



**Dominion
Energy[®]**

**Virginia Electric and Power
Company's 2025 Update to the
2024 Integrated Resource Plan**

Before the Virginia State
Corporation Commission and
North Carolina Utilities
Commission

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

Filed: October 15, 2025

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

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¹ Filed in Virginia only.

² Filed in North Carolina only.

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

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

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

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

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

- Confirmation of significant demand growth projections for the Dominion Energy delivery Zone of PJM (“DOM Zone”), both within Dominion Energy’s service territory and, more significantly, the remainder of DOM Zone, consistent with the 2024 IRP load forecast;
- Updated planning portfolios required to meet forecasted demand and the need for adequate and reliable capacity and energy resources, including during severe weather events, that are incrementally more robust and diverse than the 2024 IRP portfolios;
- A shift to a 20-year resource planning timeframe, consistent with PJM’s new planning horizon; and
- The potential impact of evolving market conditions and changing federal environmental and fiscal policies on the Company’s resource planning.

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

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

PJM holds annual capacity auctions to attempt to ensure that supply resources are adequate to meet demand at peak times (typically when it is very hot or very cold), including a safety reserve margin. The most recent capacity auction in July 2025 yielded the second-highest capacity price ever for the DOM Zone, which has the highest forecasted load growth of any area within PJM. Factors driving higher capacity values for a given area include high demand, fewer resources to meet the demand and a restricted ability to import power. The DOM Zone cleared just over \$329/MW-day for the 2026/2027 Delivery Year¹. The 2026/2027 capacity auction results signal continued resource adequacy concerns for not only the DOM Zone but the entire PJM footprint.

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

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

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

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

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

² Va. Code § 56-599 D.

The 2025 IRP Update

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

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

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

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

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

Chapter 1. Commitment to Reliability

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

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

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

Dominion Energy also owns and operates a portion of the transmission system (also known as the bulk power system) that moves large amounts of electricity over long distances. This transmission system is responsible for providing service (i) for redelivery to the Company's retail customers in Virginia and North Carolina; (ii) to Old Dominion Electric Cooperative ("ODEC"), Northern Virginia Electric Cooperative ("NOVEC"), Central Virginia Electric Cooperative, and Virginia Municipal Electric Association for redelivery to their retail customers in Virginia; and, (iii) to North Carolina Electric Membership Corporation and North Carolina Eastern Municipal Power Agency for redelivery to their customers in North Carolina (collectively, this region is referred to as the DOM Zone and encompasses the DOM LSE as well as the territories of other LSEs). Dominion Energy owns approximately 6,800 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV in Virginia, North Carolina, and West Virginia. The DOM Zone is

part of PJM,⁴ which encompasses all or part of 13 states, as well as the larger Eastern Interconnection transmission grid, meaning the transmission system is interconnected, directly or indirectly, with other transmission systems in the United States and Canada between the Rocky Mountains and the Atlantic Coast, except for Quebec and most of Texas. The transmission systems in the Eastern Interconnection are dependent on each other for moving bulk power through the transmission system and for reliability support. Accordingly, as a transmission owner, Dominion Energy is not only responsible for reliable service to its own transmission customers, but also for the integrity of the Eastern Interconnect as a whole. Additionally, Dominion Energy owns approximately 60,600 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia and North Carolina. Distribution lines deliver power from substations to individual neighborhoods, homes, and businesses.

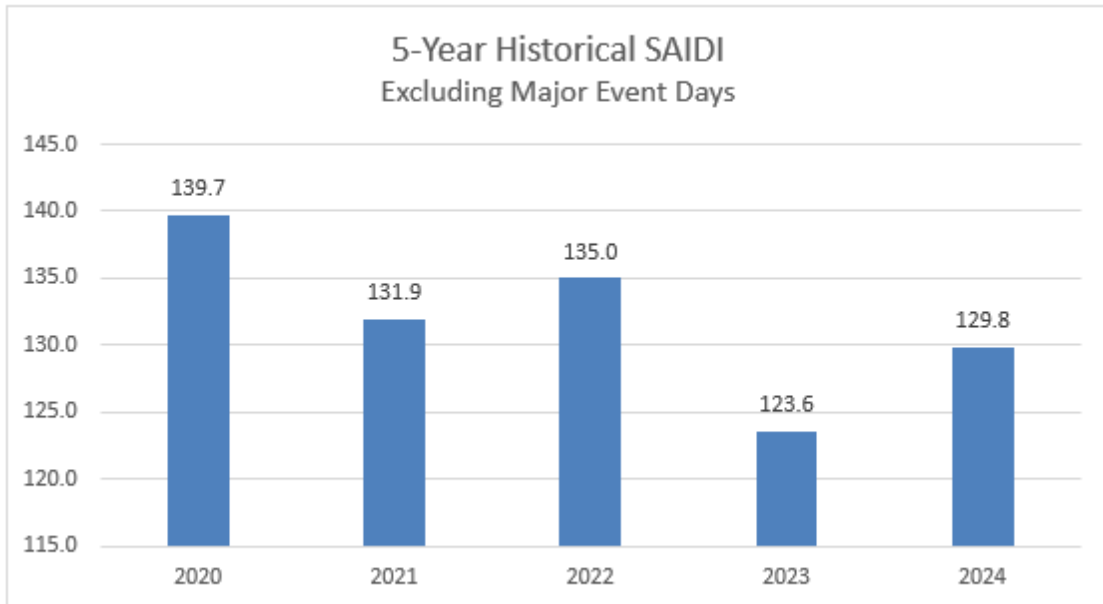
Dominion Energy must plan and operate its three functional aspects to ensure reliability for all customers. For power generation, reliability requires a sufficient number of generation resources and resource diversity to avoid over-reliance on any one energy source, along with dependable fuel supplies.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

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

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

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

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



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

Chapter 2. Current Challenges to Reliability

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

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

2.1 The Load Forecast

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

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

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

The entire PJM region is experiencing unprecedented load growth, and the DOM Zone continues to be one of the fastest growing zones in PJM. On January 23, 2025, the DOM Zone set a new all-time record peak of 24,678 MW. Figure 2.1.1 presents the 2025 PJM Load Forecast for coincident peak⁵ for the DOM Zone. Overall, the 20-year compound annual growth rate (“CAGR”)⁶ for the DOM Zone is 4.1%.

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

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

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

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

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

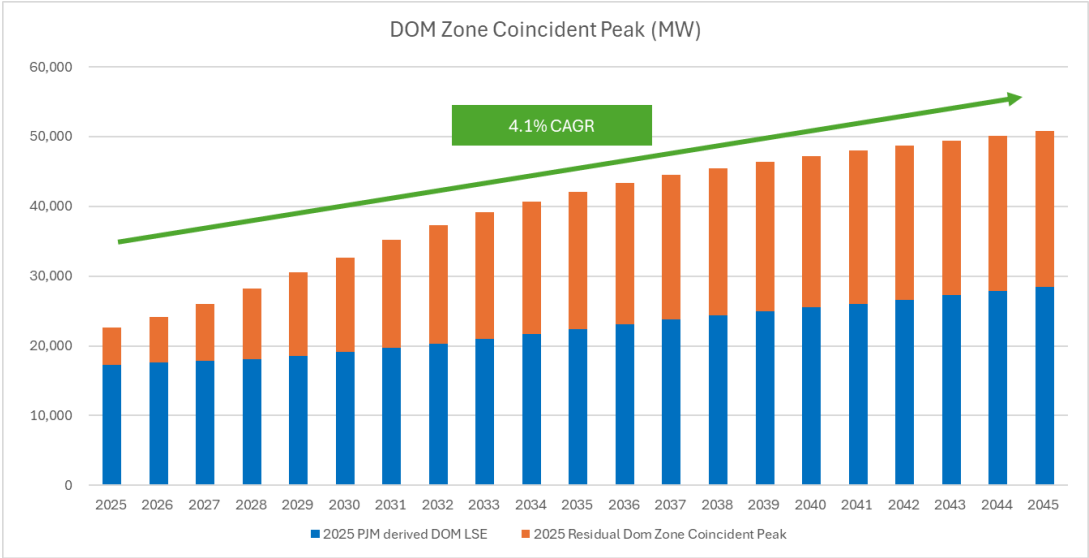


Figure 2.1.2 presents the 2025 PJM Load Forecast for energy for the DOM Zone. Overall, the 20-year CAGR for the DOM Zone is 5.3%; this is comprised of the DOM LSE, which is forecast to grow at a 3.5% CAGR, and the Residual DOM Zone portion, which is forecasted to experience an 8.5% CAGR. Like the load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

Figure 2.1.2: 2025 PJM Load Forecast for Annual Energy

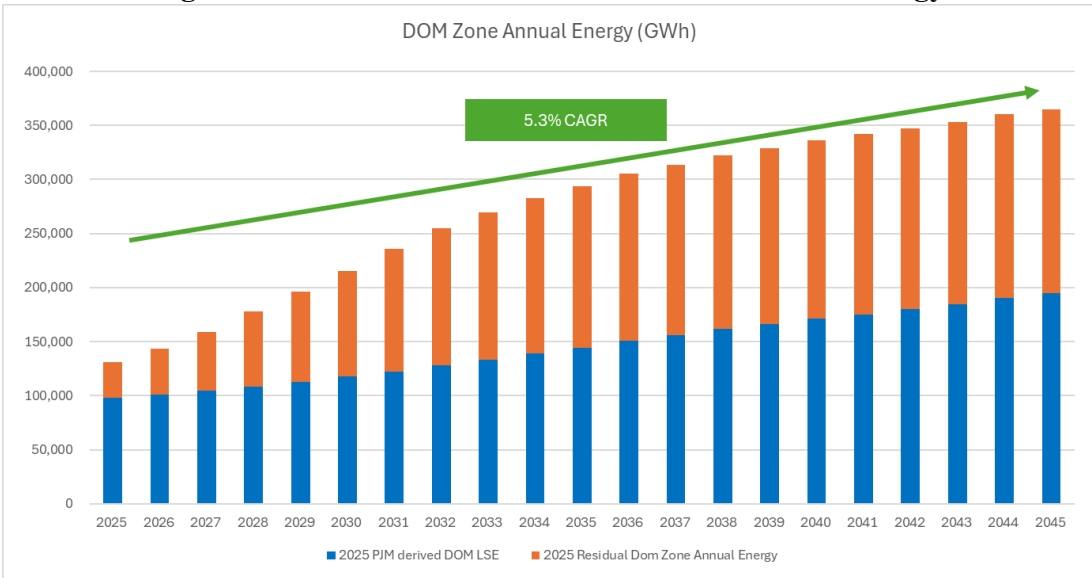


Figure 2.1.3 presents the year-over-year changes in PJM’s DOM Zone load forecasts. PJM’s 2025 Load Forecast for the DOM Zone increased in the outer years for the fourth year in a row relative to the prior year’s forecast. Increases in the data center load forecast continue to be a key driver for the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

