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
Schedule 12	DSM programs	**Appendix 3E-3** Active Programs Energy Savings **Appendix 3F-3** Recently Approved Programs Energy Savings **Appendix 3G-2** Forecasted Growth EE Energy Savings
Schedule 13	Unit size uprate and derate	**Appendix 3B-11** Planned Changes to Existing Generation Units
Schedule 14	Existing unit performance data	**Appendix 3B-1** Existing Generation Units in Service **Appendix 3B-2** Other Generation Units

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
Schedule 18	Fuel data	**Appendix 5B-18** Delivered Fuel Data
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

Table of Contents

List of Appendices

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

Appendix 5C: Capacity, Energy, and RECs for the Primary Portfolios
Appendix 6A: Environmental Comparison of Generic Generation Resources

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.

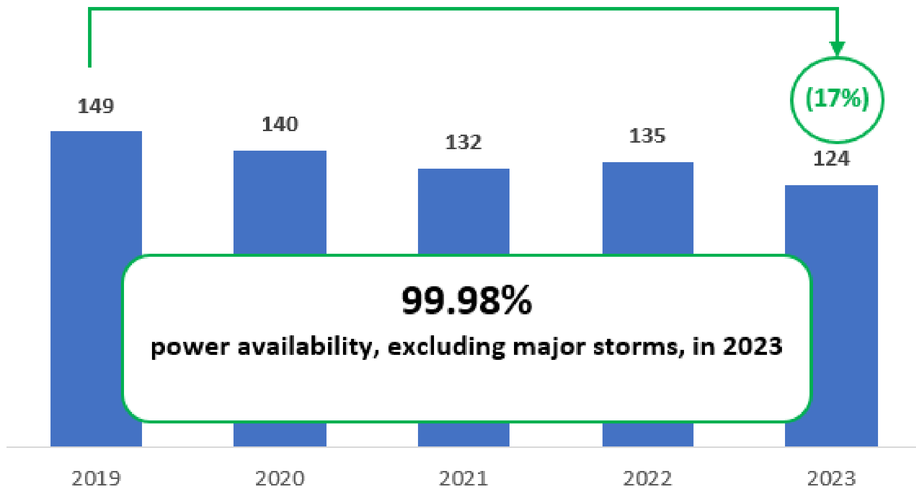
Power generation is the process of creating electricity from a primary source of energy, whether nuclear, natural gas, coal, solar, wind, or water. For power generation, reliability requires a sufficient number of generation resources and resource diversity to avoid over-reliance on any one energy source,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

[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

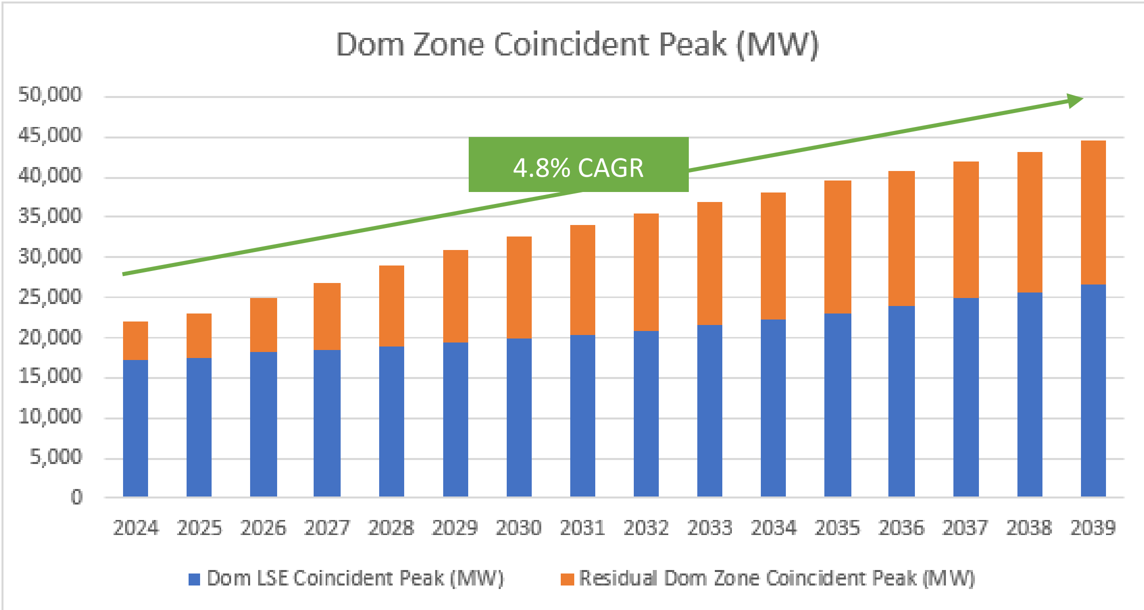
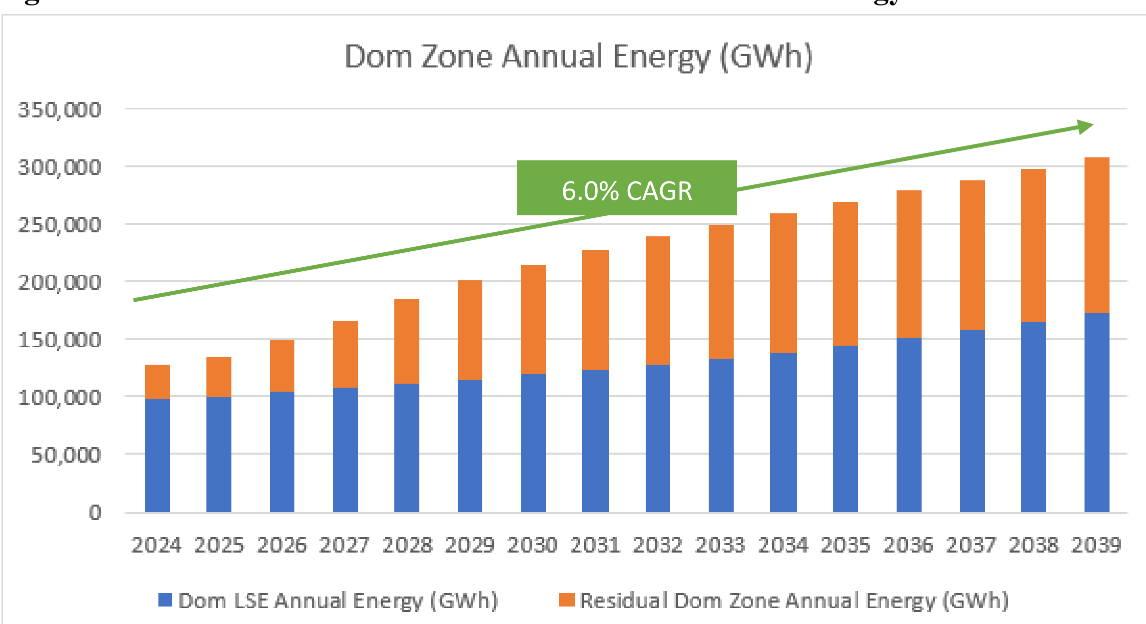


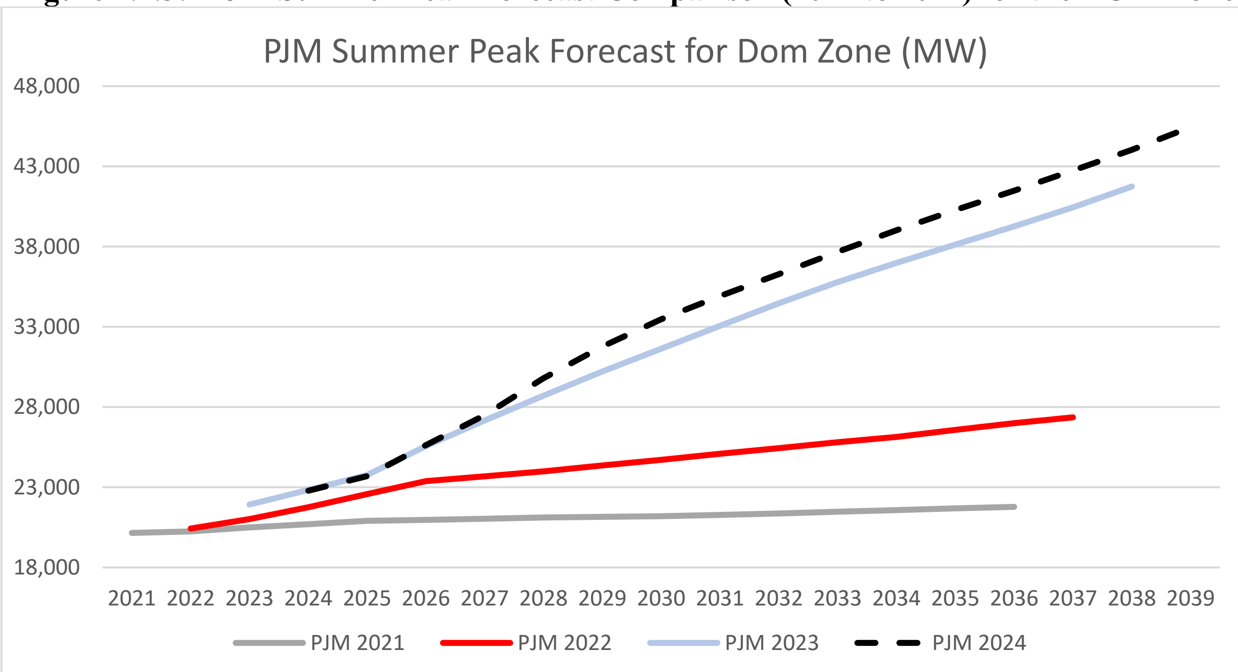
Figure 2.1.2 presents the 2024 PJM Derived Load Forecast for energy demand for the DOM Zone. Overall, the 15-year CAGR for the DOM Zone is 6.0%. The figure separates out the DOM LSE and the Residual DOM Zone portions of the zonal energy demand. This highlights the differences in the growth expected by 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]

