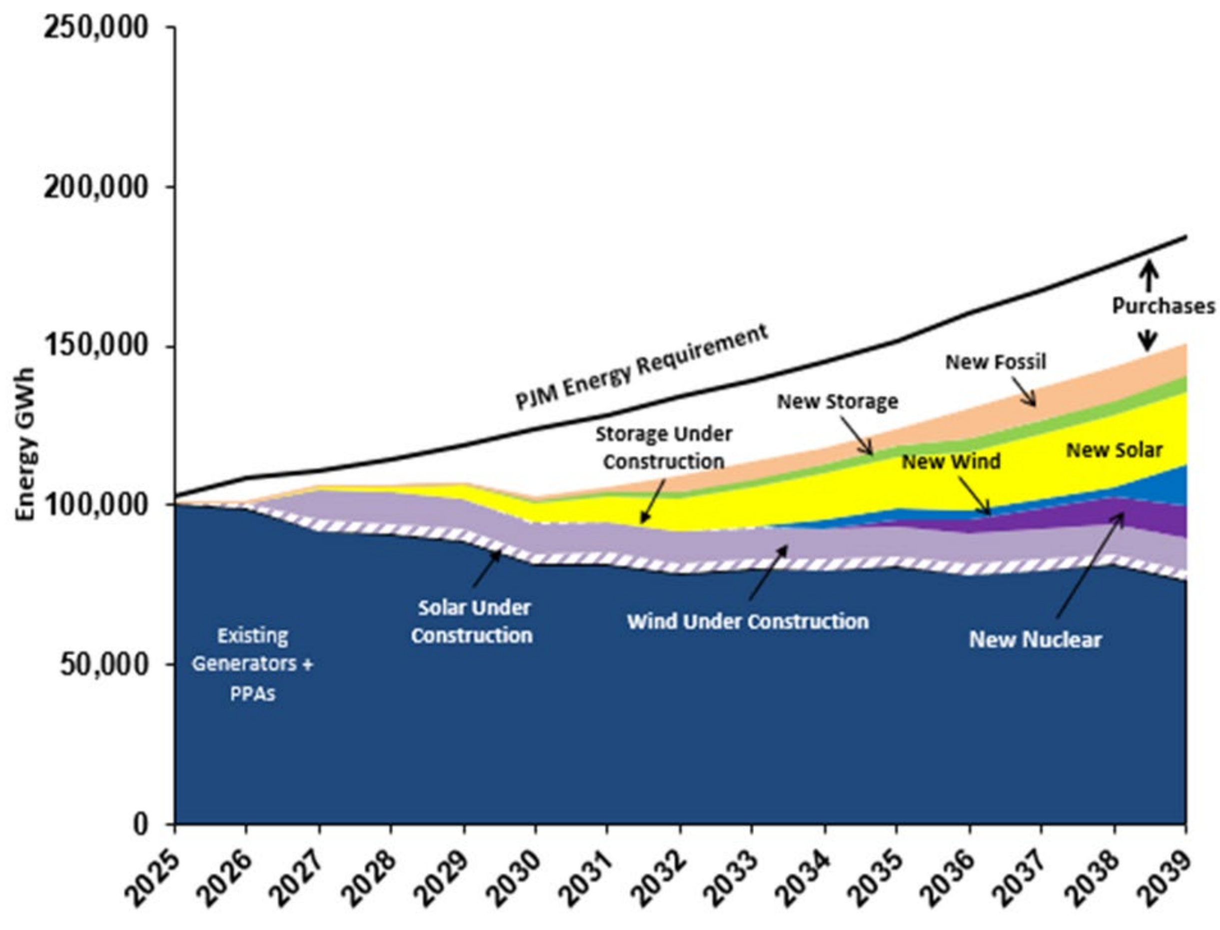
Appendix 5C: VCEA with EPA – Summer Capacity, Energy, and RECs

Capacity (Net of DSM/EE)