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

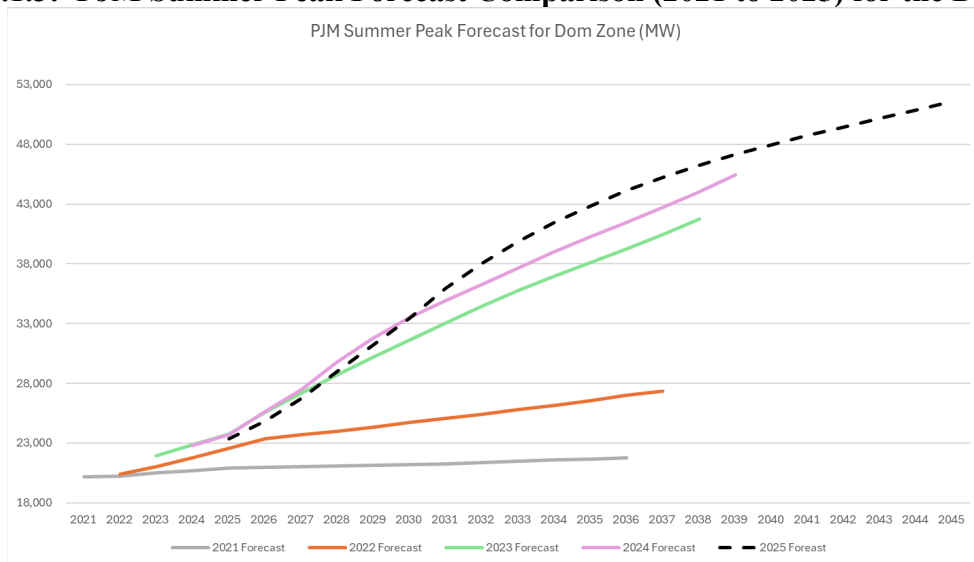
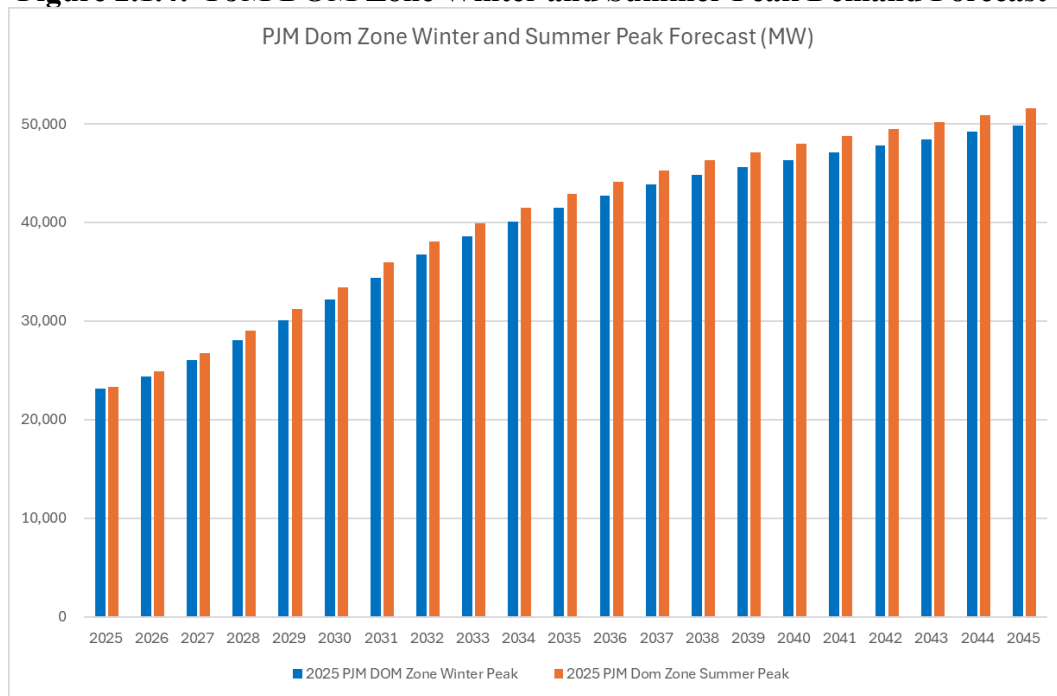


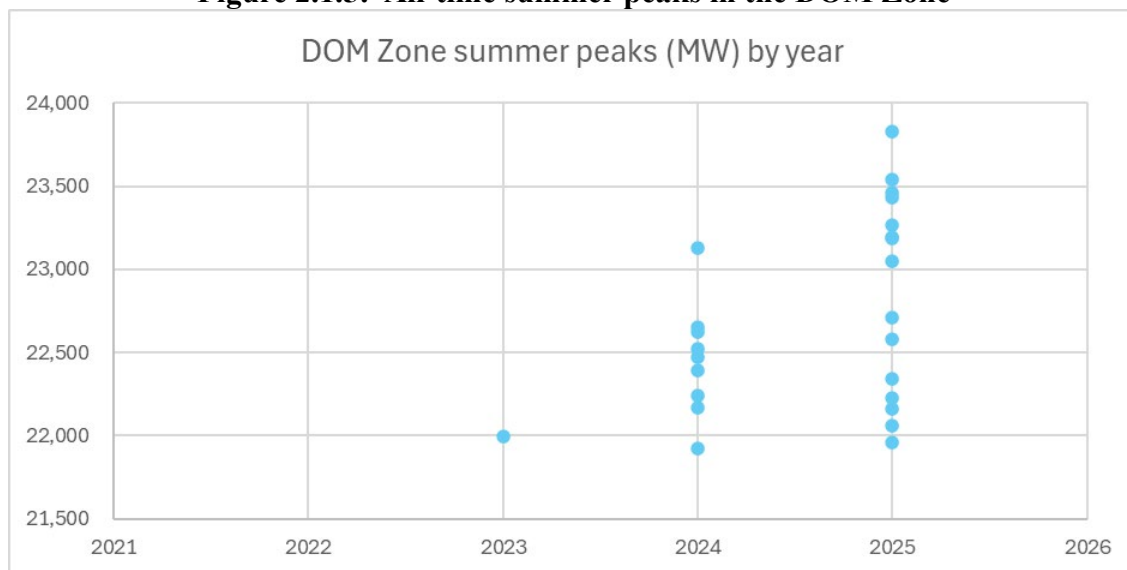
Figure 2.1.4 shows the PJM DOM Zone forecasted non-coincident peaks split out by winter and summer. Over the 20-year forecast horizon, winter and summer peaks are projected to grow by 3.9% and 4.0%, respectively, on a compound annual basis. Forecasted peaks assume normal weather, meaning that extreme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

Figure 2.1.4: PJM DOM Zone Winter and Summer Peak Demand Forecast⁷



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

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



⁷ <https://pjm.com/-/media/library/reports-notice/load-forecast/2024-load-report.ashx>.

PJM Derived Load Forecast for the DOM LSE

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

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

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

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

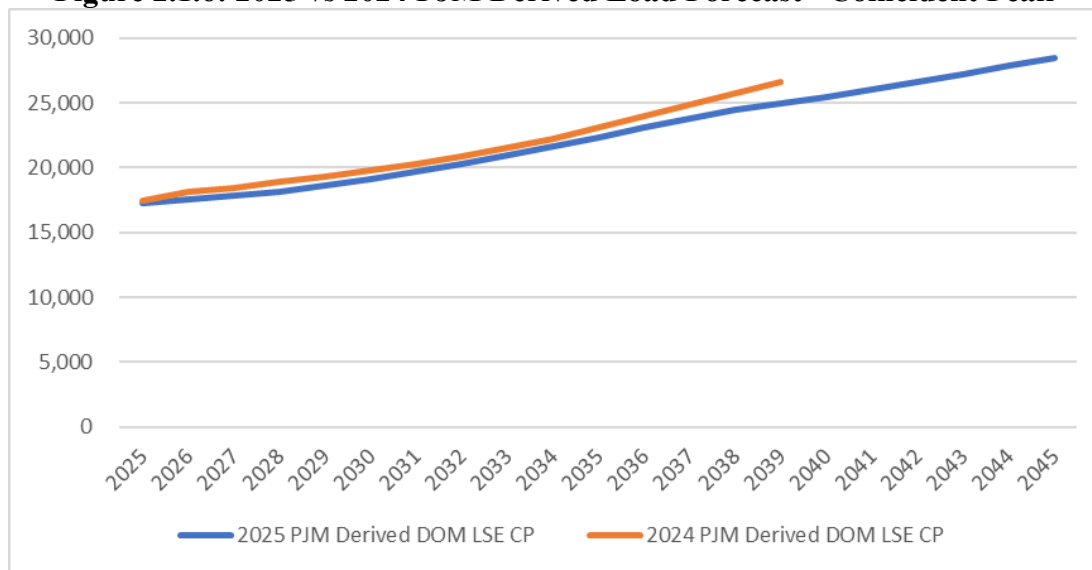
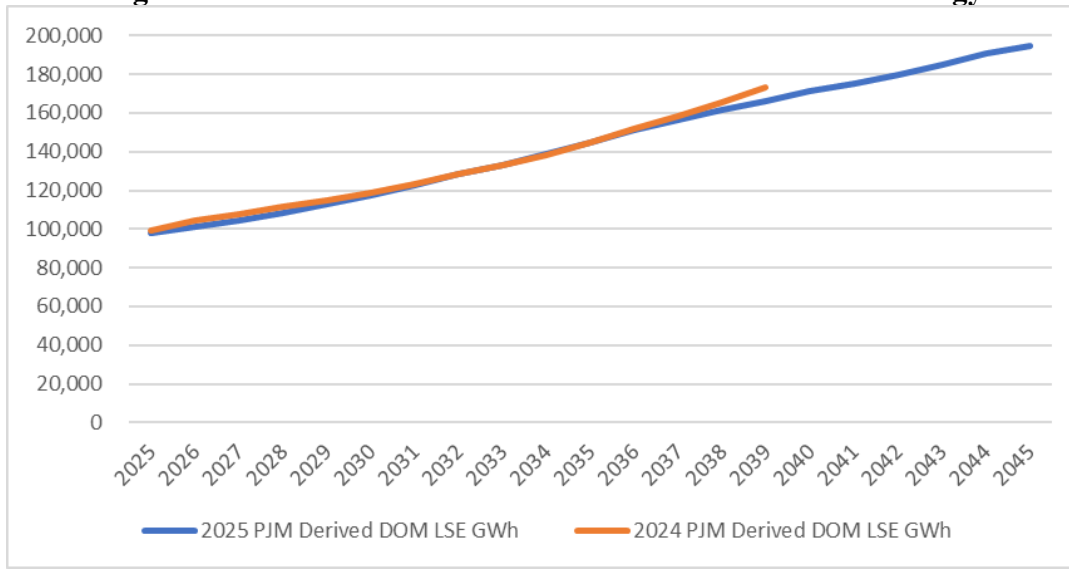