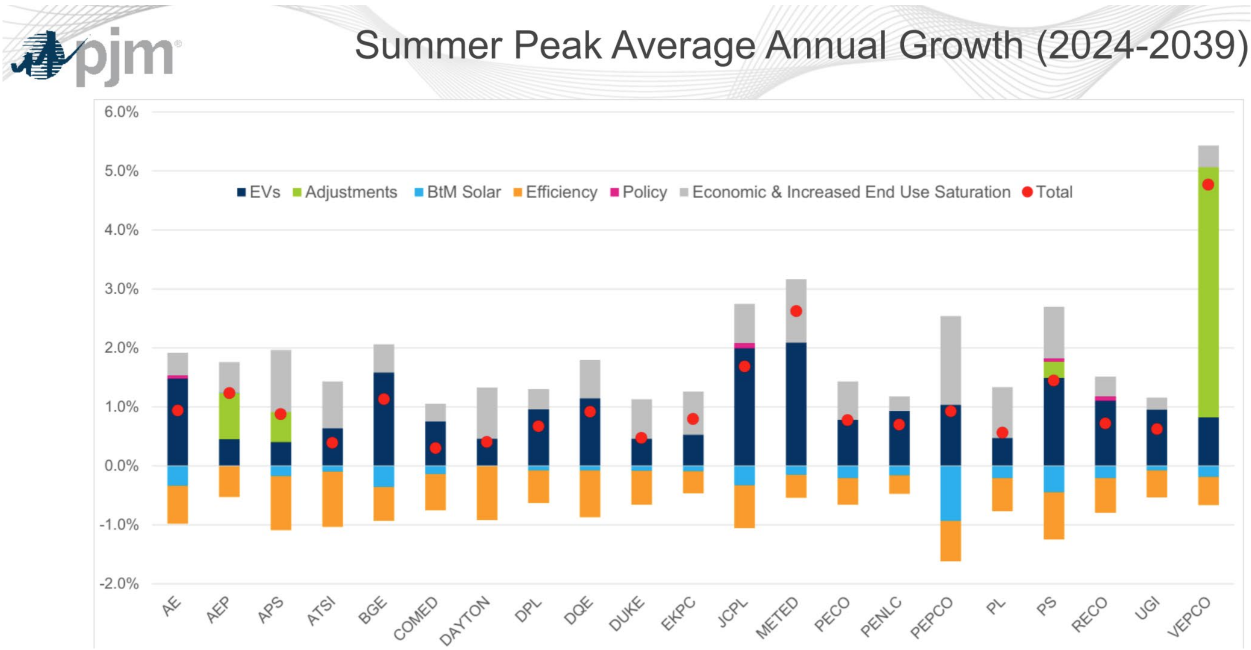
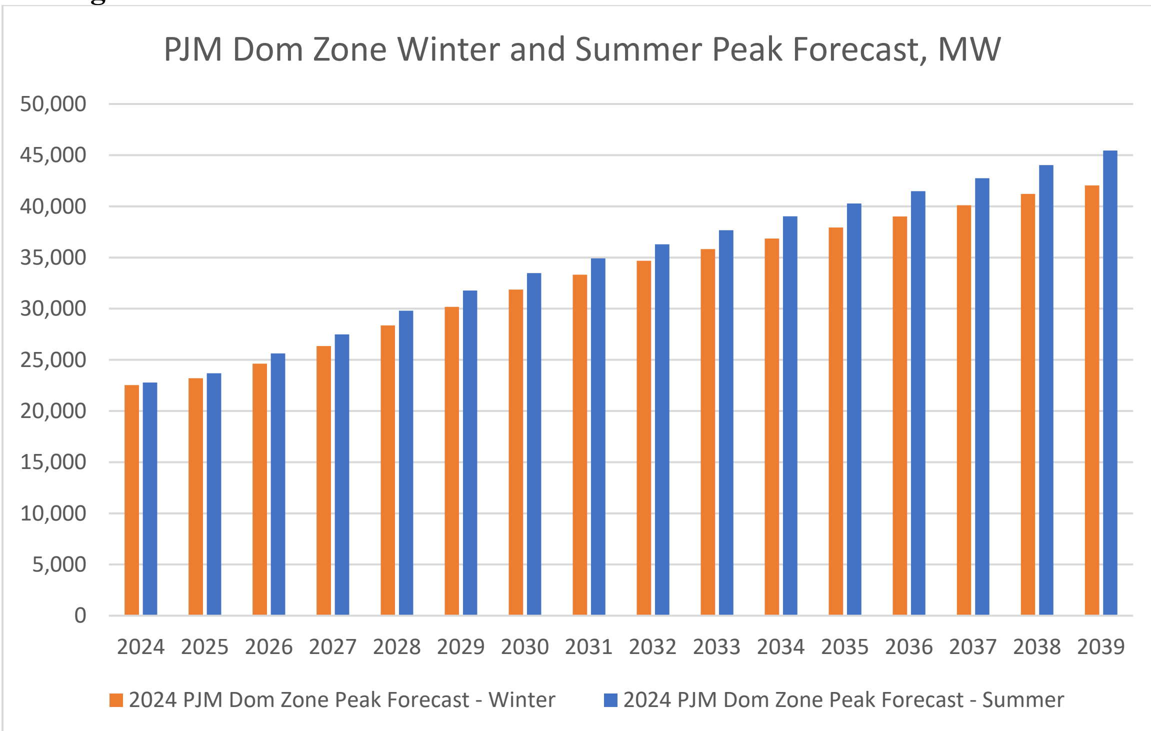


Figure 2.1.5 shows the PJM DOM Zone winter and summer forecasted peaks. Over the 15-year forecast horizon, winter and summer peaks are projected to grow by 4.2% and 4.7%, respectively, on a compound annual basis. Forecasted peaks assume normal weather, meaning that extreme weather events could cause 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.

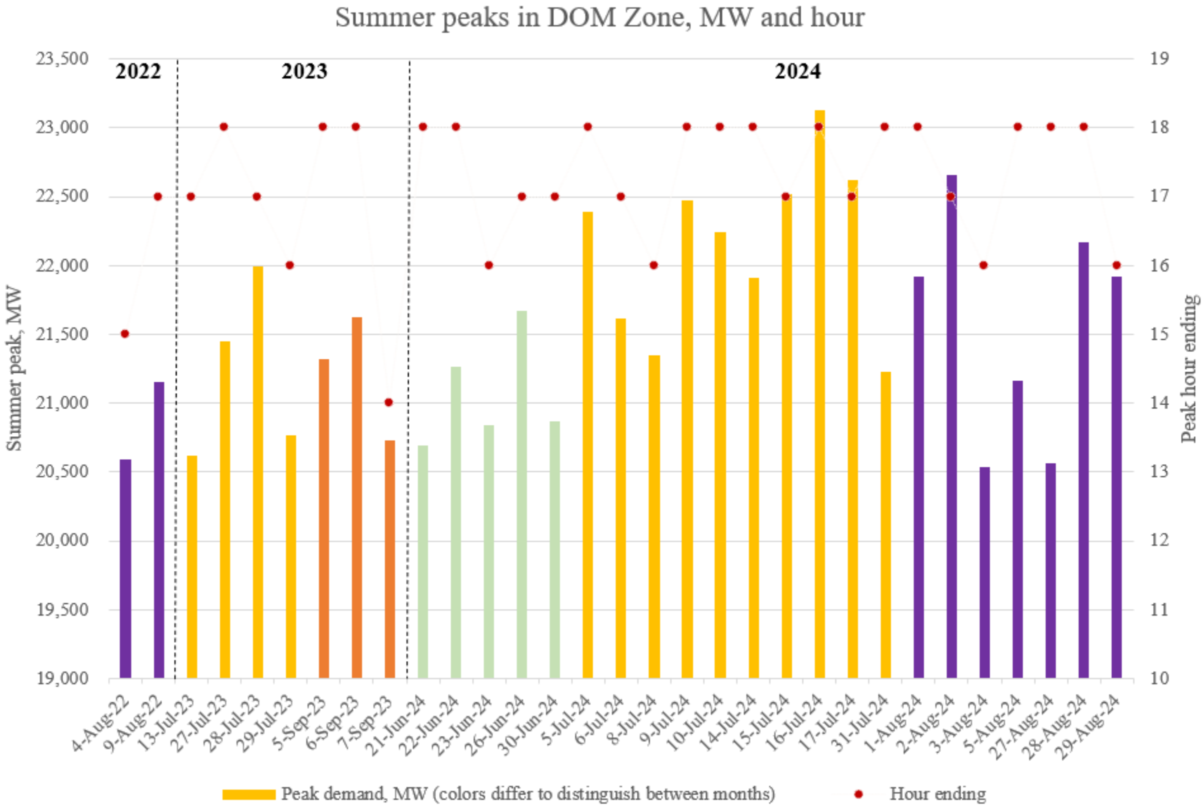
Figure 2.1.5: PJM DOM Zone Winter and Summer Peak Demand Forecast[8]