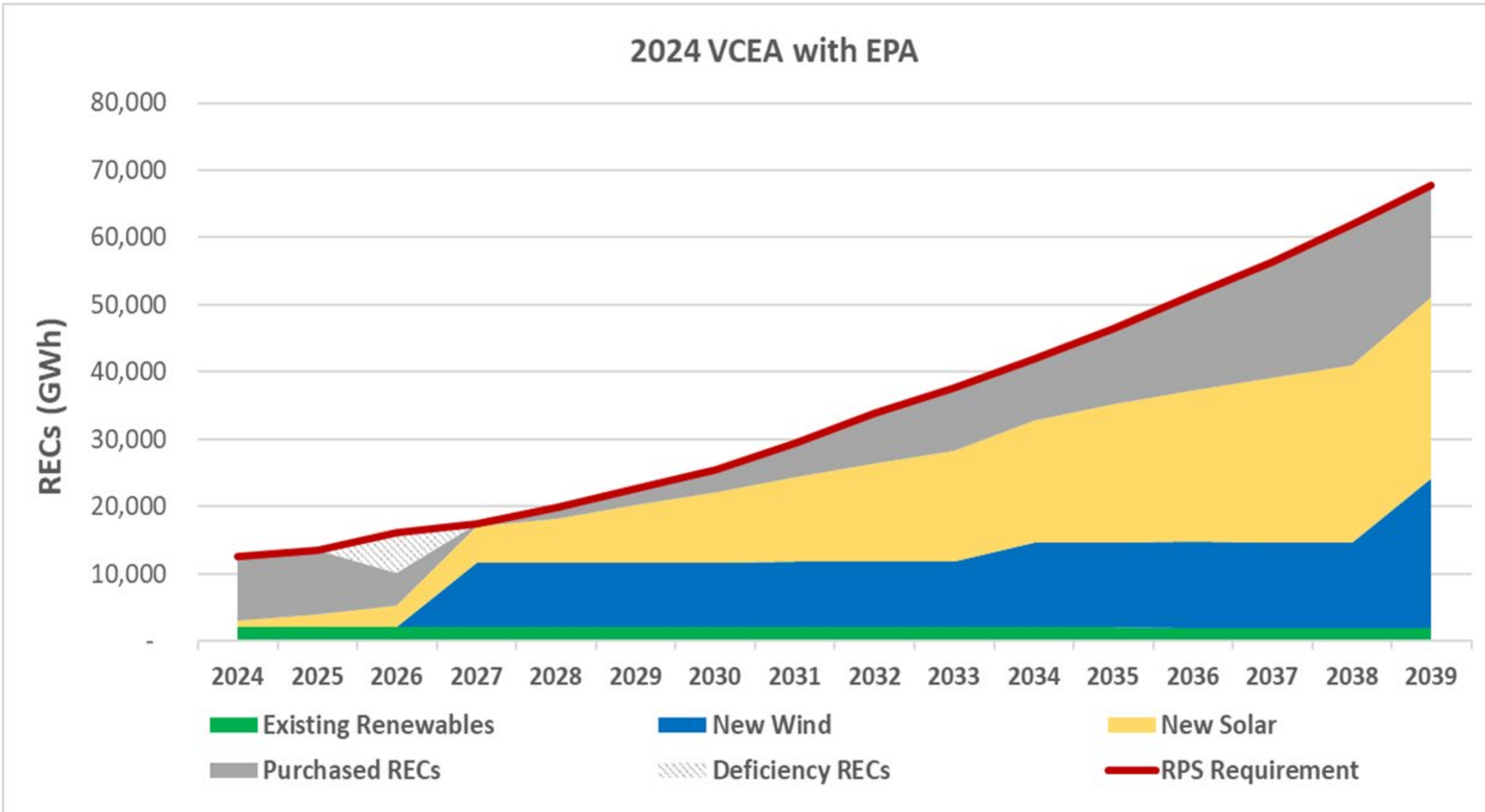
Appendix 5C: VCEA with EPA – Summer Capacity, Energy, and RECs

Energy (Net of DSM/EE)