Figure 2.1.7: 2025 vs 2024 PJM Derived Load Forecast – Energy



Company Load Forecast

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

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

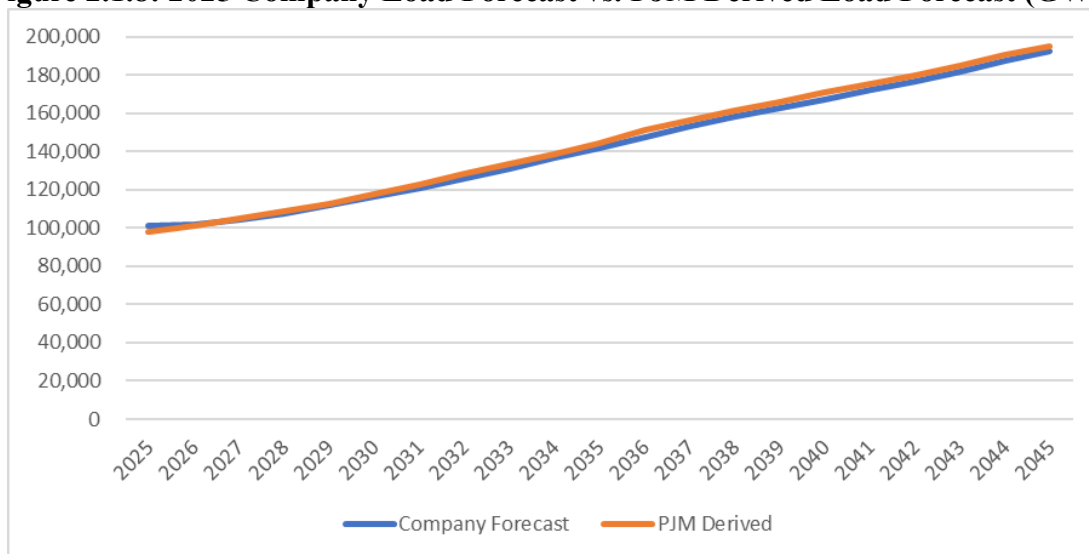


Figure 2.1.9 below presents the 2025 Company Load Forecast NCP and annual energy.

Figure 2.1.9: 2025 Company Load Forecast

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

Electric Vehicle Forecast

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

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

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

Energy Efficiency Adjustment to DOM LSE Load Forecast

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

Figures 2.1.11 and 2.1.12 identify the specific EE energy and coincidental capacity adjustments to the load forecasts used in this 2025 IRP Update, respectively. Values shown are at the utility generator and adjusted for line losses. In the values below, the EE adjustment includes savings generated from the Company’s voltage optimization (“VO”) program. These energy savings are excluded from the EE adjustment used in the PJM Derived Load Forecast, since the Company

provided the VO savings as part of a Large Load Adjustment to PJM. The VO savings are therefore embedded in the PJM DOM Zone forecast.

Figure 2.1.11: EE Energy Forecast Adjustment (GWh)

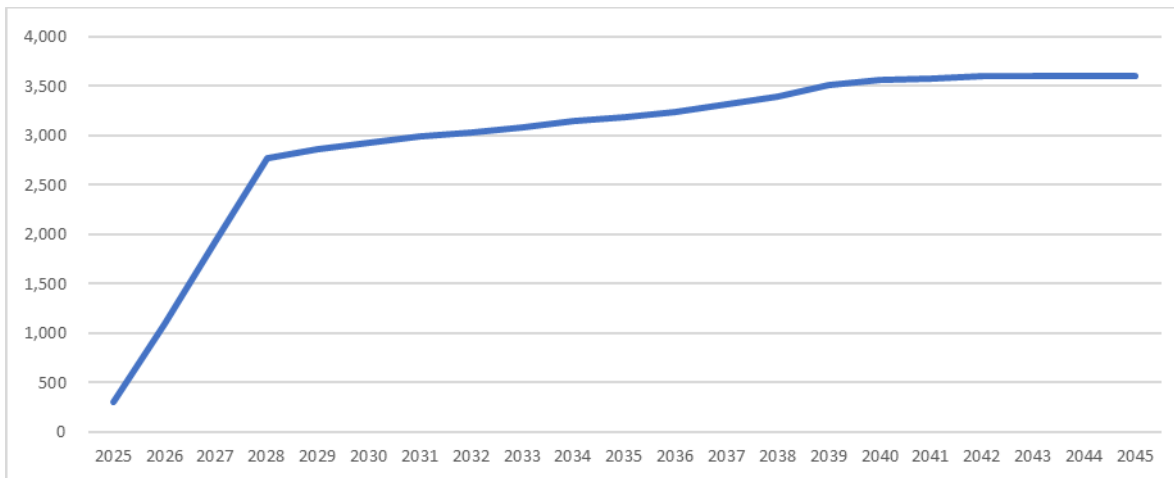
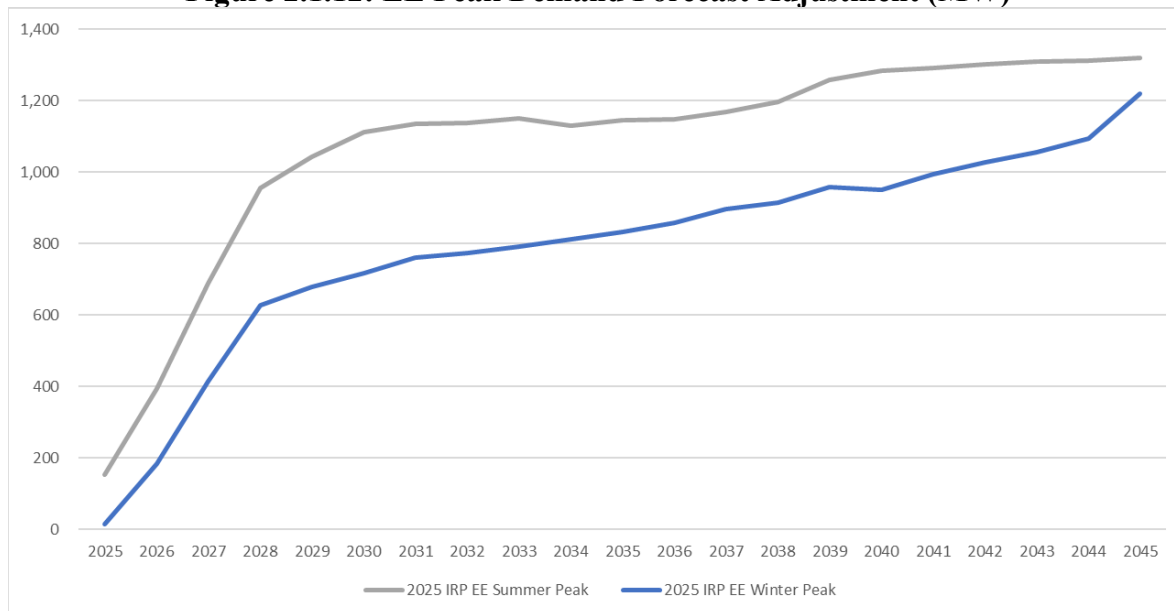


Figure 2.1.12: EE Peak Demand Forecast Adjustment (MW)



Retail Choice Adjustment to DOM LSE Load Forecast

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

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

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

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

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

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

Data center load in the DOM Zone and DOM LSE

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

The Company has connected six new data center campuses in 2025¹⁰ as of October 1st, with an ultimate capacity of 456 MW. The Company expects to connect two additional data center campuses by the end of the year, for a total of 8 new data center campus connects, with an ultimate capacity of 561 MW in 2025. Given the demand from data centers locating in the DOM Zone, the Company is forecasting significant growth into the future.

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

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

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

Figure 2.1.14 illustrates customer contracts executed as of July 2025.¹¹ These contracts are broken into (i) Engineering Letters of Authorization (“ELOA”), (ii) Construction Letters of Authorization (“CLOA”), and (iii) Electric Service Agreements (“ESA”). As a customer moves from (i) to (iii), the financial commitment and obligation by the customer increases. The graph shows the continued growth from executed ESAs through 2038 and support for growth beyond that from the projects currently under construction (CLOAs). See Appendix 2A of the 2024 IRP for additional details about the three types of contracts.