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

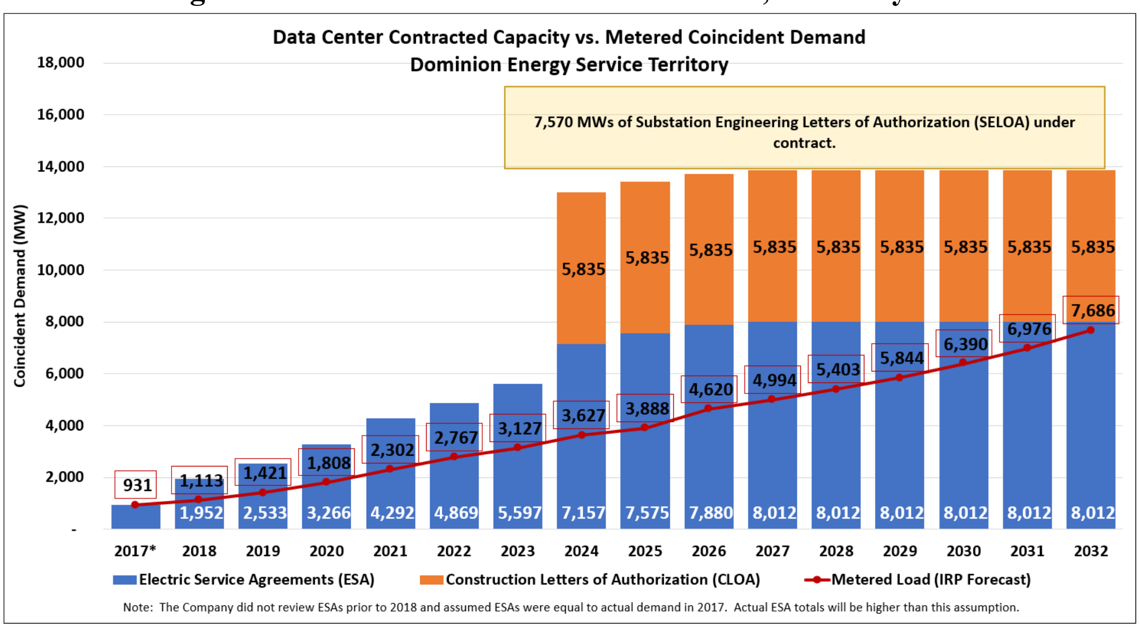
LED bulbs.[9] The big drivers of current and future growth include migration to the cloud as businesses outsource information technology functions, smartphone technology and apps, 5G technology, digitization of data, and artificial intelligence ("AI"). From storing videos to hosting AI systems that allow 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

---

[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

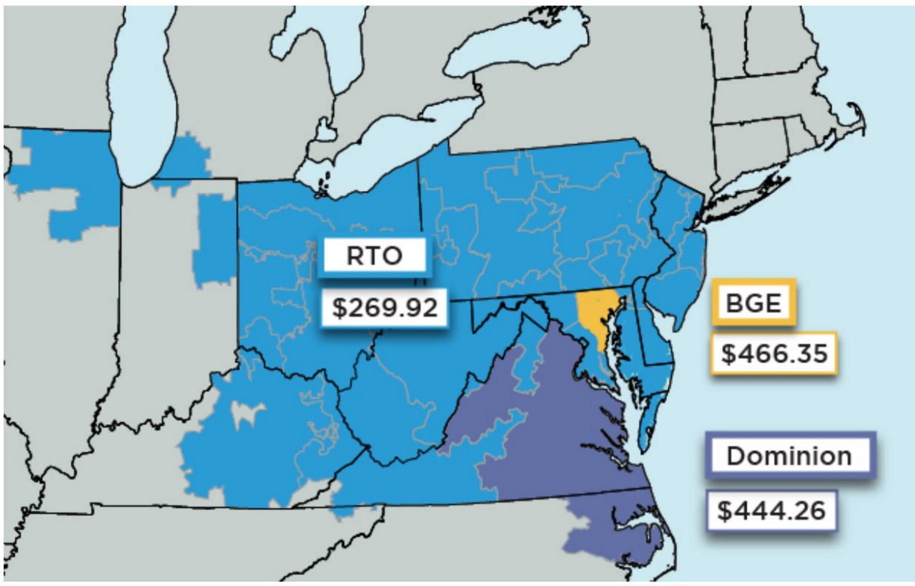
Selected Resources	2023 IRP Value	PJM ELCC Ratings (2025/2026 vs. 2034/2035 Delivery Year)
Fixed-Tilt Solar	37%	9% declining to 3%
Tracking Solar	55%	14% declining to 4%
4-hr Storage	82%	59% declining to 38%
Offshore Wind	43%	60% declining to 20%
Nuclear	PJM calculated capacity value using the EFORd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

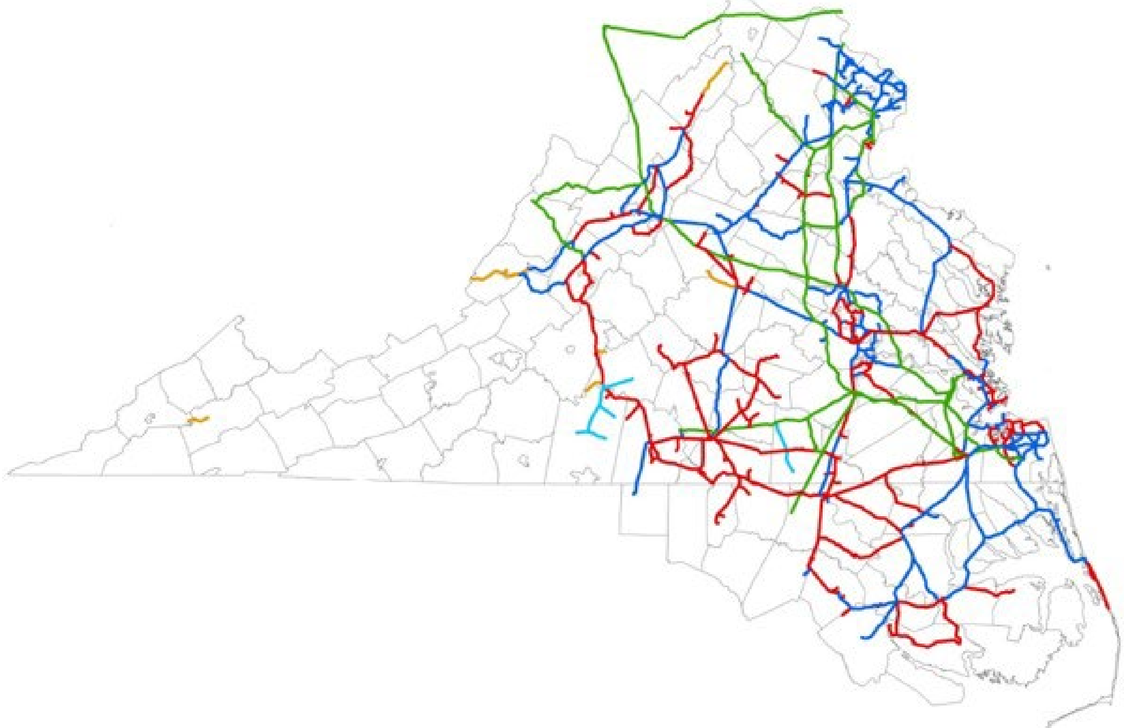
The Company also evaluates its ability to support expected customer growth through its internal transmission planning process. The results of these evaluations indicate if any transmission improvements are needed, which the Company includes in the PJM RTEP process as appropriate. The Company then seeks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

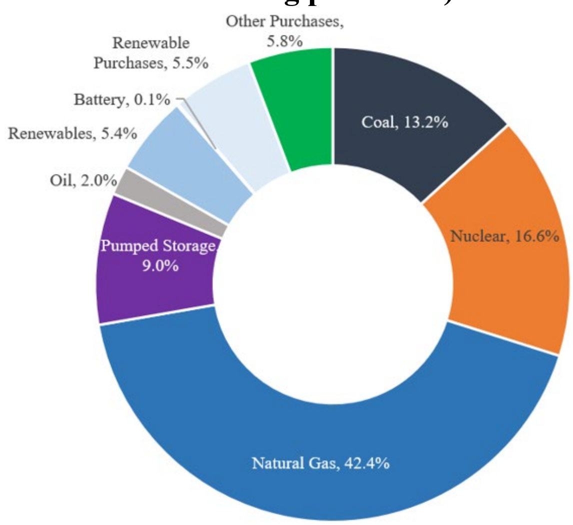
Figure 3.1.1.1: 2023 Capacity Resource Mix by Unit Type

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]

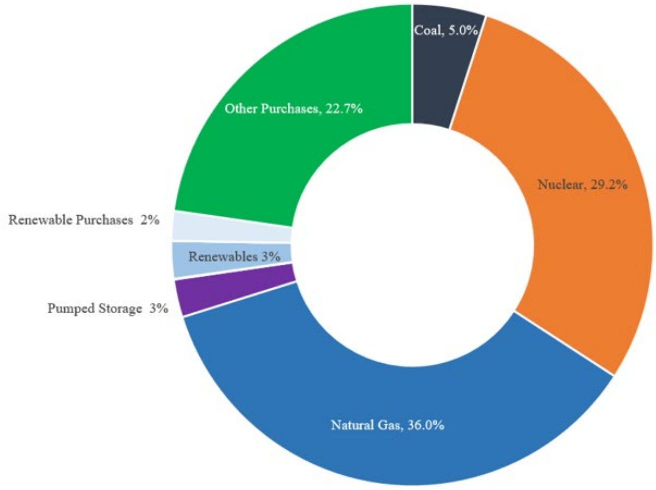
Figure 3.1.1.2: Capacity Mix (Summer Installed Capacity as of December 31, 2023, including purchases)



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.