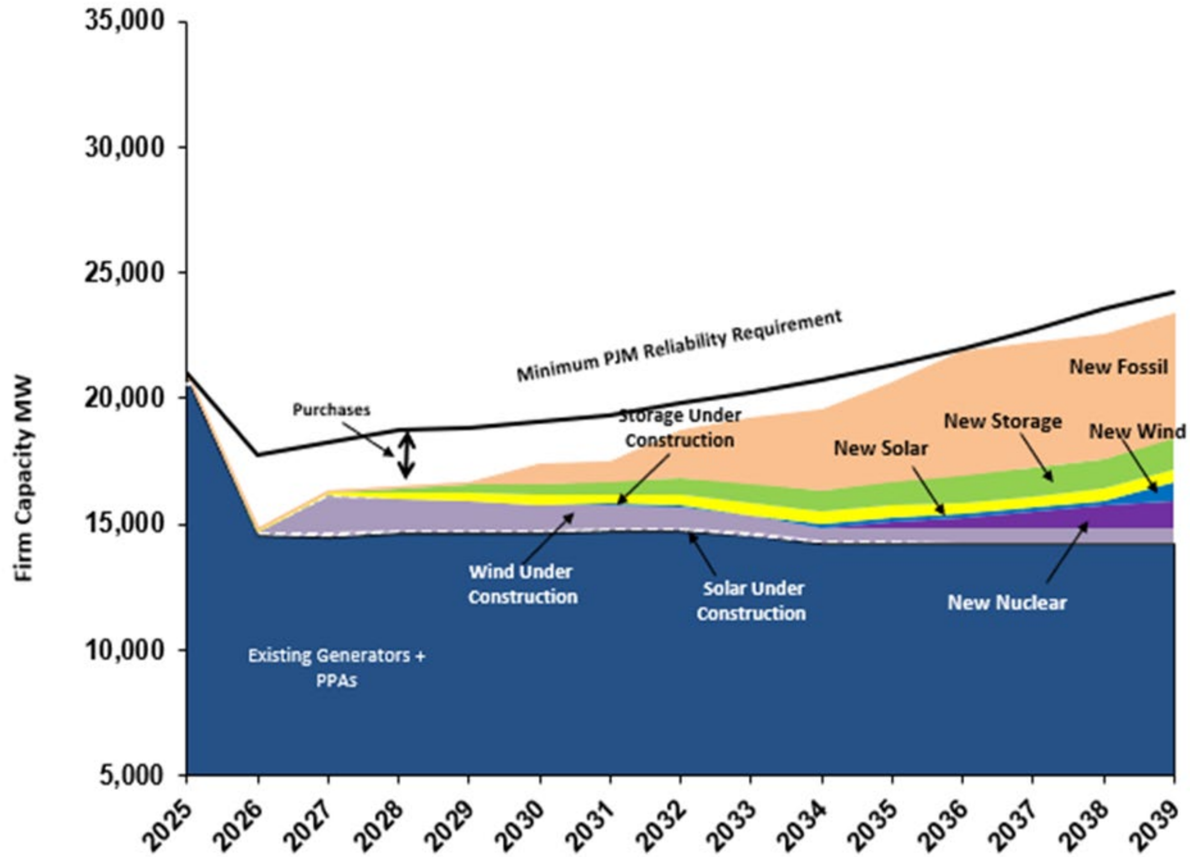


Appendix 5C: VCEA with EPA – Summer Capacity, Energy, and RECs

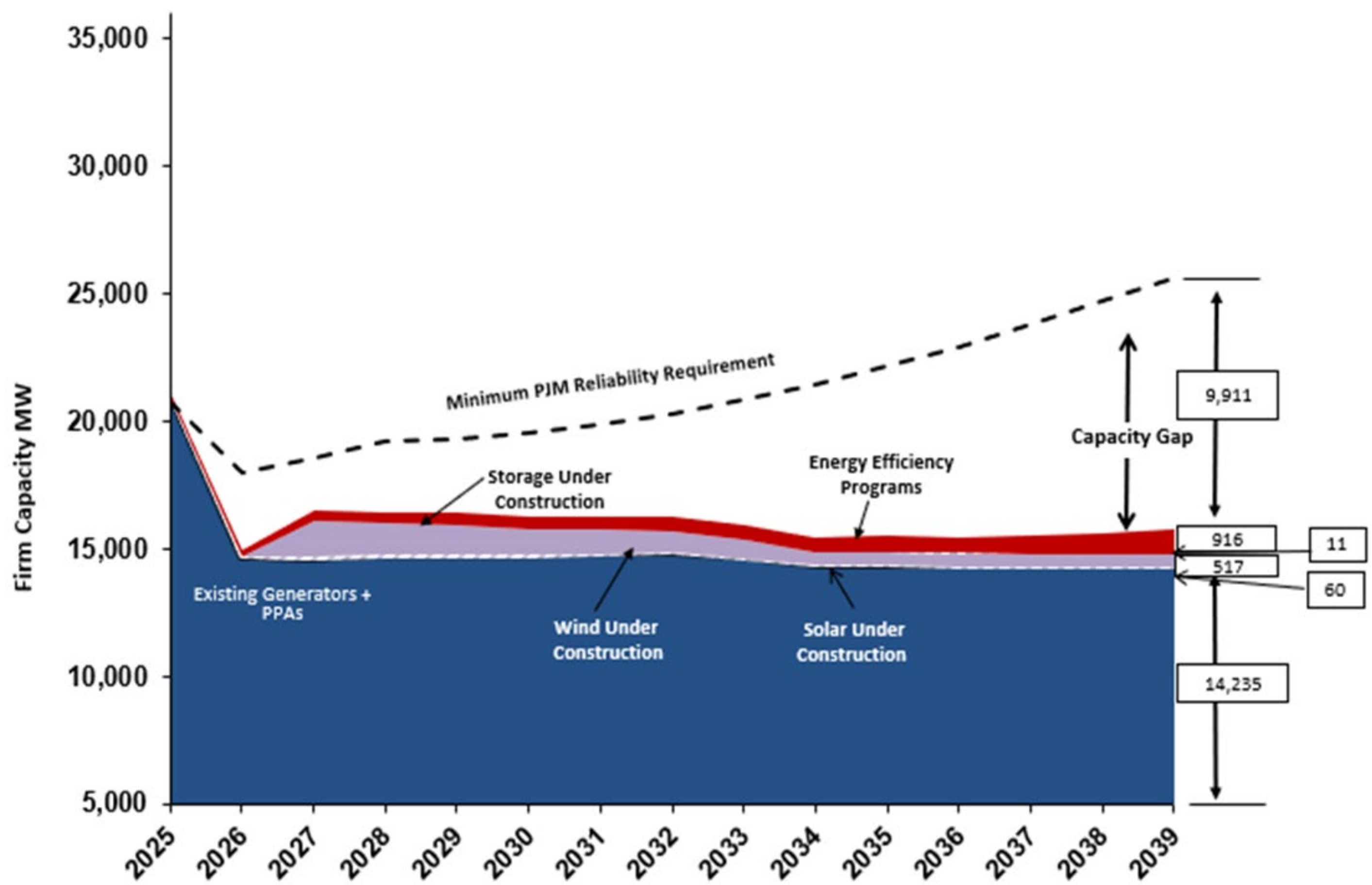
RECs



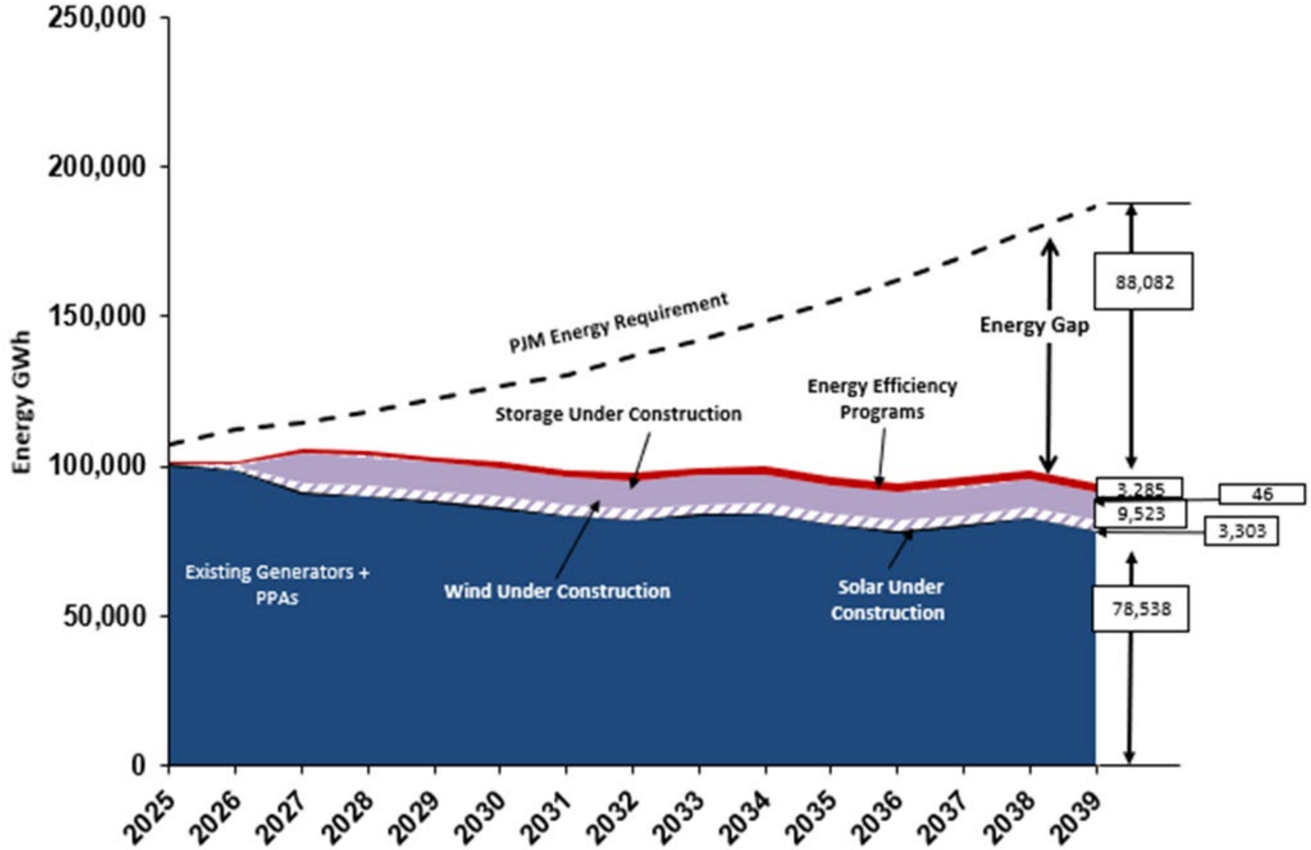
Appendix 5C: VCEA with EPA – Winter Capacity Chart (Net of DSM/EE)