Figure 2.1.14: Customer Contracts Executed, as of July 2025

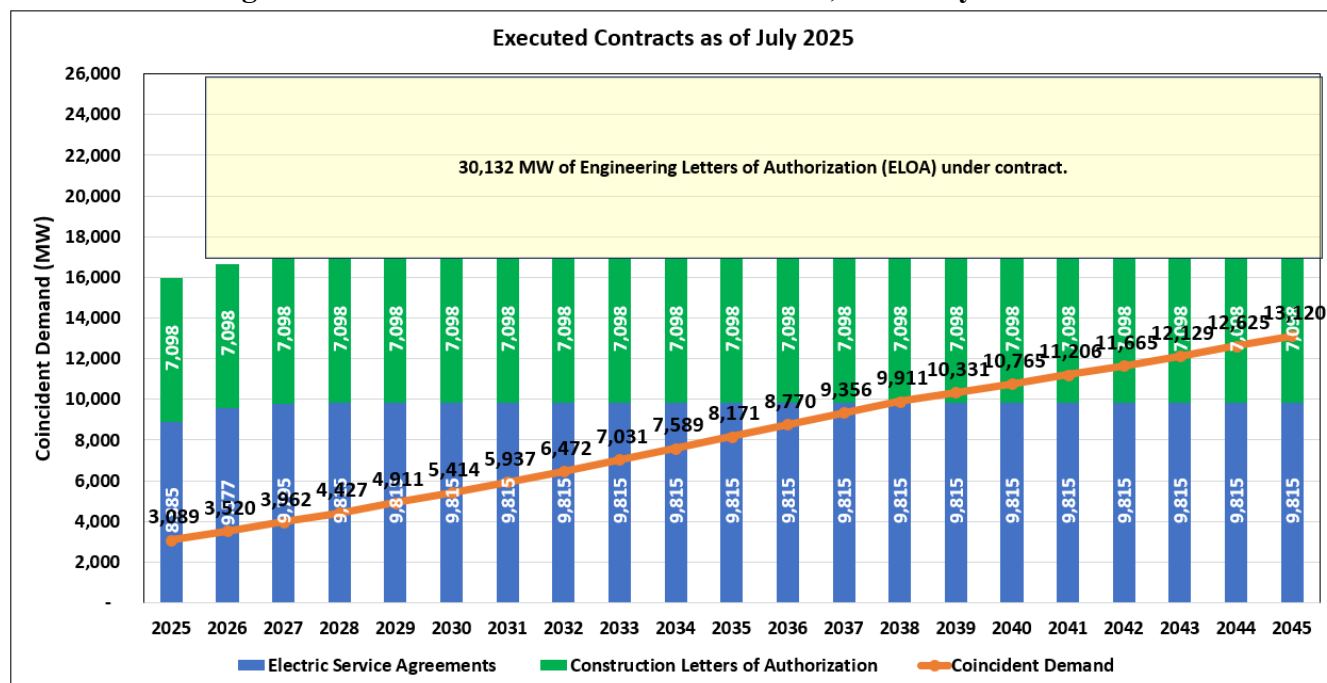


Figure 2.1.15 illustrates the significant growth in contracts from 2023 to 2025, as well as the movement of projects through the three stages of contracts. As of July 31, 2025, the Company has 16,913 MW of requested capacity under firm contracts through executed ESAs or CLOAs. The Company is currently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

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

Figure 2.1.15: Data Center Contract Growth

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

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

2.2 Updates to the PJM Market Affect the Planning Environment

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

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

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

2.2.1 Capacity Planning

As a member of PJM, Dominion Energy is a signatory to PJM’s Reliability Assurance Agreement (“RAA”), which obligates the Company to purchase sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone using its annual load forecast and reserve margin¹³ guidelines as inputs. PJM then conducts a capacity auction process for meeting these input requirements up to three years into the future. This auction process includes the Base Residual Auction (“BRA”) for the RPM as well as subsequent incremental auctions that are held to allow market sellers and PJM to adjust positions for changes such as load forecasts, generator retirements, Effective Load Carrying Capability (“ELCC”), construction delays, or outage assumptions. This auction process determines the clearing reserve margin and the capacity price for each zone for the delivery year that is three years in the future.

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

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

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

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

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

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

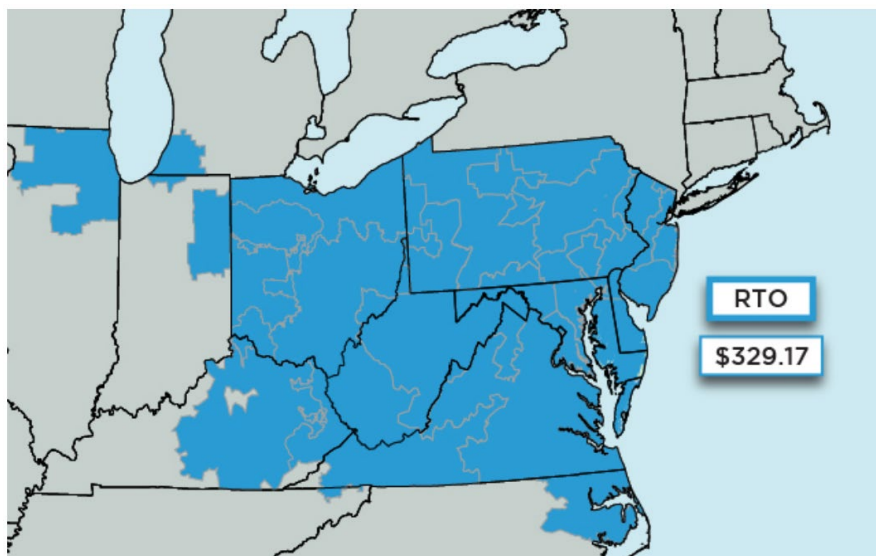
¹⁴ EFORD is a measure of the probability that the generating unit will not be available due to a forced outage or forced derating when there is a demand on the unit to generate.

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

2.2.2 The 2026/2027 PJM BRA Results

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

Figure 2.2.2.1: PJM 2026/2027 RPM Capacity Auction Results - Capacity Prices¹⁶



¹⁵ See footnote 1.

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

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

2.2.3 Resource Adequacy and Market Functioning Challenges in PJM Capacity Market

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

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

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

The entire PJM region is experiencing unprecedented load growth, which results in challenges in securing capacity resources needed to meet that growing demand. This challenge is exacerbated by (i) significant loss of dispatchable generation capacity throughout PJM due to premature retirements, and (ii) new generation in the PJM interconnection queue being dominated by intermittent resources.¹⁷ A series of PJM reports¹⁸ analyzed the impacts of integration of renewable resources and concluded maintaining reliability as dispatchable generators retire becomes more challenging. In that regard, reserves are declining, which means that generating capacity available to PJM for dispatch exceeds projected demand by a smaller margin than it used to, reducing the

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

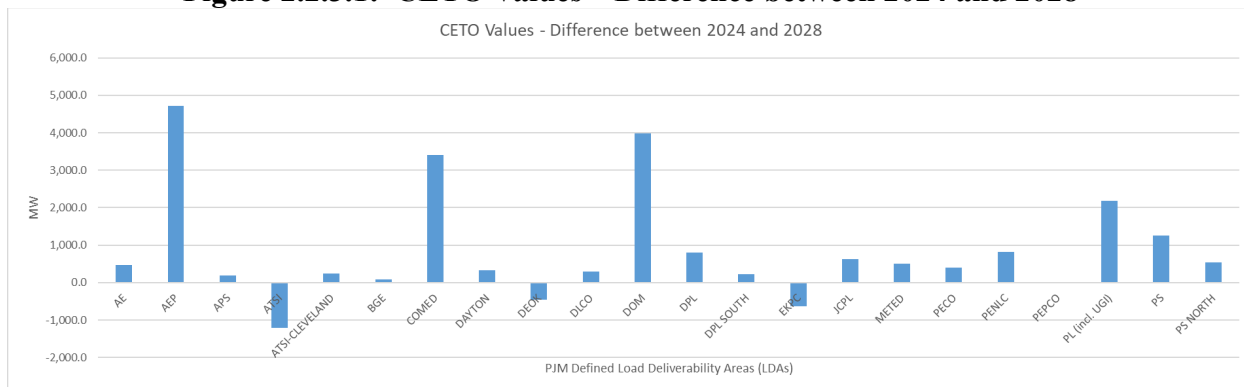
¹⁸ See PJM Interconnection, L.L.C., *Energy Transition in PJM: Frameworks for Analysis* (Dec. 15, 2021), and the *Addendum* (Mar. 3, 2022); PJM Interconnection, L.L.C., *Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid* (Oct. 28, 2022), and the *Addendum* (Nov. 10, 2022); PJM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

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

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

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

Figure 2.2.3.1: CETO Values – Difference between 2024 and 2028



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

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

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

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

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

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

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

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

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

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

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

2.3 Transmission Considerations

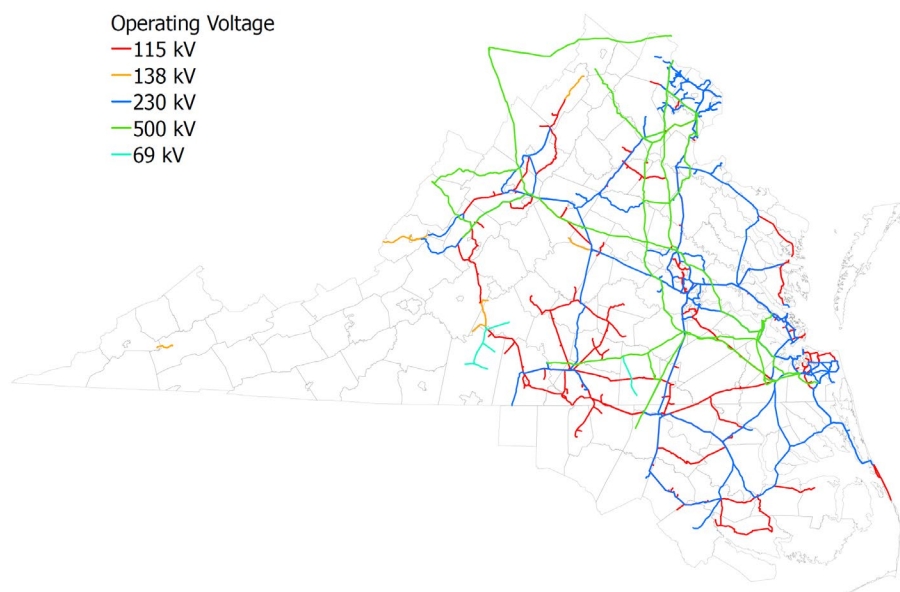
2.3.1 Transmission Planning

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

2.3.2 Existing and Future Transmission Facilities

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

Figure 2.3.2.1: Dominion Energy's Existing Transmission Lines $\geq$ 69kV



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

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

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

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

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

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

2.3.3 Transmission System Reliability Analyses

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

The Company performed the following analyses for this 2025 IRP Update: (1) an import limit study for the DOM Zone; (2) an inertial and frequency response study to evaluate the increasing

penetration of inverter-based resources; (3) a short circuit analysis to evaluate the system's ability to quickly recover from faults; and (4) a review of system restoration and black start capabilities. Details on the methodologies used for these analyses and their results are provided in Appendix 2D. The analyses continue to show that traditional synchronous generation is needed to help maintain system reliability.