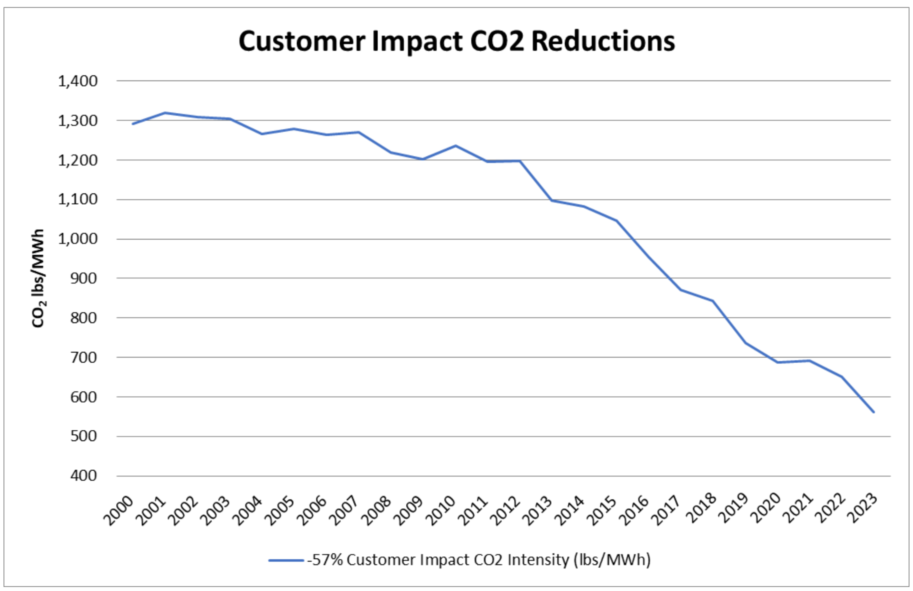
In North Carolina, the Company offers the avoided cost tariffs to qualifying facilities under the Public Utilities Regulatory Policies Act, to sell capacity and energy at the Company's published North Carolina Schedule 19 rates. The Company has 90 effective PPAs totaling approximately 692 MW (nameplate). 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.

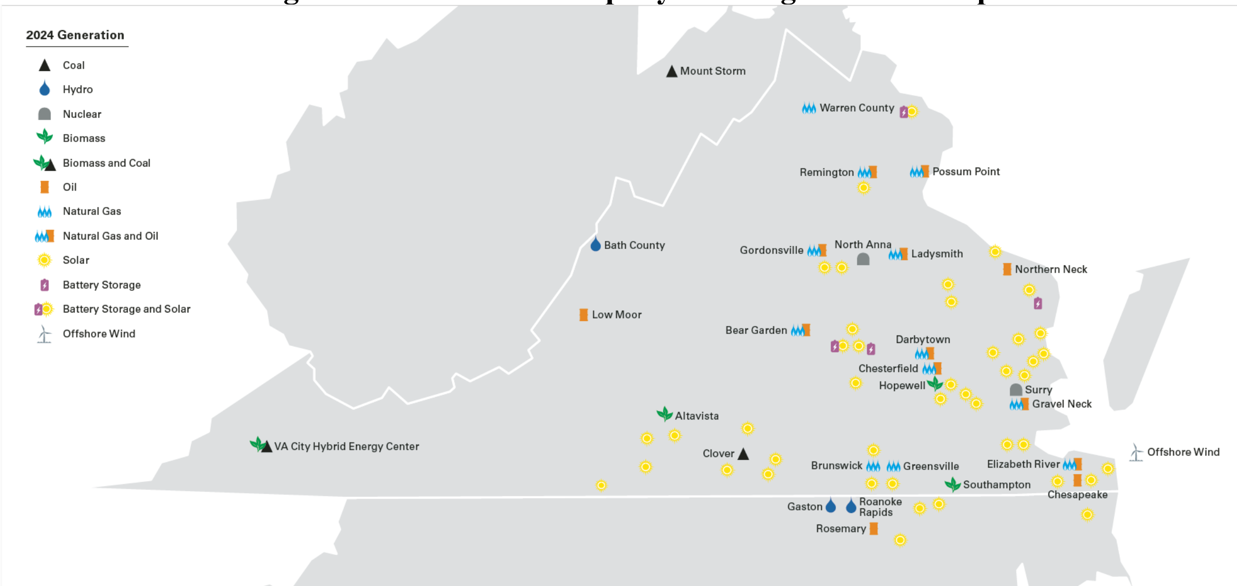
Over the past two decades, the Company has made changes to its generation mix that have significantly improved environmental performance. These changes include the retirement of certain units, the conversion of certain units to cleaner fuels, and the addition of air pollution controls. This integrated 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

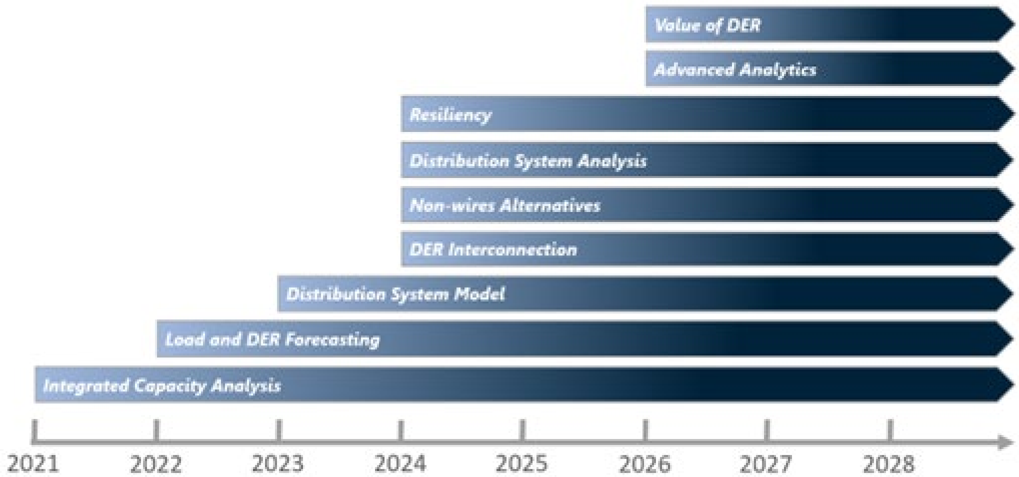
As society has grown more dependent on electricity, customers tolerance for outages has waned. The safe, reliable, and consistent grid connectivity has never been more important than it is today. Fundamental changes in the energy industry driven by the rise in DERs and expanding electrification have 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.

[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

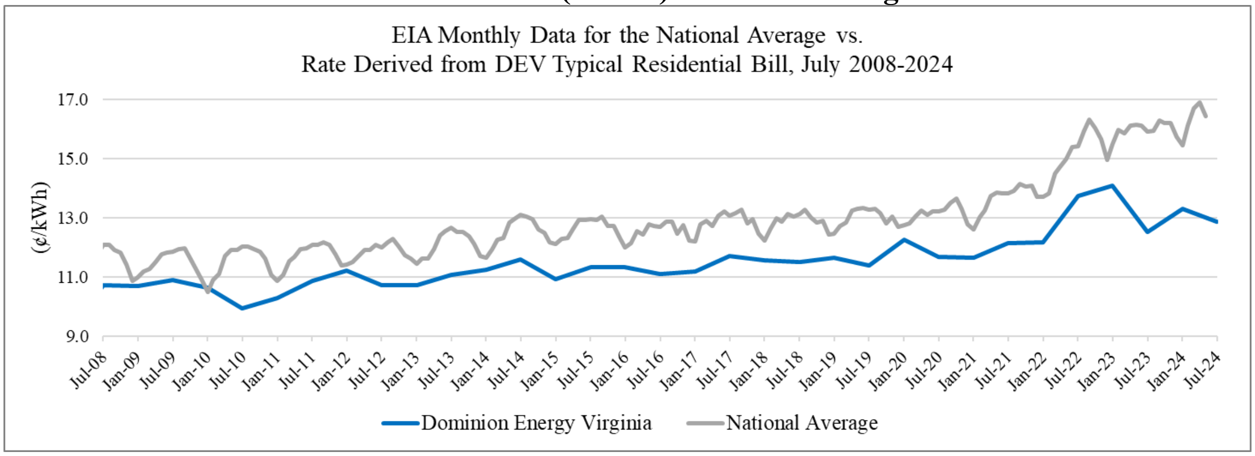


Figure 4.1.2: Historical Dominion Energy Industrial Rate vs. EIA National Average

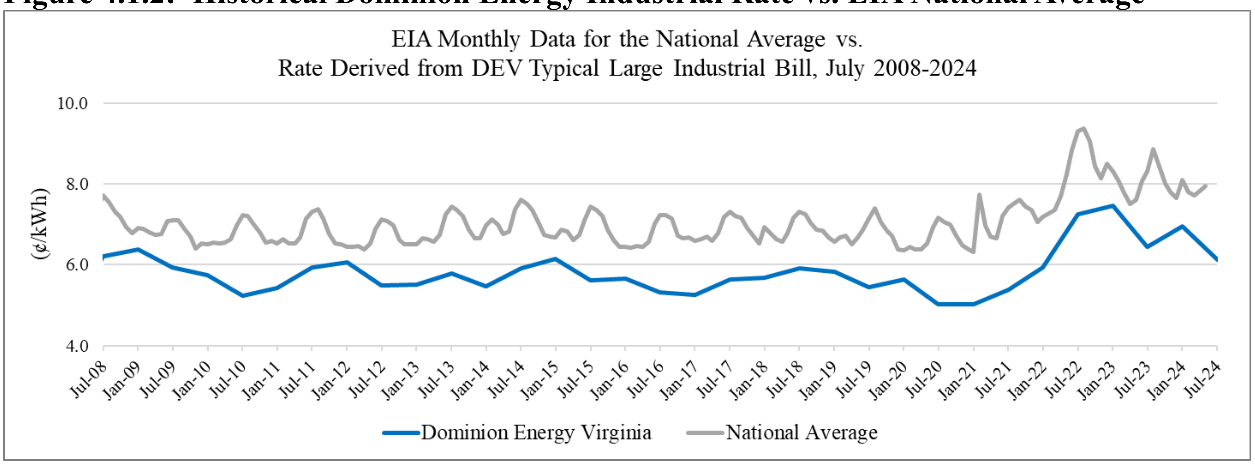
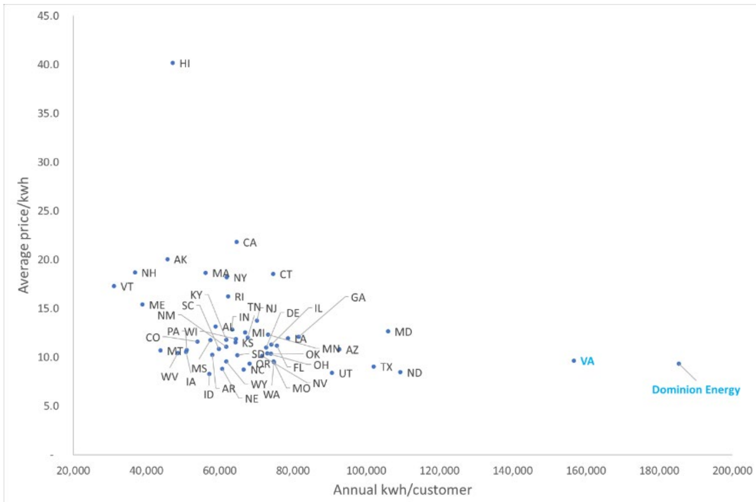


Figure 4.1.3: States by average commercial price per kWh and average consumption per commercial customer[21]



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.