Appendix 5C: VCEA without EPA – Current Company Capacity Position (2025 to 2039)

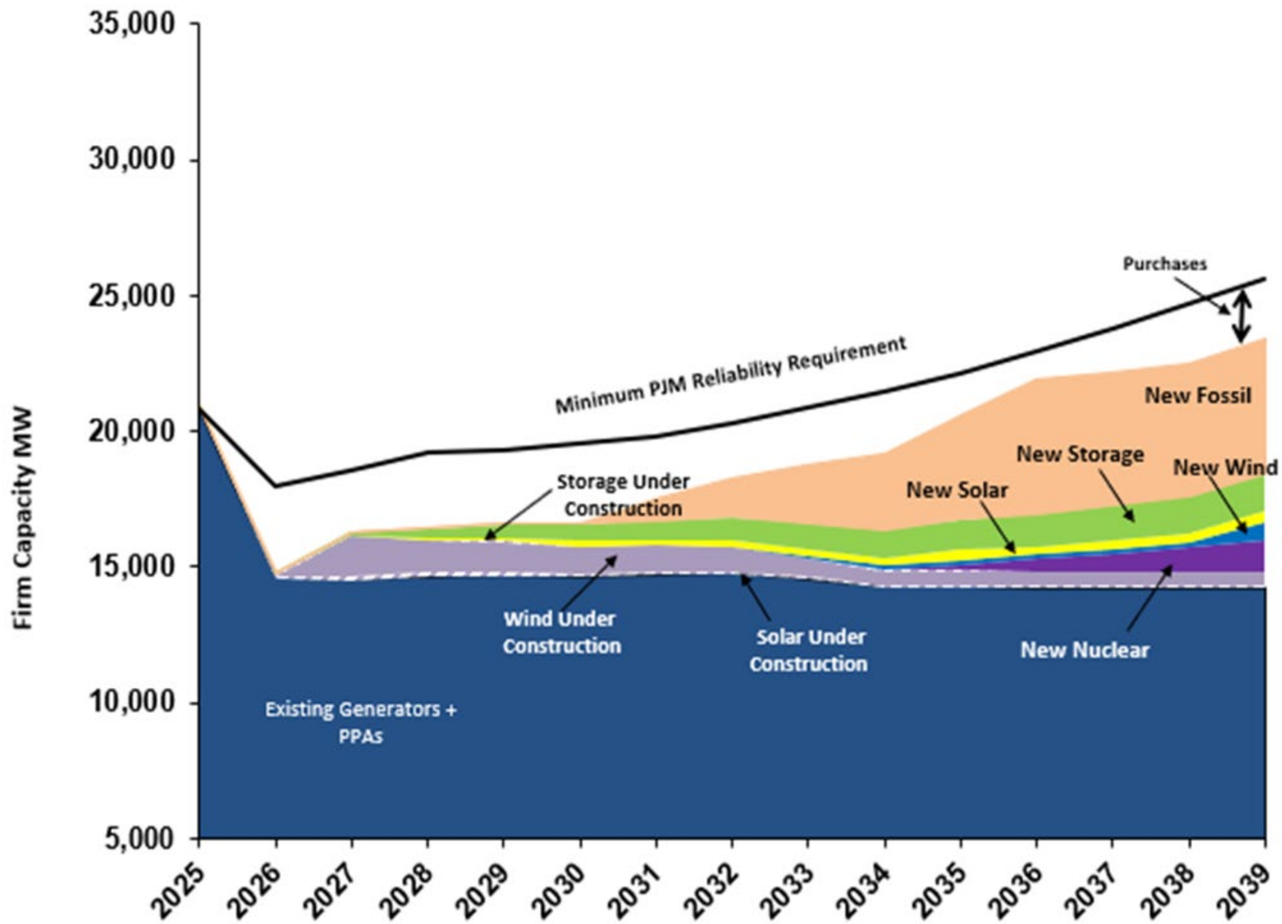


Appendix 5C: VCEA without EPA – Current Company Energy Position (2025 to 2039)