2.4 Distribution Considerations

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

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

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

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

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

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

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

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

2.5 Generation Considerations

2.5.1 Expanding Generation Resource Adequacy

Historically, the Company’s transmission planning considers the entire DOM Zone, whereas the Company’s generation planning focuses primarily on the DOM LSE. The tightening supply of energy and capacity and increasing demand, however, suggest that the Company is beginning to

compete more often with other LSEs for available energy in the PJM market, especially during peak demand hours and/or severe weather events. As a result, the Company is more closely considering the energy and capacity needs of the entire DOM Zone when planning for generation as it is far and away the largest power generator in DOM Zone and all LSEs within the DOM Zone face the same constraints on their ability to rely on market purchases to maintain reliability and affordability.

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

2.5.2 Development Challenges

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

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

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

Tariffs and Foreign Entity of Concern (“FEOC”) requirements are also changing the development and construction of new power generation projects, particularly in solar and energy storage technologies. These measures restrict access to critical materials and components—such as solar panels, inverters, and battery minerals—sourced from certain foreign suppliers, increasing costs and limiting availability. As developers navigate these trade and compliance barriers, project

timelines are extended and procurement strategies must be restructured, adding uncertainty and complexity to an already strained supply chain environment.

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

Chapter 3. Producing Cleaner Energy While Ensuring Reliability

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

3.1 Supply-Side Generating Resources

3.1.1 System Resources

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

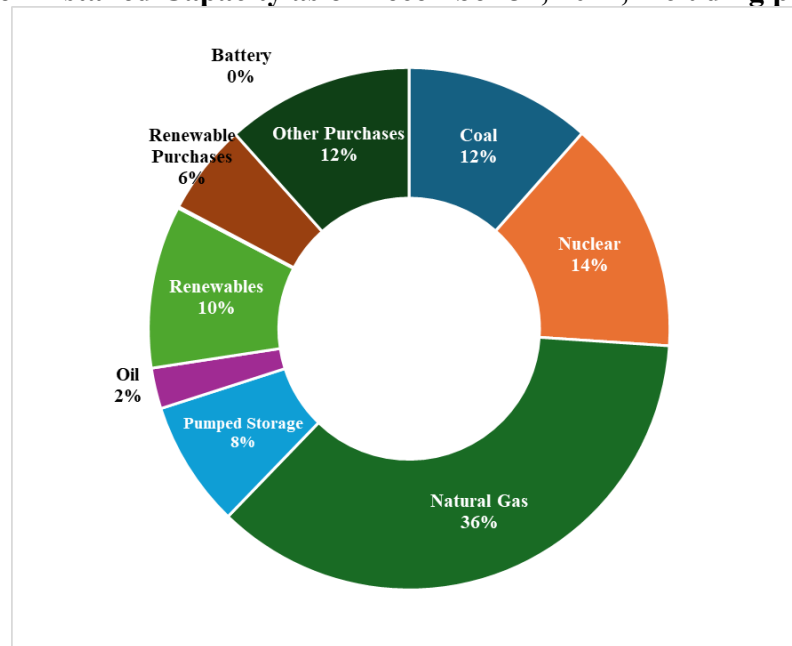
Figure 3.1.1.1: 2024 Capacity Resource Mix by Unit Type

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

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

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

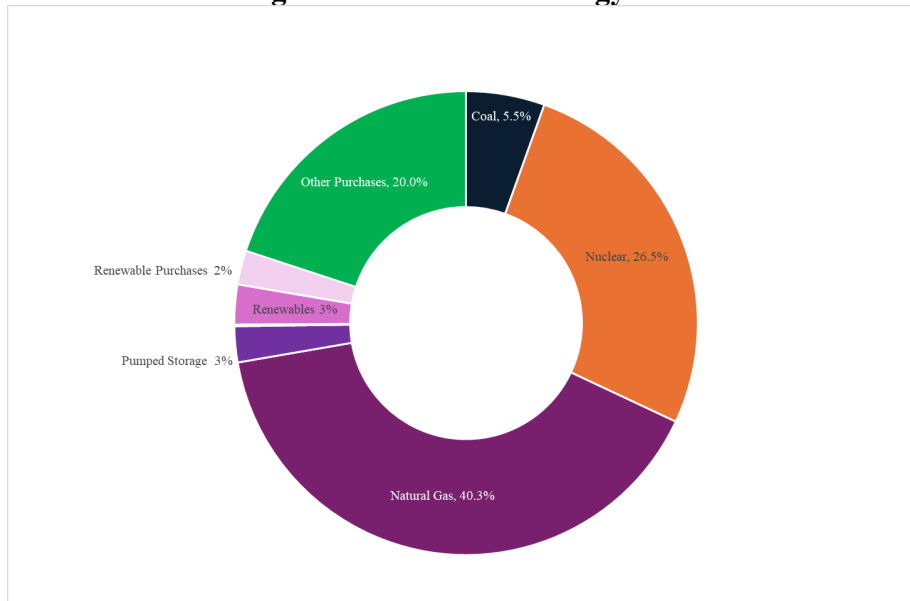
Figure 3.1.1.2: Capacity Mix
(Summer Installed Capacity as of December 31, 2024, including purchases)



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

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

Figure 3.1.1.3: 2024 Energy Mix



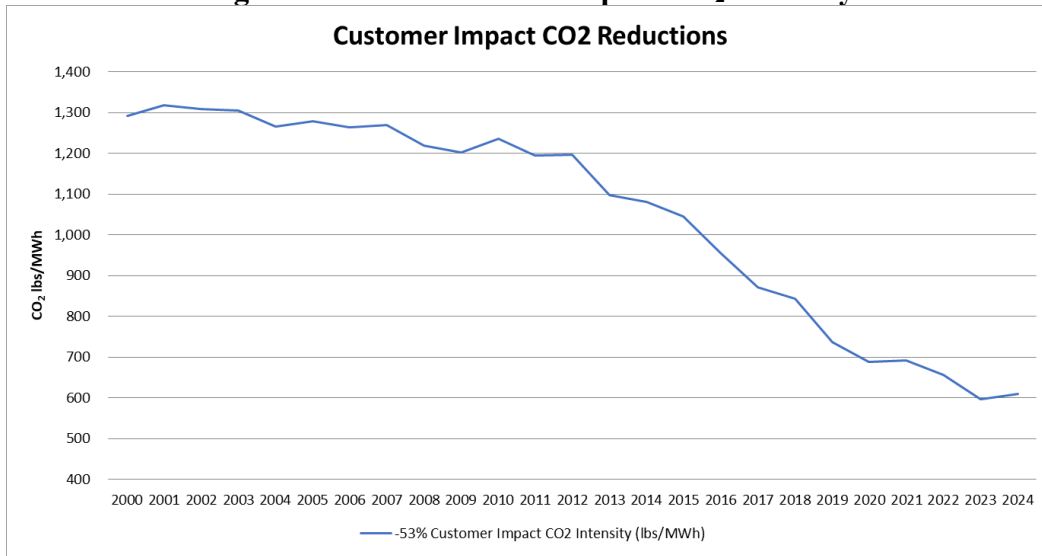
The energy mix chart shows the *sources of energy actually delivered* to the Company’s customers in 2024. Although still relatively small, energy supplied by solar in 2024 increased over 10% from 2023.

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

3.1.2 Company-Owned System Generation – Reduction in Emissions

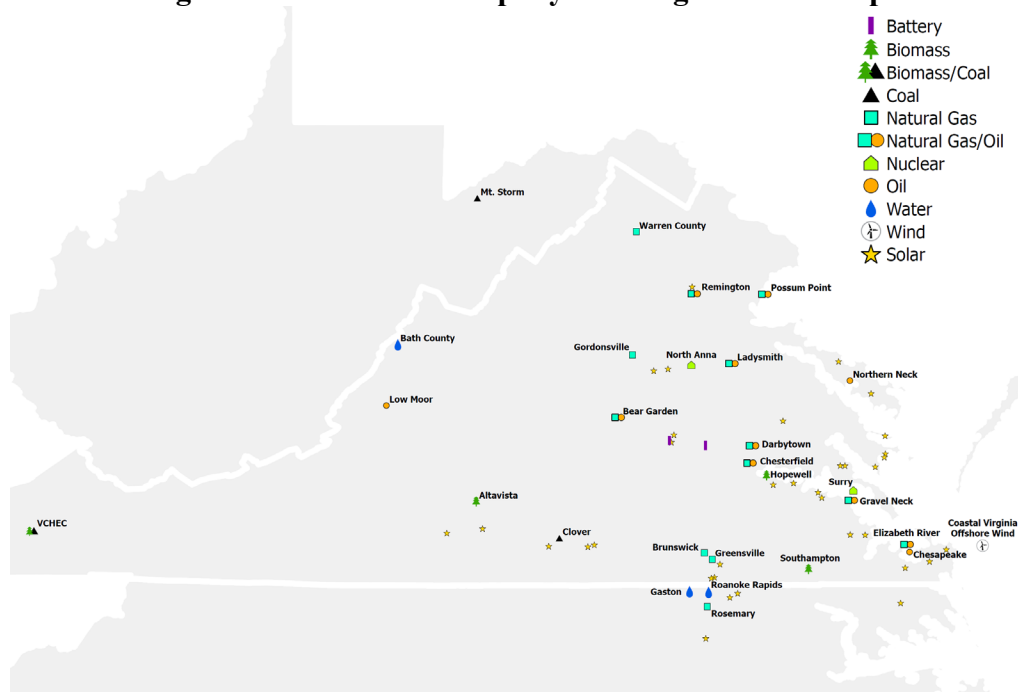
Over the past two decades, the Company has made changes to its generation mix that have significantly improved environmental performance. These changes include the retirement of certain units, the conversion of certain units to cleaner fuels, and the addition of air pollution controls. This integrated strategy has resulted in significant reductions in carbon dioxide (“CO₂”) emission intensity. CO₂ intensity is the quantity of emissions per megawatt hour (“MWh”) delivered to customers. This calculation includes emissions from any source used to deliver power to customers, including Company-owned generation, PPAs, and net purchased power. As shown in Figure 3.1.2.1, customer impact CO₂ intensity has decreased by 53% since 2000.