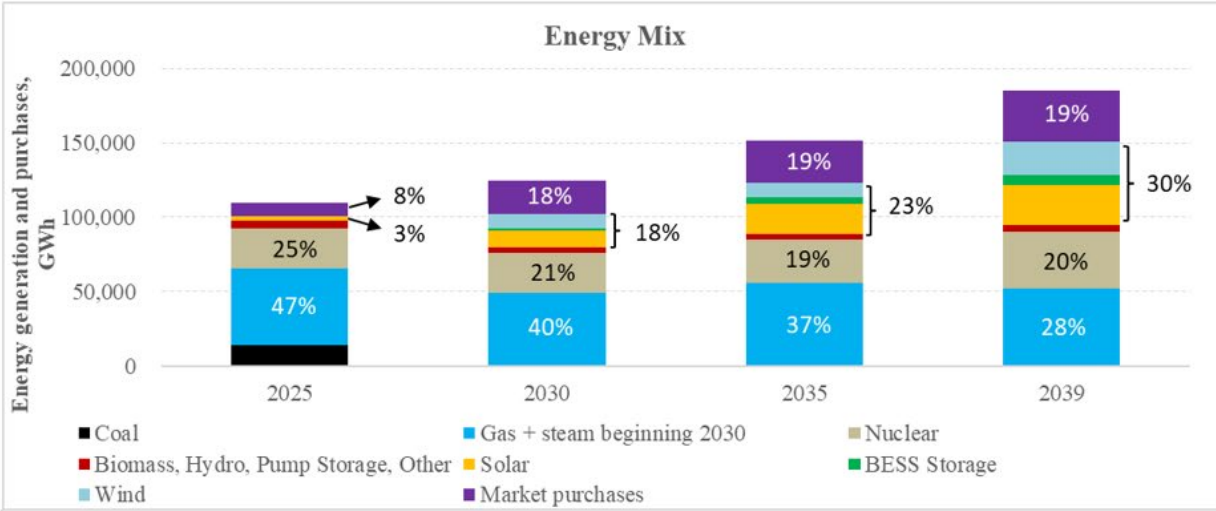
Figure 5.1.3: REC RPS Only With EPA Portfolio Build Summary

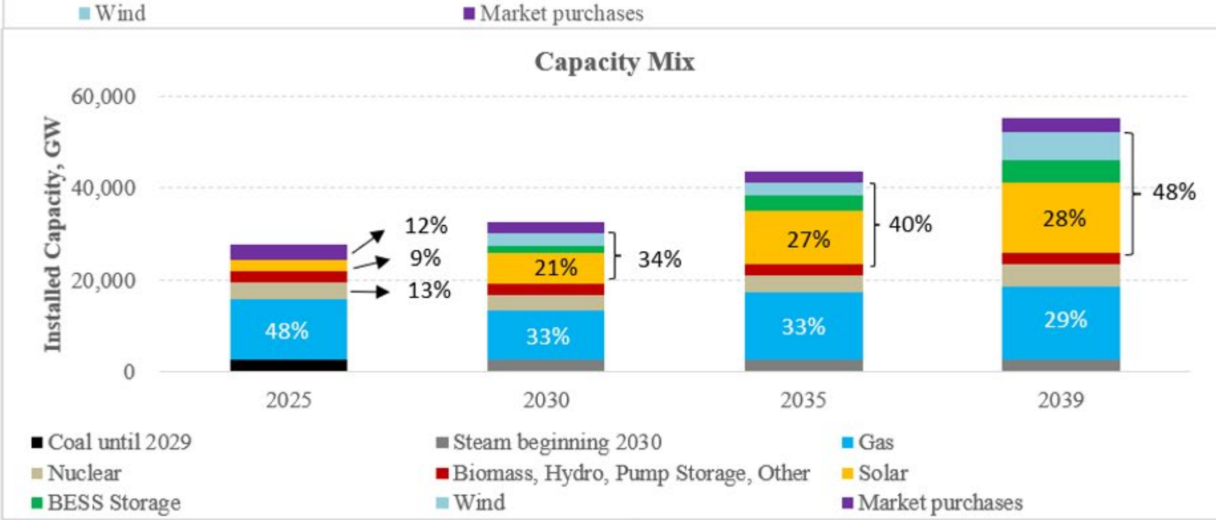
Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2025	20	-	-	-	-	-	-	2,352	-
2026	-	-	-	-	150	-	-	3,200	-
2027	206	-	4	-	92	-	-	2,300	-
2028	482	-	-	-	485	-	-	2,800	-
2029	1,020	-	-	-	350	-	-	2,700	-
2030	1,020	-	-	-	350	944	-	2,400	-
2031	1,020	-	-	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**	

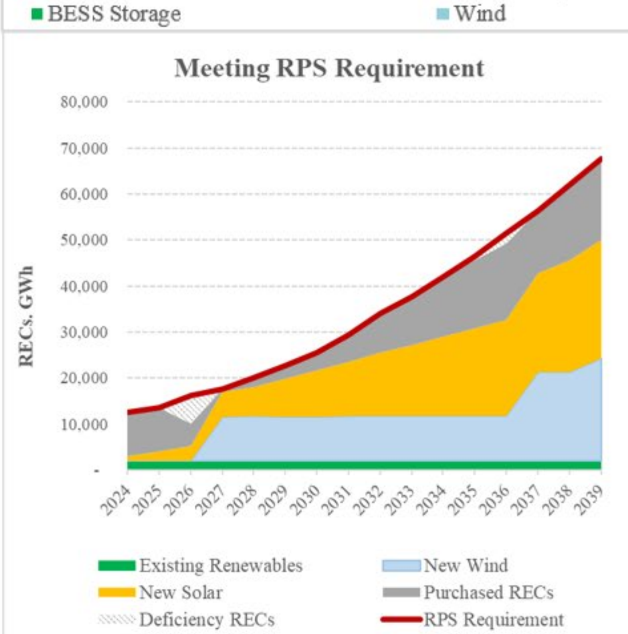
Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units

[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

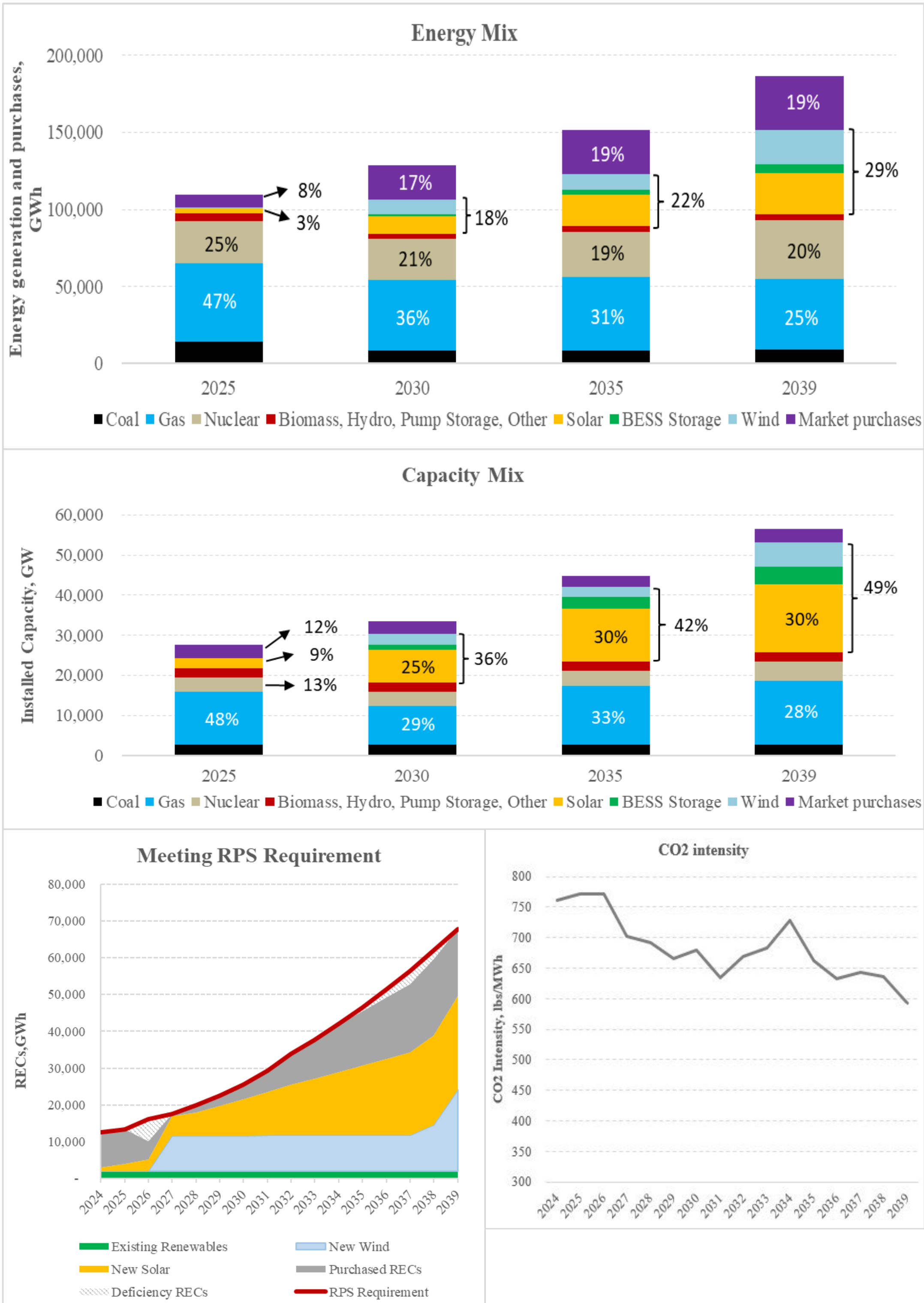
Like the REC RPS Only with EPA Portfolio, this Portfolio meets only applicable carbon regulations (before the new suite of EPA regulations was finalized) and the mandatory RPS Program requirements of the VCEA. In addition, similar to the REC RPS Only with EPA Portfolio, this Portfolio does not meet the 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