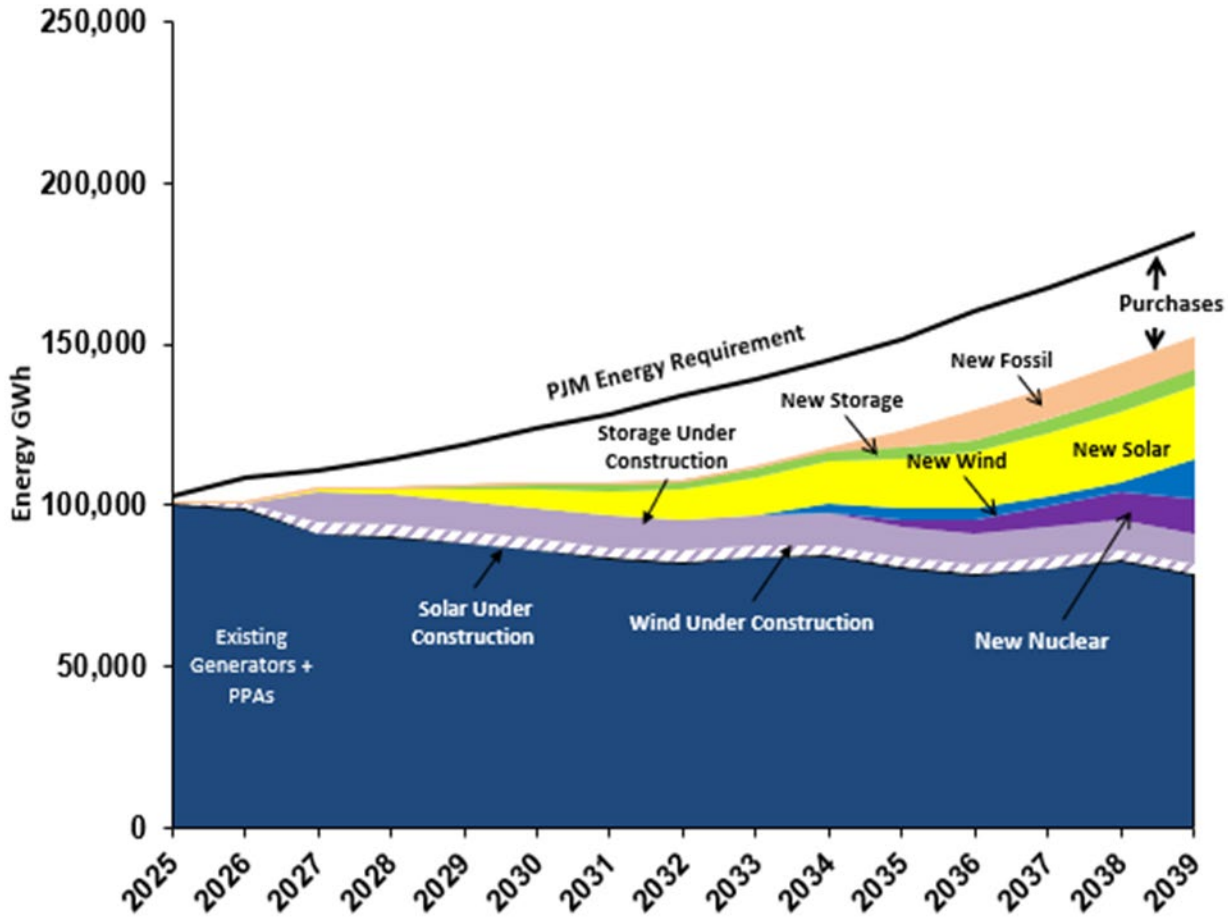
Appendix 5C: VCEA without EPA – Summer Capacity, Energy, and RECs

Capacity (Net of DSM/EE)