Figure 3.1.2.1: Customer Impact CO₂ Intensity



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

Figure 3.1.2.2: 2025 Company-owned generation map



Renewable energy resources not only provide a carbon-free energy alternative to power but also contribute several additional grid reliability benefits, including diversification, resilience to

extreme weather, and support of energy storage solutions. Energy storage plays a vital role in enhancing grid reliability by balancing supply and demand, providing backup power, reducing peak demand costs, and supporting renewable energy integration. The sections below discuss future generation resources that are planned or under development. Appendix 3C provides additional details

3.2 Building Renewable Energy Resources

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

3.2.1 Solar Facilities

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

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

3.2.2 Energy Storage

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

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

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

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

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

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

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

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

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

3.3 Resource Adequacy

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

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

enhanced coordination across the Eastern Interconnection will be needed to maintain system balancing and ramping needs and to ensure system reliability.

3.3.1 Near-term Supply Outlook in PJM

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

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

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

3.3.2 Reserve Requirements

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

3.4 Nuclear

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

3.4.1 Small Modular Reactors

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

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

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

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

Dominion Energy is actively advancing its continued evaluation of SMR technologies and potential deployment. Following the July 2024 Request for Proposals, the Company continues to analyze the feasibility of siting one or more SMRs at the North Anna Power Station. The Company also continues to explore opportunities for innovative financial partnerships with third parties and

high load customers, which may provide avenues for earlier deployment of SMRs than reflected in the Portfolios discussed in Chapter 5 of this 2025 IRP Update.

3.4.2 Traditional Scale Reactors

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

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

3.5 Reliability Resources Under Development

3.5.1 Natural Gas-Fired Units

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

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

energy resources. The Company is evaluating sites and equipment for the construction of new gas-fired units.

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

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

3.5.2 Future Supply-Side Resource Options

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

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

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

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

scalability, as well as hurdles to large-scale deployment like permitting, environmental, and safety requirements.

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

The Company is also evaluating additional LDES technologies such as:

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

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

3.6 The Five-Year Reliability Plan

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

3.6.1 Generation Reliability and Resource Adequacy

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

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

- Continue the development of gas-fired generation, including but not limited to, brownfield sites to take advantage of existing CIRs.
 - Continue evaluating opportunities for uprates or increased CIRs at existing generating units, as presented in Appendix 3B-11.
 - Advance the development of SMRs, as discussed in Chapter 3.4.1.
- Maintain existing generating units to maximize their performance and ensure regulatory compliance:
 - Continue necessary operation and maintenance and capital expenses in each unit.
 - Continue to petition for regulatory approvals of investments necessary to comply with environmental rules, including those described in Chapter 5.1.
- Maintain and enhance fuel security for existing units:
 - The Company has received a Certificate of Public Convenience and Necessity Amendment and has begun construction on a liquefied natural gas (“LNG”) Storage Facility (Case No. PUR-2024-00096), which will provide backup fuel to the Company’s critically important Greenville and Brunswick Power Stations.
- Pilot energy storage projects, as discussed in Chapters 3.2.2 and 3.5.2.
- Continue to execute on the VCEA mandates and continue to meet targets under North Carolina’s renewable energy portfolio standard at a reasonable cost and in a prudent manner, and submit its annual compliance report and compliance plan to the NCUC.

3.6.2 Demand-Side Management

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

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

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

3.6.3 Transmission

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

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

3.6.4 Distribution

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

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

Chapter 4. Commitment to Affordability

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

4.1 Residential and Commercial Energy Rates Comparison

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

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

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

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

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

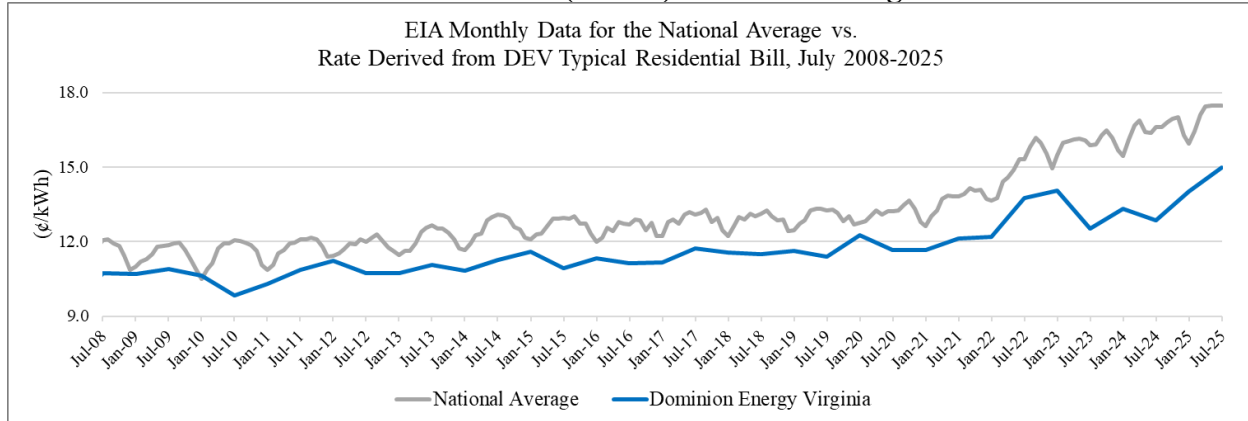
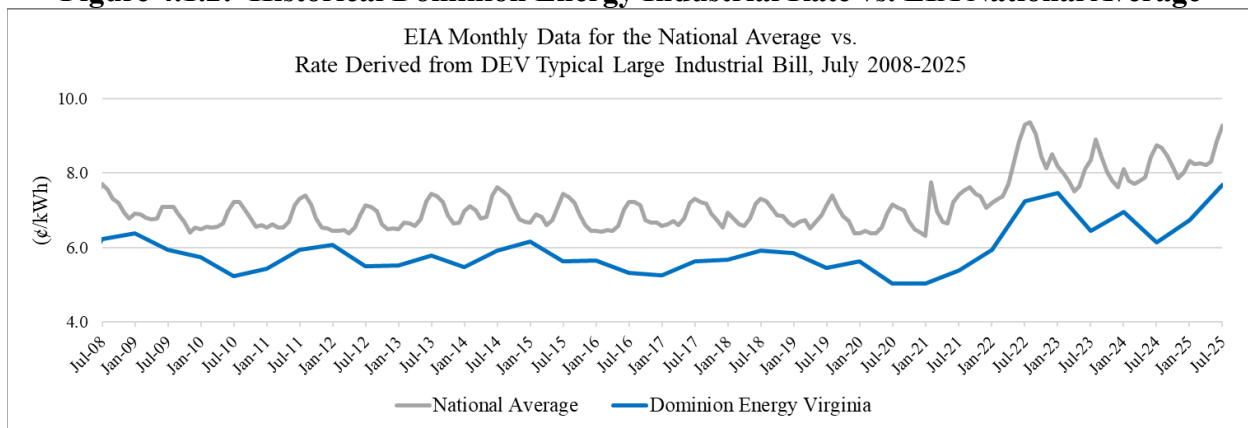


Figure 4.1.2: Historical Dominion Energy Industrial Rate vs. EIA National Average



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

4.2. Bill Analysis

4.2.1 Virginia

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

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

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

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

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

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

4.2.2 North Carolina

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

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

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

Chapter 5. Expansion Plan Modeling Assumptions and Results

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

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

5.1 Modeling Overview

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

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

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

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

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

Figure 5.1.1: Summary of Modeling Assumptions

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

Figure 5.1.2 Summary of Annual and Total Plan Resource Build Limits

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

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

5.1.1 Primary Portfolios

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

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

Table 5.1.1.1: Primary Portfolios Modeling Results Summary

	Company Preferred Plan	Least Cost VCEA Compliant without EPA	Forced Retirements by 2045
NPV Total (\$B)¹	\$148.7	\$142.1	\$170.6
Construction CAPEX² (\$B)	\$91.8	\$80.1	\$270.4
Approximate CO₂ Emissions from Company in 2045 (Metric Tons)	39.9 M	49.2 M	7.3 M
Solar (MW)	17,534	17,534	19,754
Wind (MW)	3,460	3,460	3,460
Storage (MW)	2,000	2,000	9,075
Nuclear (MW)	1,944	1,296	12,244
Natural Gas Fired (MW)	8,510	8,510	3,814
Retirements (MW)	-	-	12,705

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

² Represents incremental capital investment for generic resources selected in each Portfolio.