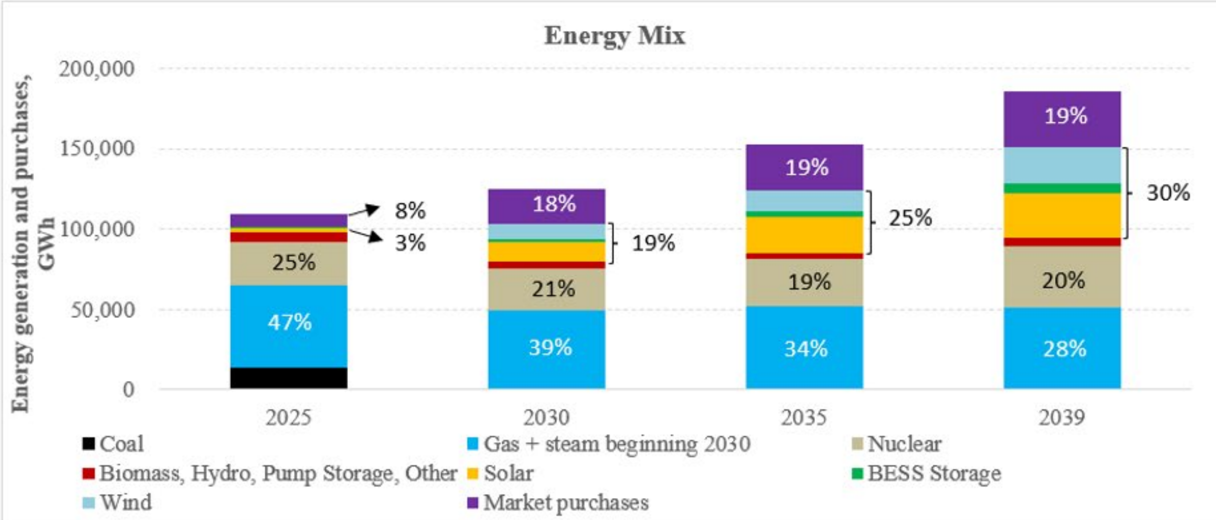
The VCEA with EPA Portfolio, which utilizes the environmental commodity price forecast, includes the significant development of solar, wind, and energy storage envisioned by the VCEA, petitioned by 2035 and built by 2039. Furthermore, this Portfolio builds additional solar and storage resources in the 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.

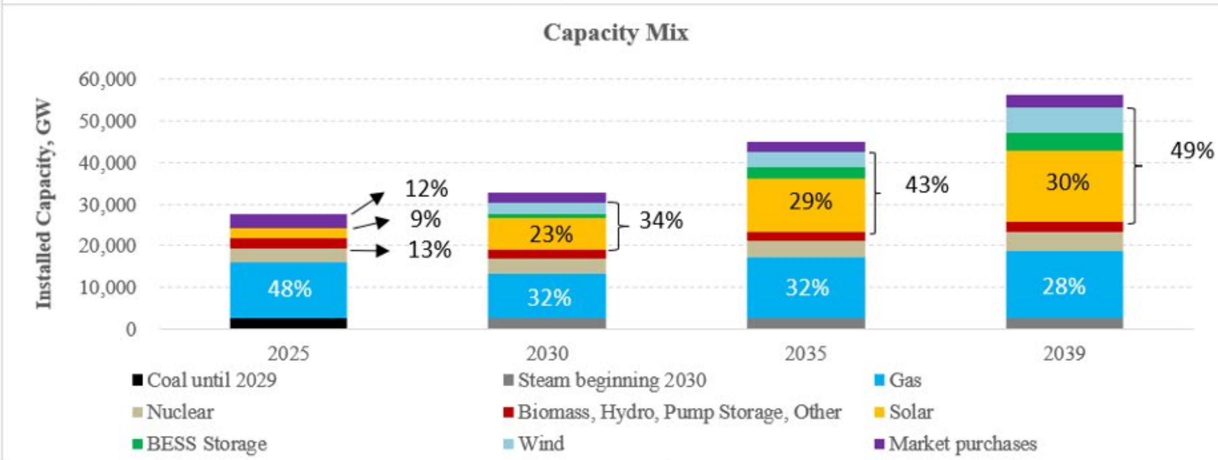
Figure 5.1.5: VCEA With EPA Build Plan Summary

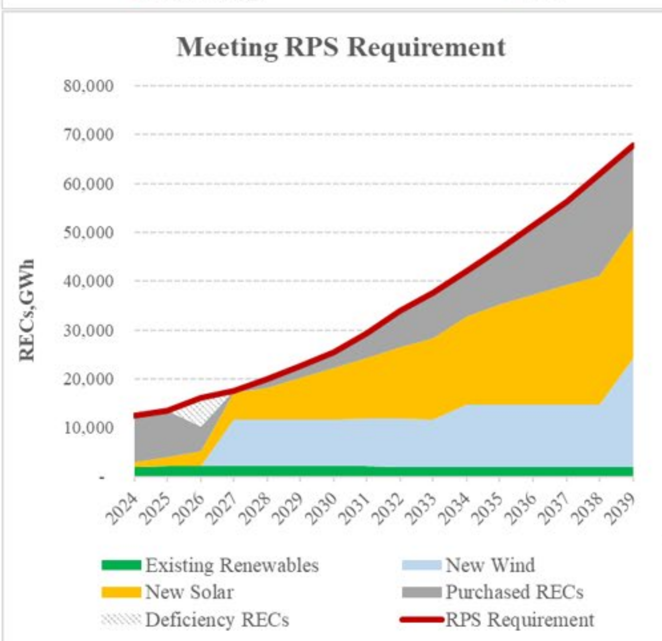
Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2025	-	-	-	-	-	-	-	2,352	-
2026	-	-	-	-	-	-	-	3,200	-
2027	-	-	-	-	-	-	-	2,300	-
2028	-	-	-	-	250	-	-	2,800	-
2029	591	429	45	-	350	-	-	2,800	-
2030	591	429	66	-	350	944	-	2,500	-
2031	552	468	75	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**	

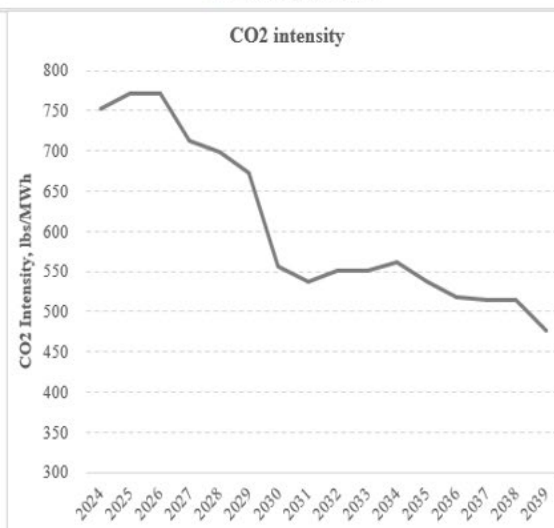
Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units

VCEA With EPA Portfolio Dashboard









VCEA Without EPA Portfolio

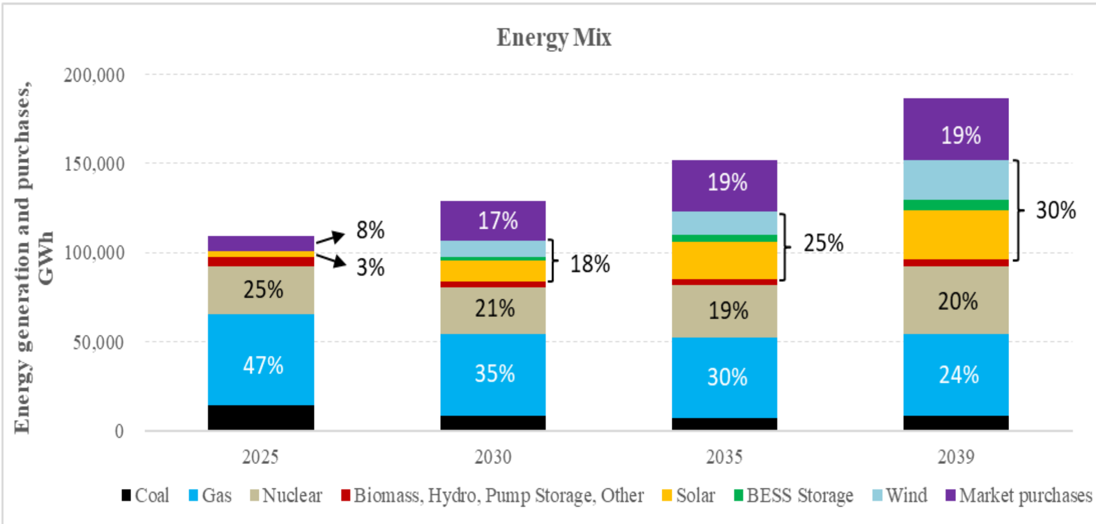
The VCEA without EPA Portfolio utilizes the standard commodity price forecast. The resource totals build for this scenario mirrors those for the VCEA with EPA Portfolio, building a total of 12.2 GW of solar, 4.1 GW of storage resources, 1.34 GWs of SMRs, 3.5 GWs of additional offshore, and 5.9 GW of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