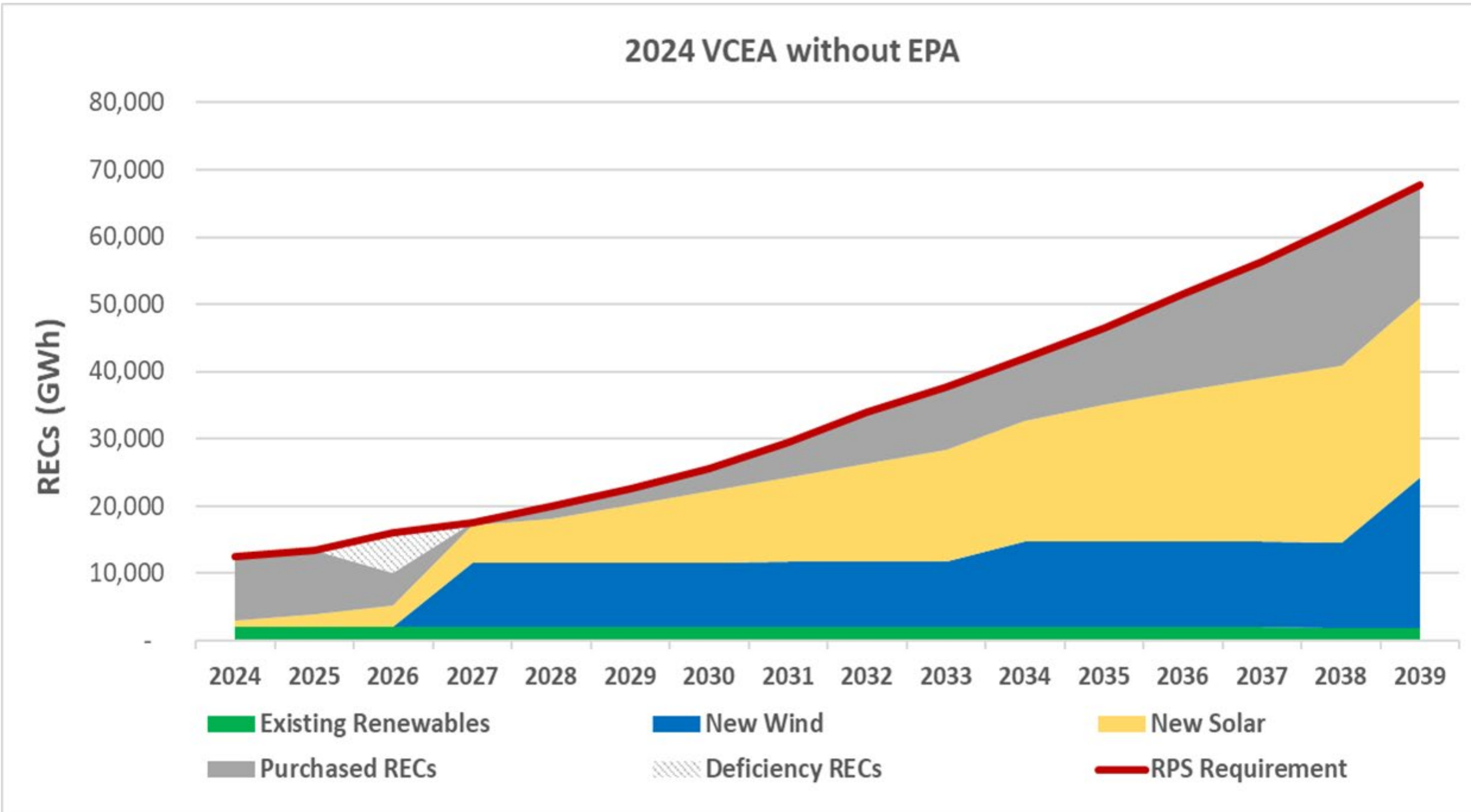
Appendix 5C: VCEA without EPA – Summer Capacity, Energy, and RECs

Energy (Net of DSM/EE)