Overview of the Results of the Primary Portfolios

The following are key observations for the Primary Portfolios:

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

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

NPV of the Primary Portfolios

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

Table 5.1.1.2: NPV results for the Primary Portfolios

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

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

Company Preferred Plan

The Company Preferred Plan is a least cost VCEA compliant portfolio that meets all applicable requirements of the VCEA and then selects resources on a least-cost basis. This Portfolio includes the significant development of solar, wind, and energy storage envisioned by the VCEA, petitioned

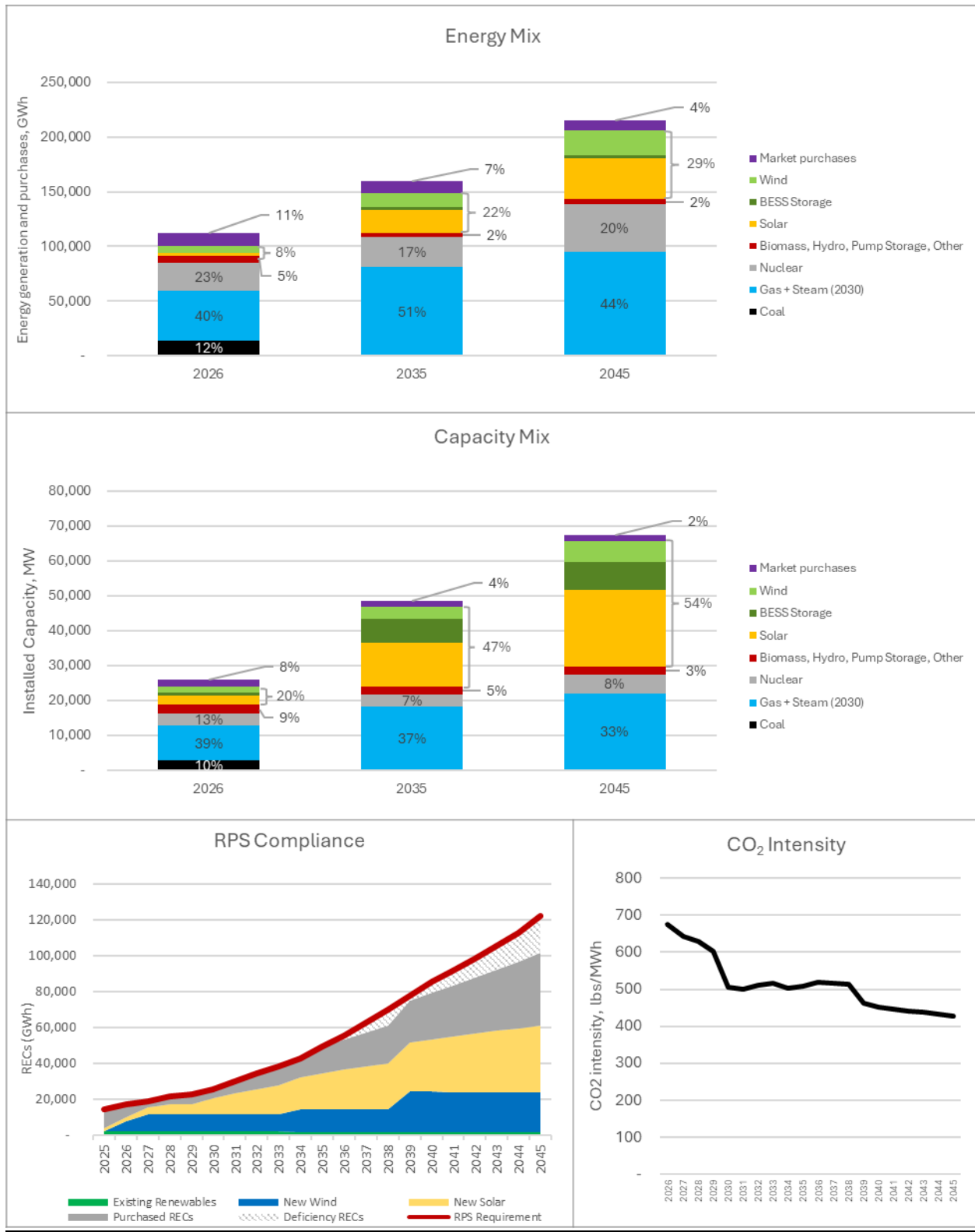
by 2035 and built by 2039. Furthermore, this Portfolio builds additional solar resources in the form of PPAs, beyond what is required by the VCEA, building a total of 17.5 GW of solar and 2 GW of storage resources. This Portfolio also includes the development of six SMRs, 3.4 GW of offshore wind, and 8.5 GW of gas-fired assets to address future capacity, energy, and system reliability needs. This Portfolio would require the Company to petition the Commission for a reliability exception outlined in the VCEA in order to preserve existing and planned fossil generation from retirement in 2045.

Figure 5.1.1.3: Company Preferred Plan Summary

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

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

Company Preferred Plan Dashboard



Least Cost VCEA Compliant without EPA Portfolio

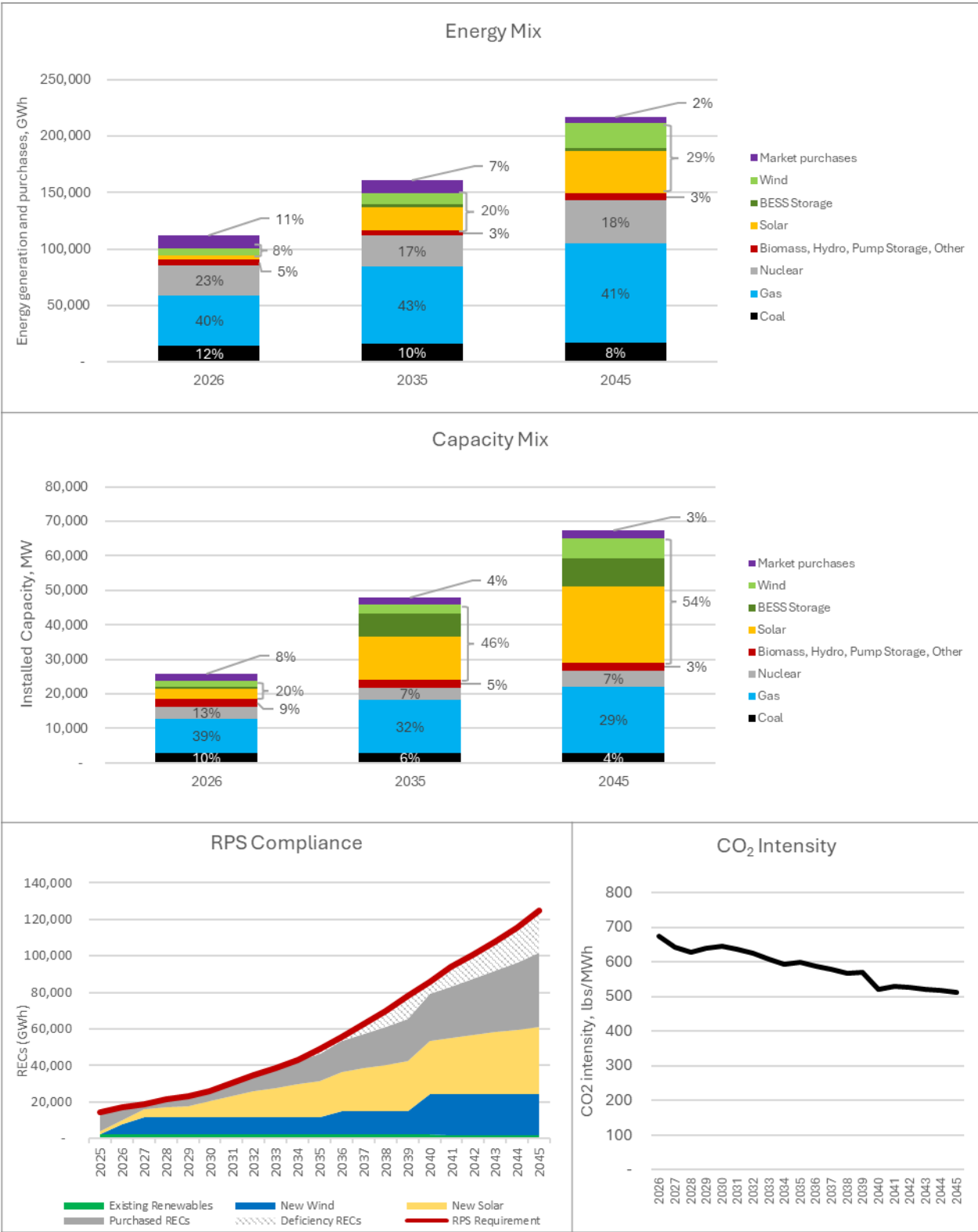
Earlier this year, the EPA began taking steps to repeal many of the 2024 EPA regulations which is further discussed in Appendix 5A. As such, the VCEA without EPA Portfolio utilizes a commodity price forecast that assumes that the 2024 EPA regulations are overturned. In addition, compliance with those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