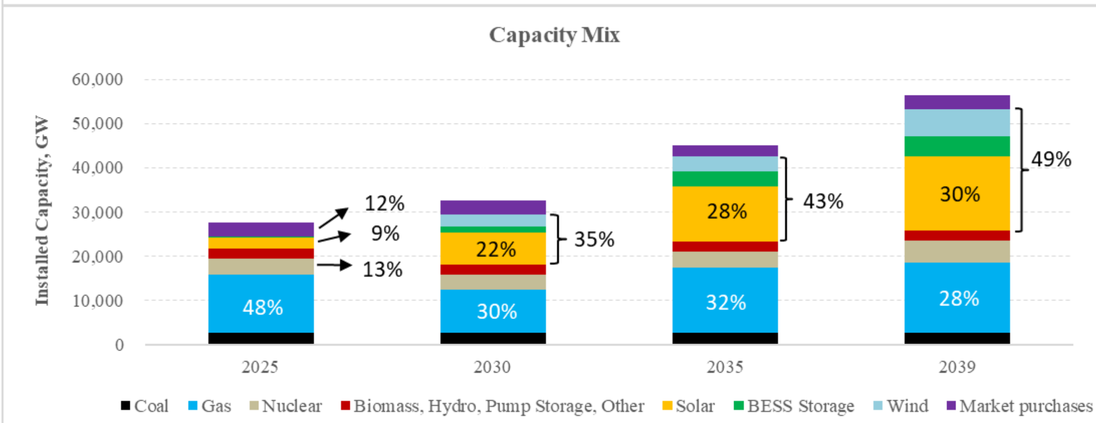
Figure 5.1.6: VCEA Without EPA

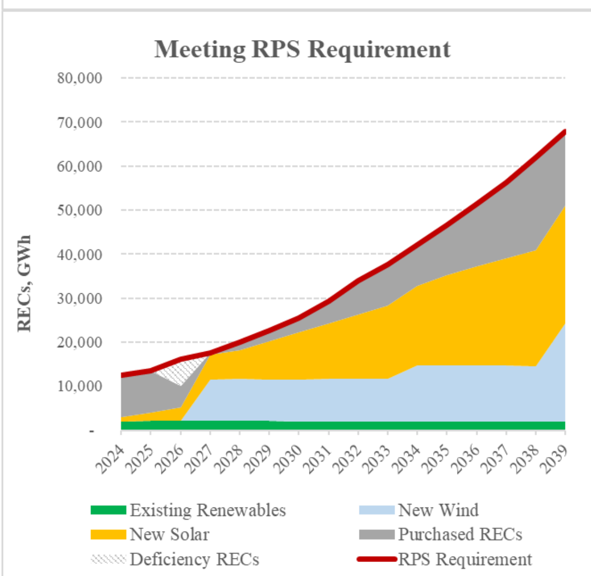
Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2025	-	-	-	-	-	-	-	2,352	-
2026	-	-	-	-	-	-	-	3,200	-
2027	-	-	-	-	-	-	-	2,300	-
2028	-	-	-	-	250	-	-	2,800	-
2029	591	429	45	-	350	-	-	2,800	-
2030	591	429	66	-	350	-	-	3,200	-
2031	552	468	75	60	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**	

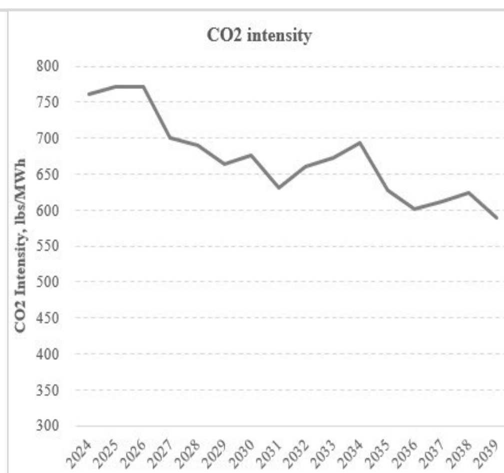
Notes: “COS” = cost of service; “PPA” = power purchase agreement; “DER” = distributed energy resources, whether Company-owned or PPA; “Wind” includes both on and offshore wind units