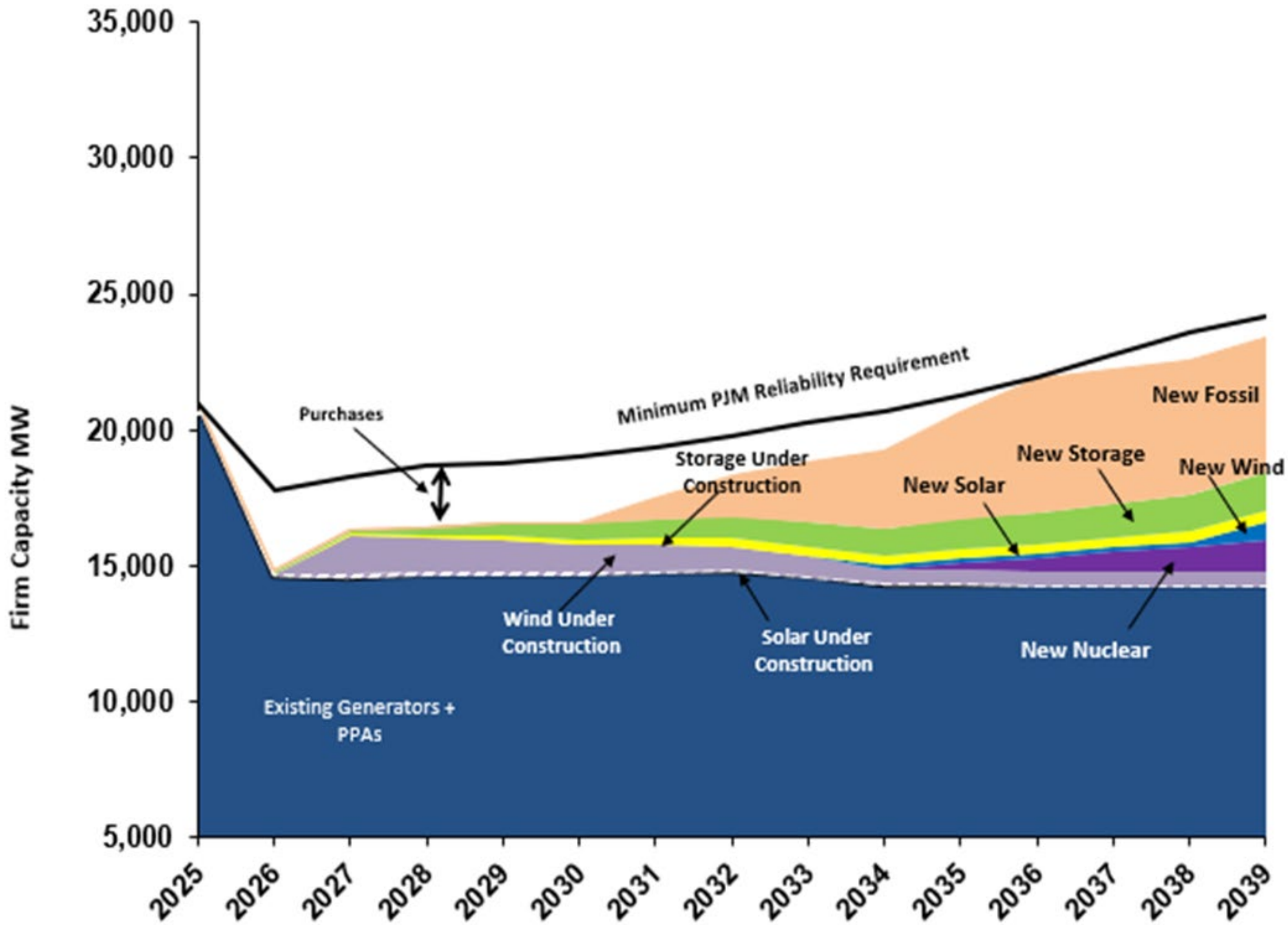


Appendix 5C: VCEA without EPA – Summer Capacity, Energy, and RECs

RECs



Appendix 5C: VCEA without EPA – Winter Capacity Chart (Net of DSM/EE)



Appendix 6A: Environmental Comparison of Generic Generation Resources

I. Background

Leading up to submittal of the 2024 IRP, the Company conducted a stakeholder engagement process as directed by Chapters 753 and 793 of the 2023 Virginia Acts of Assembly. During that process, the Company received feedback from the public asking for more information to help compare the environmental justice consequences of constructing and/or operating the different types of power generation resources contemplated by 2024 IRP modeling exercises.

The Company believes that evaluating potential effects from generic resources has limited value and that environmental justice is best evaluated on a case-by-case basis, informed by the location of the facility or project in question and project-specific characteristics. The Company, however, is committed to fully considering, and responding to the concerns of all stakeholders. Accordingly, the Company is providing Table 1: Comparison of Environmental Effects from Generic Power Generation and Storage Resource Types.

In the table, the Company evaluates the following types of generic power generation resources, including those types available to the model for selection in the 2024 IRP alternative portfolios: (1) utility-scale solar, (2) distributed solar, (3) onshore wind, (4) offshore wind, (5) battery storage, (6) pumped storage (hydro), (7) natural gas-fired simple cycle combustion turbines, (8) natural gas-fired combined cycle turbines, (9) nuclear small modular reactors ("SMR"), (10) conventional nuclear reactors, (11) coal-fired resources, and (12) biomass-fired resources.

II. Limitations on Reviewing Generic Resources

Before turning to the evaluation, it is important to note the significant limitations of evaluating the potential effects of hypothetical, generic electricity generating resources.

Generation facilities come in all shapes and sizes that are driven by numerous variables, including land use and availability, geography, topography, presence of sensitive environmental and historic resources, distance to existing electric and fuel infrastructure, local views on the placement of new generating resources, stakeholder input, permitting, and financing, among other things. For example, the extent of visual effects to local farmland, open space easements, churches, and local residences is affected by local topography, trees, and vegetation, among other things. As another example, the extent of effects to historic properties, wildlife, wetlands and other waters, and parks also depends on the nature of the local area. Without a specific design and location, an environmental assessment can only occur in the abstract.

Of equal importance is the nature, makeup, and values of the potentially affected community, including any historically disadvantaged or marginalized segments of the local population (*i.e.*, environmental justice communities). These attributes are significant for both (1) developing and implementing appropriate steps and activities to ensure an opportunity for meaningful involvement, and (2) whether and how the various types of effects that could result from the development of a project in or near the location of such community actually matter to that community. That is, not until a community understands the proposed project and any potential effects can it determine whether they are detrimental or beneficial in light of all facts and circumstances. For example, in isolation, a community might view the visual impacts of a solar project located next to an existing interstate highway to be cumulative and negative. When the community weighs those impacts against how it values the development of carbon-free resources and any related financial and employment benefits to the area, however, it may actually support the solar project and conclude that any potential visual effects related to the project are outweighed by its benefits. Put another way, what one community may find as a net negative project in terms of environmental effects, another community may find as a net beneficial project in terms of environmental effects.

In sum, evaluating the potential adverse environmental consequences of generation resources in the abstract without crucial site information and community feedback greatly limits any comparative exercise. Only after the type and severity of all the potential environmental effects resulting from a proposed action are fully understood can consideration of environmental justice occur, that is, determining whether there are any significantly adverse and disproportionate environmental effects to specific group(s) of people.

III. Interpreting the Comparison Tables

Table 1, included as part of this Appendix, provides the Company's assessment of the risk of certain potential adverse environmental effects from the construction or operation of generic, hypothetical generation resources. While some facility types are expected to create beneficial effects to the environment, only adverse effects are contemplated in this exercise.

The generic types of power generation resources included are aligned with those types available to the model for selection in the 2024 IRP alternative portfolios. Table 1 also categorizes each generic facility type in terms of reliability (*e.g.*, intermittent, peak, baseload) and notes the potential need for new electric transmission infrastructure (*e.g.*, no or likely) to connect newly constructed power generation resources to the existing grid.

The environmental effects list is designed to provide a comprehensive look at all major categories, from physical effects to the abiotic elements of the environment (*e.g.*, air, soil, water), to the biological, socio-political, and cultural aspects of the environment.