Figure 5.1.1.4: Least Cost VCEA Compliant Without EPA

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

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

Least Cost VCEA Compliant without EPA Dashboard



Forced Retirements by 2045 Portfolio

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

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

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

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

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

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

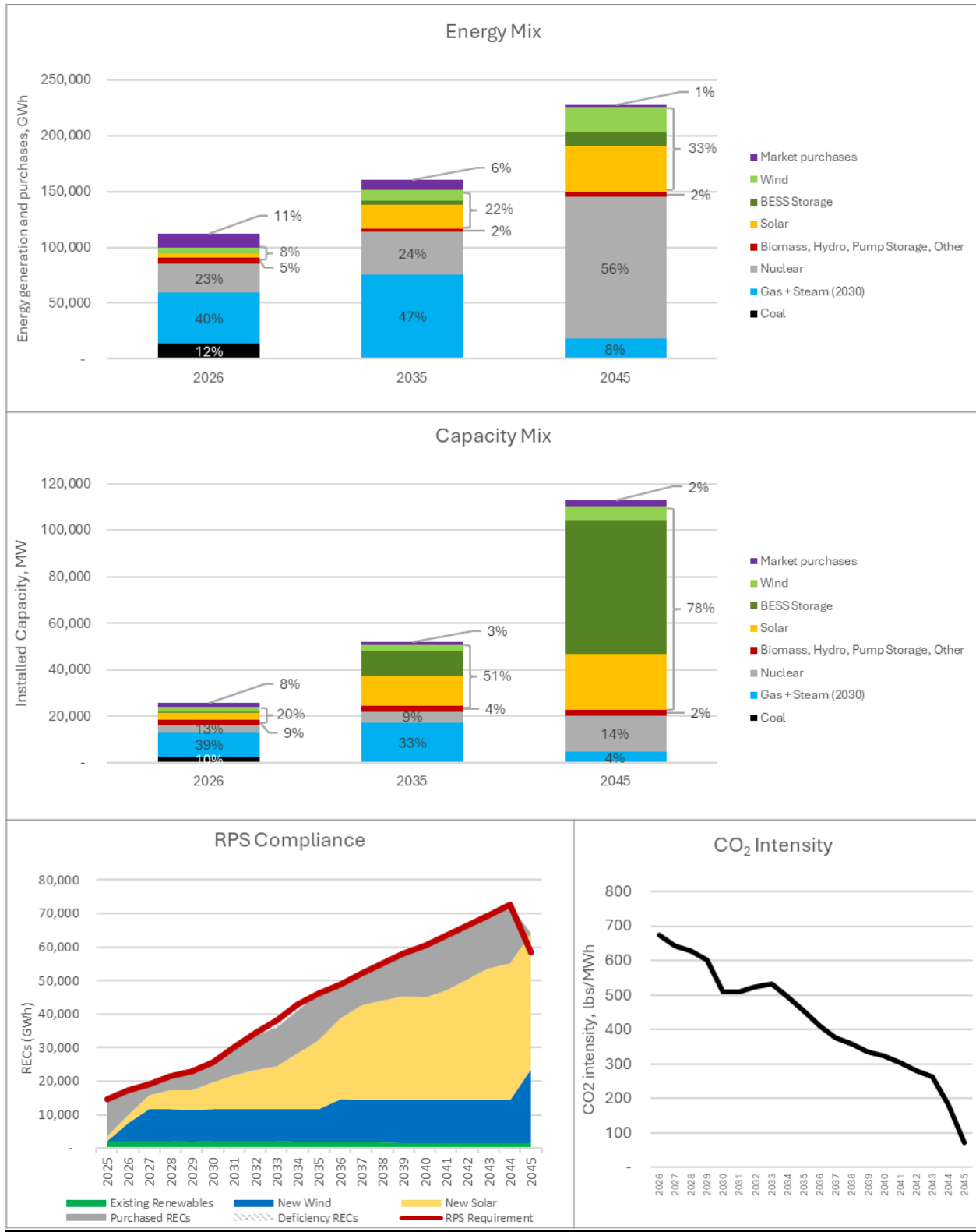
The Company does not consider this to be a feasible Portfolio based on the assumptions beyond reasonable build limits, customer affordability concerns, capital requirements and reliability concerns associated with retiring dispatchable generation during a time of significant load growth. As stated in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

Figure 5.1.1.5: Forced Retirements by 2045

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

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

Forced Retirements by 2045 Portfolio Dashboard



5.2 Secondary Portfolio

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

Table 5.2.1: Secondary Portfolio Modeling Results Summary

	NCUC Directed
Net Present Value (“NPV”) Total (\$B)	\$147.9
Approximate CO₂ Emissions from Company in 2045 (Metric Tons)	38.0
Solar (MW)	22,274
Wind (MW)	3,460
Storage (MW)	2,950
Nuclear (MW)	1,620
Natural Gas Fired (MW)	8,510
Retirements (MW)	-

NCUC Directed

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

Table 5.2.2: Secondary Portfolio Modeling Results Summary

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

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

Table 5.2.3: NPV results for the Secondary Portfolio

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

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

5.3 Sensitivity Analyses

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

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

Figure 5.3.1: 2025 Plan Sensitivities on Load Forecast

	Company Preferred Plan/PJM Derived Load Forecast	High Load Forecast Sensitivity	Low Load Forecast Sensitivity	Company Load Forecast Sensitivity
NPV Total (\$B)	148.7	169.8	132.8	145.7
Approximate CO₂ Emissions from Company in 2045 (Metric Tons)	39.9	42.0	35.3	38.9
Solar (MW)	17,534	17,534	17,534	17,534
Wind (MW)	3,460	3,460	3,460	3,460
Storage (MW)	2,000	4,350	2,000	2,000
Nuclear (MW)	1,944	3,564	-	1,944
Natural Gas Fired (MW)	8,510	8,926	8,510	8,510
Retirements (MW)	-	-	-	-

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

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

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

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

Figure 5.3.2: 2025 Portfolio Sensitivities

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

5.4 Extreme Weather Analysis

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

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

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

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

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

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

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

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

5.5 Retirement Analysis

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

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

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

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

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

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

Other quantitative and qualitative considerations must be prudently factored into such determinations, such as remaining useful life, capacity and energy replacements, system reliability, fuel contracts, transmission system considerations, personnel, impact of continued operation of the unit(s) on the local economy, and pending environmental regulations, to name a few. Modeling in this 2025 IRP Update is based on normal weather and models the complete system, which does

not fully capture the value of a unit that may be based on location, fuel diversity, value in extreme weather scenarios, operational flexibility, and black start capability, among other factors. The Company has not made any decision regarding the retirement of any current generating unit and does not anticipate any such retirements before 2045. Appendix 3B-10 lists the generating units considered for potential retirement in the Company Preferred Plan.

Chapter 6. Serving Our Communities

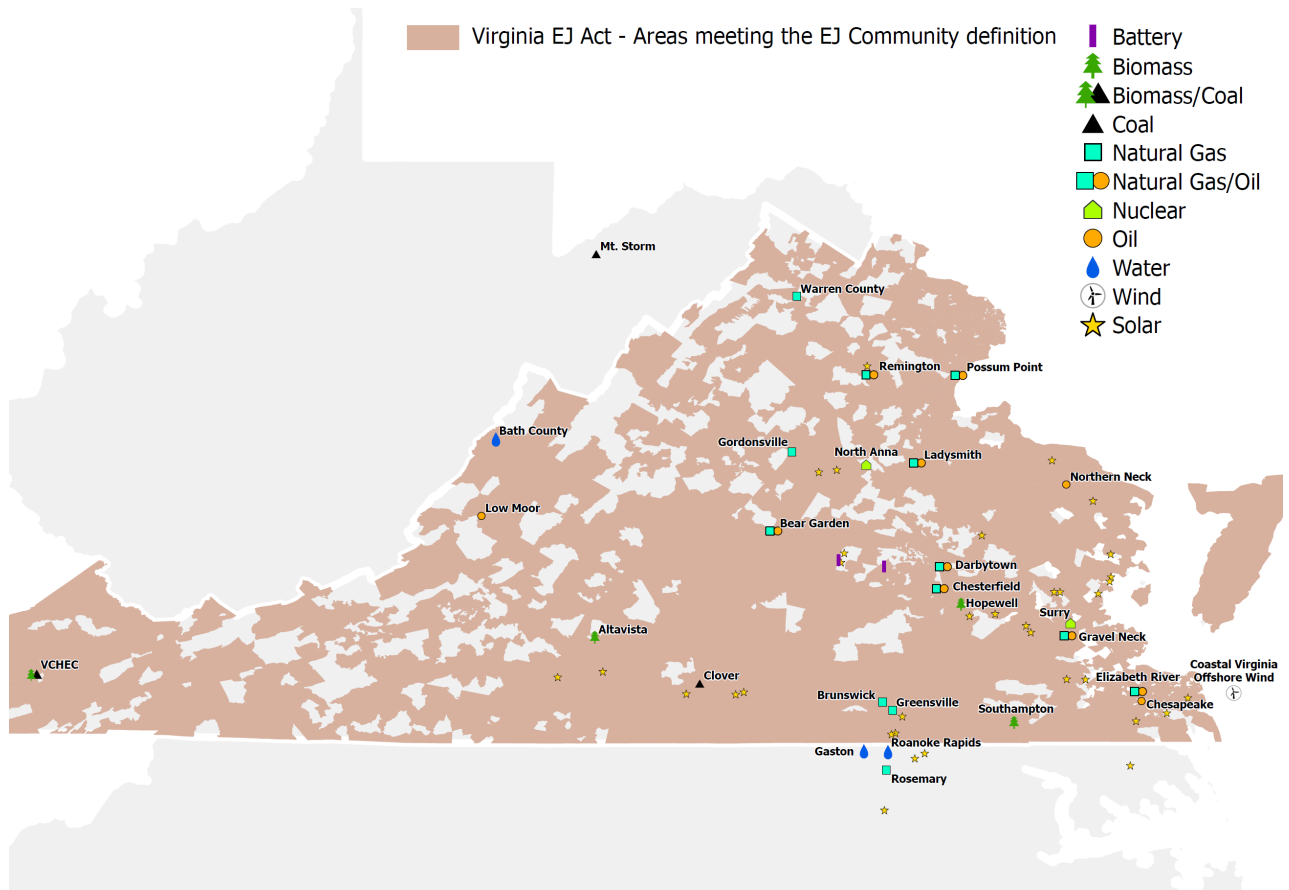
Dominion Energy’s environmental justice (“EJ”) policy commits to making EJ considerations part of our everyday decision-making. EJ reviews are undertaken for all major projects. We work closely with all appropriate federal, state, local, and tribal agencies to mitigate environmental impacts through the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

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

6.1 Environmental Justice

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

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



6.2 Customer Education

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

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

Website and Supporting Print Collateral

The Dominion Energy website—<https://www.dominionenergy.com>—serves as a central hub for public education. The Company offers program- and project-specific information, factsheets, brochures, videos, and other supporting documents to provide background and updates on the

benefits and enhanced capabilities associated with various investments and initiatives. These include, but are not limited to, approved elements of the Grid Transformation Plan, major infrastructure projects, and new offerings such as rates, tools, and mobile apps as they become available.

Social Media

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

The Company's X® account is available online at: <https://x.com/dominionenergy>.

The Company's Facebook® account is available online at:

<https://www.facebook.com/dominionenergy>.

The Company's YouTube® account is available online at

<https://www.youtube.com/dominionenergy>.

The Company's Instagram® account is available online at

<https://www.instagram.com/dominionenergy/>.

The Company's LinkedIn® account is available online at

<https://www.linkedin.com/company/dominionenergy/>.

News Releases

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

Energy Conservation Programs

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

Community Outreach – Trade Shows, Exhibits, and Speaking Engagements

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

<https://www.dominionenergy.com/our-company/customers-and-community/educational-programs>.

6.3 Economic Development Rates (for qualifying customers)

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