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

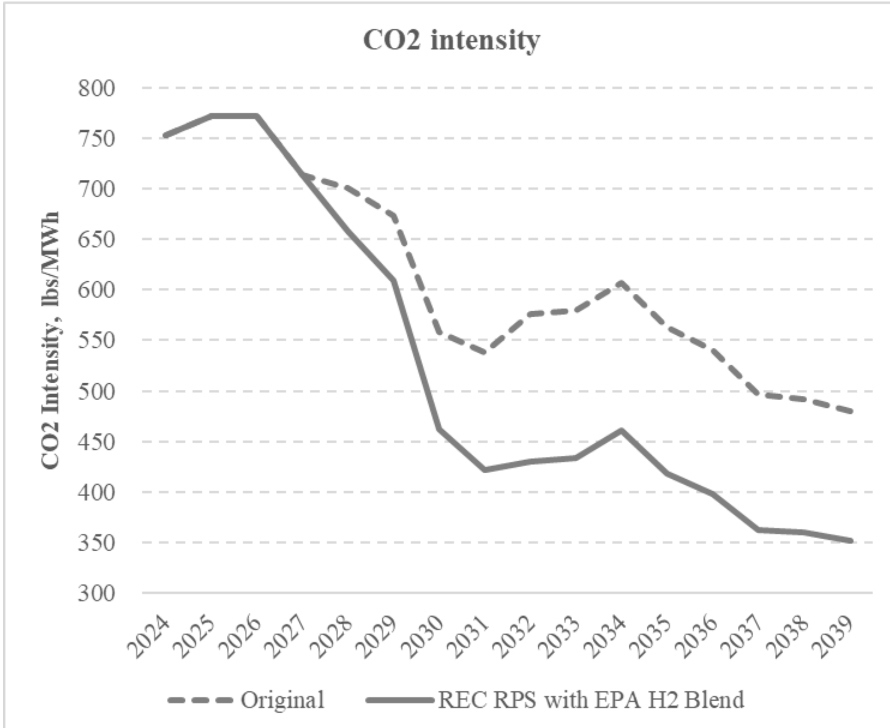


Figure 5.2.3.2: Hydrogen Blending – REC RPS Only without EPA Portfolio

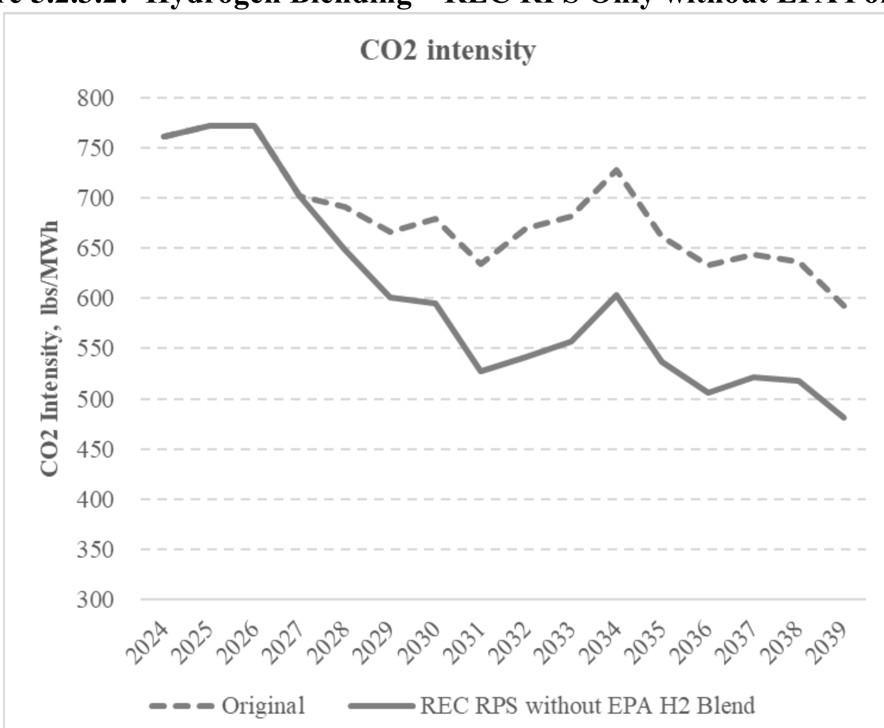


Figure 5.2.3.3: Hydrogen Blending – VCEA with EPA Portfolio

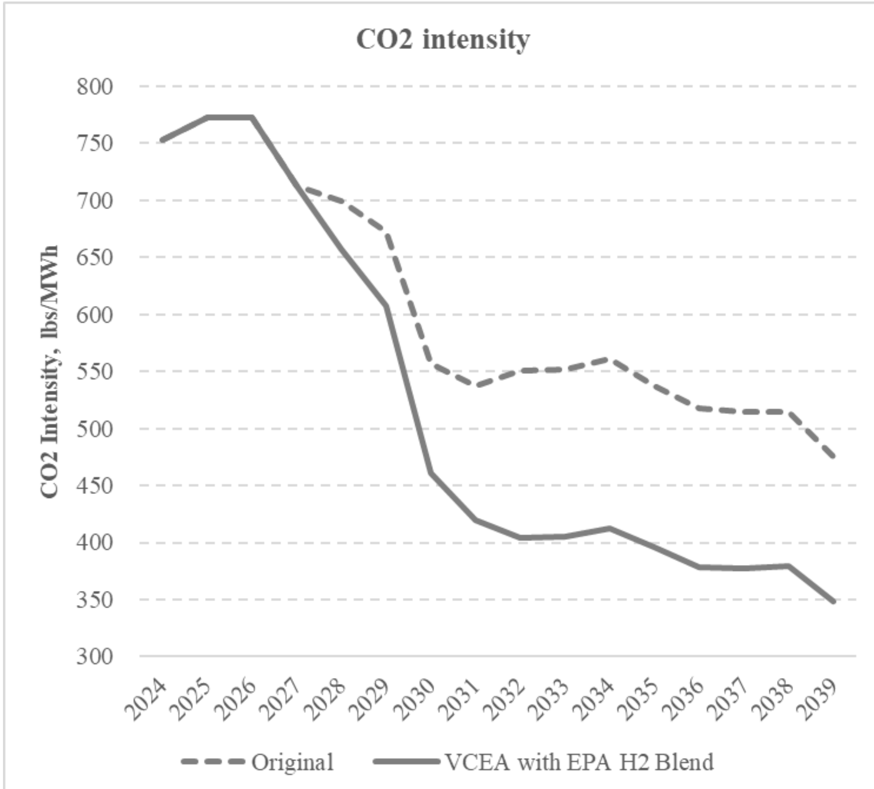
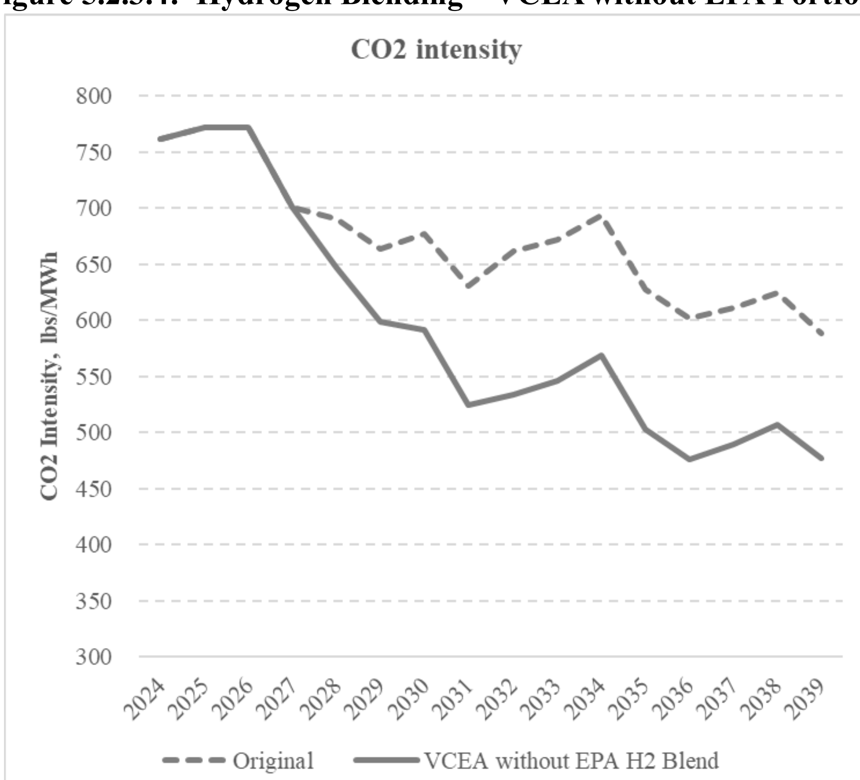


Figure 5.2.3.4: Hydrogen Blending – VCEA without EPA Portfolio



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.

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.

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.

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**	

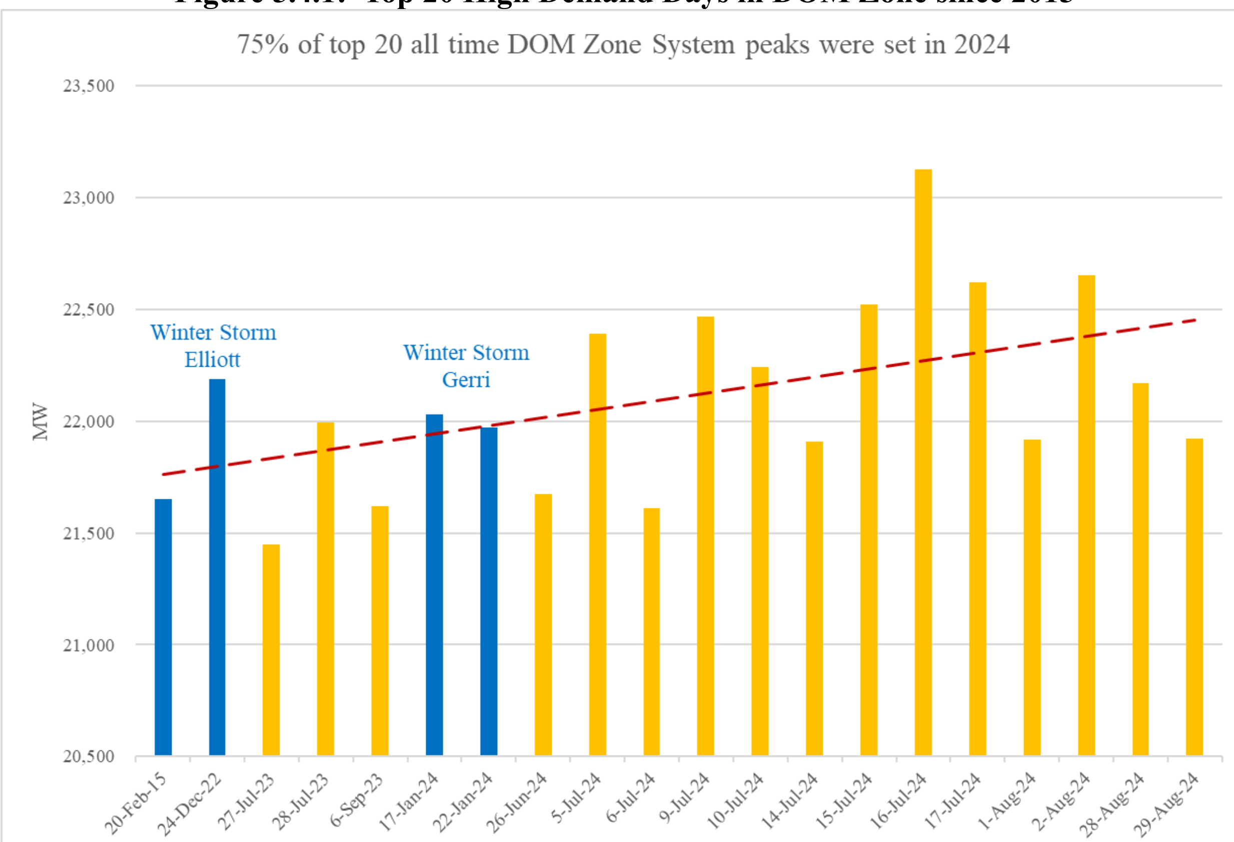
Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units

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.

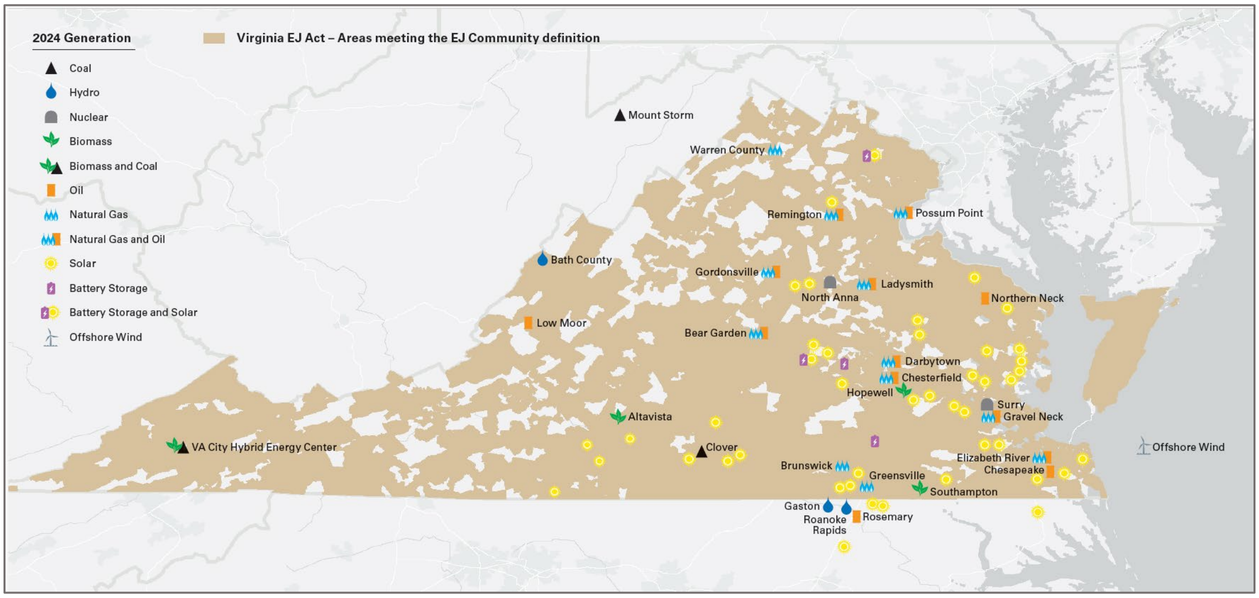
Information regarding the Company's comparison of the environmental justice consequences of constructing and/or operating different types of power generation resources contemplated by 2024 IRP modeling exercises is provided in Appendix 6A.

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.