The following list defines each environmental effect addressed in Table 1:

- "Air Quality" refers to potential adverse effects on local/regional ambient air quality due to regulated criteria emissions, as defined by the Clean Air Act ("CAA") and resulting regulations.
- "Climate" refers to potential adverse effects on global climate change via emission of greenhouse gases (carbon dioxide, methane, nitrous oxide, and fluorinated gases).
- "Geology and Soils" means the potential adverse effects on geologic structure, stratigraphy, mineral resources, and soils.
- "Water" refers to potential adverse effects on surface water and groundwater quality and quantity.

- "Fish, Wildlife, and Vegetation" refers to potential adverse effects on fish, wildlife, or vegetation.
- "Cultural and Historic Resources" refers to potential adverse effects on historic, cultural, or archeological sites.
- "Land Use, Recreation, and Aesthetics" means the potential adverse effects on land uses, recreational areas, or landscape aesthetics.

For each of the potential adverse environmental effects, Table 1 provides a response for each facility type based on increasing levels of risk using a graduated color scale. A light blue symbol (●) indicates the risk of an effect is "lowest" due to a facility type; a medium blue symbol (●) indicates the risk of an effect is "medium" due to a facility type; and a dark blue symbol (●) indicates the risk of an effect is "highest" due to a facility type. For all categories, the extent and magnitude of the effect is highly dependent on facility size, site-specific characteristics.

IV. Evaluation and Comparison

For many categories of potential adverse environmental effects, the most the Company can determine for all of the resources being evaluated is that they are "possible" or may or may not be "likely." Even assuming impacts were likely, this does not dictate the potential scope of any such impacts.

When comparing generation resources in light of potential environmental effects, it is important to recognize that the construction and/or operation of these types of facilities are subject to comprehensive regulatory oversight by expert agencies at the federal, state, and local levels. Specifically, in addition to the Commission's review and approval, expert agencies implement regulatory programs aimed at protecting environmental, historical, and other resources that may be impacted by such projects. For example, the Virginia Department of Environmental Quality ("DEQ") has a comprehensive water program, including stormwater and erosion and sediment control programs, to minimize and mitigate impacts to the land and water resources. DEQ also implements comprehensive solid and hazardous waste management programs, as well as air quality and fugitive dust programs. DEQ, together with the Virginia Marine Resources Commission, and in cooperation with the U.S. Army Corps of Engineers, implements federal and state waters and wetlands protection and mitigation programs. Federal agencies, in coordination with the Virginia Department of Historic Resources, protect, minimize, and mitigate impacts to historic, cultural, and tribal resources. Local permitting and zoning requirements (*e.g.*, special exception permits and site plan approvals) protect against visual, noise, and traffic impacts.

To the extent there are possible adverse environmental consequences to communities from a specific power generation facility, there also will be avoidance, minimization, and mitigation measures achieved through the federal, state, and local permitting processes. These measures, in turn, should be accounted for when considering the severity and scope of any potential impacts.

V. Conclusion

The comparison of generic generating resources in the abstract helps provide a general understanding of the types of adverse environmental consequences that a specific project might yield. Beyond the temporary construction-related and certain operational impacts each project will have, however, simply comparing generic generation projects offers limited value and risks creating default assumptions about such projects that often are contrary to the specific facts of actual projects. The results of this evaluation demonstrate the importance of evaluating each generating project from an environmental justice perspective on a project-specific basis.

While environmental justice is traditionally focused on the adverse environmental consequences of a specific action on a specific location, the key issues considered by IRPs (*i.e.*, the availability and affordability of energy) are also critical issues that can be examined through a social justice lens. The Company believes its IRP proceedings promote environmental and social justice.

Table 1: Comparison of Environmental Effects from Generic Power Generation and Storage Resource Types

Risk Rating	Symbol	Definition
Low	● (light)	Lowest likelihood of environmental effects
Medium	● (medium)	Medium likelihood of environmental effects
High	● (dark)	Highest likelihood of environmental effects

Category	Environmental Effect	(1) Utility Scale Solar	(2) Distributed Solar	(3) Onshore Wind	(4) Offshore Wind	(5) Battery Storage	(6) Pumped Storage	(7) Natural Gas - Simple Cycle	(8) Natural Gas - Combined Cycle	(9) Nuclear - SMR	(10) Nuclear - Conventional	(11) Coal Fired	(12) Biomass
Physical	Air Quality	Low	Low	Low	Low	Low	Low	High	High	Low	Low	High	High
Physical	Climate	Low	Low	Low	Low	Low	Low	High	High	Low	Low	High	High
Physical	Geology and Soils	Medium	Low	Medium	Medium	Low	Medium	Low	Low	Low	Low	Low	Low
Physical	Water	Medium	Low	Medium	Medium	Low	High	Low	High	High	High	High	High
Biological	Fish, Wildlife, and Vegetation	Medium	Low	Medium	Medium	Low	High	Medium	Medium	Medium	Medium	Medium	Medium
Cultural	Cultural and Historic Resources	Medium	Low	Medium	Medium	Low	Medium	Low	Low	Low	Low	Low	Low
Social	Land Use, Recreation, and Aesthetics	High	Medium	High	Medium	Medium	High	Medium	Medium	Medium	Low	Low	Low
Requires New Electric Transmission		Likely	No	Likely	Likely	Likely	Likely	Likely	Likely	Likely	No	No	No
Reliability		Intermittent	Intermittent	Intermittent	Intermittent	Peak	Intermediate	Peak	Intermediate/ Baseload	Baseload	Baseload	Intermediate/ Baseload	Baseload