Dominion Energy®

Actions Speak Louder

Planning and investing for our future.

2021 Update to the 2020 Integrated Resource Plan

Virginia Electric and Power Company

Case No. PUR-2021-00201 and Docket No. E-100, Sub 165

Filed September 1, 2021

Our Company

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Managing our electric rights-of-way to increase habitats for birds, bees, butterflies, and other pollinators.

Our Company

Executive Summary

Dominion Energy Corporate Office; 600 Canal Place; Richmond, VA.

Headquartered in Richmond, Virginia, Virginia Electric and Power Company (the "Company") currently serves approximately 2.6 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company is a subsidiary of Dominion Energy, Inc. ("Dominion Energy")—one of the nation's largest producers and transporters of energy, energizing the homes and businesses of more than seven million customers in 16 states with electricity or natural gas.

In 2020, the Company filed a full integrated resource plan (the "2020 Plan") with the Virginia State Corporation Commission ("SCC") (Case No. PUR-2020-00035) and with the North Carolina Utilities Commission ("NCUC") (Docket No. E-100, Sub 165). On February 1, 2021, the SCC issued its Final Order on the 2020 Plan setting forth information for the Company to include in future integrated resource plans and update filings. A final order on the 2020 Plan from the NCUC has not been issued as of the date of this filing. The Company now files this 2021 update ("2021 Update") to the 2020 Plan with the SCC and the NCUC consistent with all relevant Virginia and North Carolina laws, regulations, and commission orders.

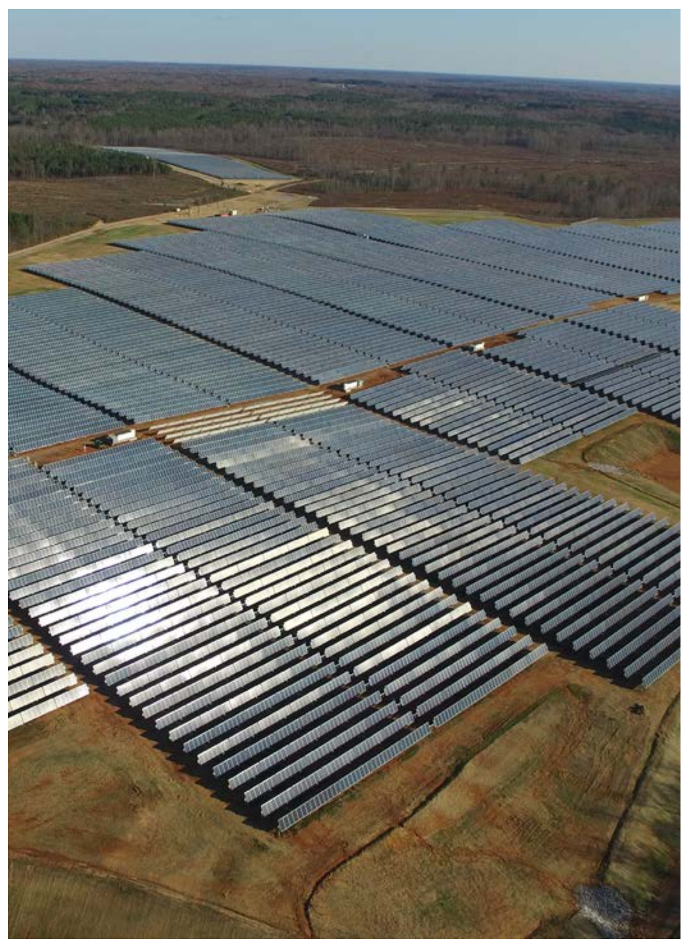
The 2020 Plan explained the Company's commitment to a clean energy future consistent with Dominion Energy's company-wide commitment to achieve net zero carbon dioxide ("CO_2") and methane emissions by 2050; the requirements established in Virginia aimed at a clean energy future through the Virginia Clean Economy Act of 2020 ("VCEA") and other legislation; and the goal of North Carolina to achieve statewide carbon neutrality by 2050. That commitment has not changed. Indeed, over the past year or so, the Company has:

- Retired approximately 770 megawatts ("MW") of oil-fired generation (in 2020);
- Placed approximately 250 MW of Company-owned solar in service (in 2020);
- Developed and plans to petition for approval of significant new solar and energy storage resources, including 14 utility-scale projects totaling approximately 746 MW of solar and 70 MW of energy storage and two distributed solar projects totaling approximately 3.6 MW;

- Developed significant new solar and energy storage resources from third-party resources and plans to petition for prudence determinations to enter into up to 25 power purchase agreements ("PPAs") for 33 separate solar and energy storage resources totaling approximately 256 MW of solar and 33 MW of energy storage;
- Received approval from the Nuclear Regulatory Commission ("NRC") for the license extensions for the Company's nuclear units at Surry Power Station, and continued to work to extend the licenses of its nuclear units at North Anna Power Station;
- Completed construction of the 12 MW Coastal Virginia Offshore Wind ("CVOW") demonstration project, and continued the development of the larger build-out of offshore wind generation off the coast of Virginia of up to 180 turbines totaling approximately 2,600 MW;
- Continued to transform the Company's distribution grid to provide an enhanced platform for distributed energy resources ("DERs") and targeted demand-side management ("DSM") programs; more secure and reliable service, leading to the increased availability of DERs; and more ways for customers to save energy and money through DSM programs and other rate offerings; and
- Launched the Smart Charging Infrastructure Pilot Program to provide rebates for electric vehicle ("EV") charging, including public fast charging, multi-family, workplace, and transit, and joined the Electric Highway Coalition to facilitate long-distance electric travel for customers and Company fleet vehicles.

Over the long term, achieving the clean energy goals of Virginia, North Carolina, and the Company will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy. This includes support for the testing and deployment of technologies such as large-scale energy storage; renewable natural gas; vehicle-to-grid; hydrogen; advanced nuclear, including small modular reactors ("SMRs"); and carbon capture and sequestration, all of which have the potential to significantly reduce greenhouse gas emissions.

The 2021 Update was prepared for the Dominion Energy Load Serving Entity ("DOM LSE") within PJM Interconnection, LLC ("PJM"). It covers the 15-year period beginning in 2022 and continuing through 2036 (the "Planning Period"), using 2021 as the base year. In certain instances, the Company evaluates the longer 25-year period of 2022 to 2046 (the "Study Period"). Overall, the 2021 Update is an interim update meant for use as a long-term planning document based on a "snapshot in time" of current technologies, market information, and projections, and should be viewed in that context, not as a decision to pursue any particular project or action. It is also worth noting that this 2021 Update is a snapshot in time amidst a continuing global pandemic, adding to the usual caveats about the dynamic nature of long-term planning.



Scott Solar Farm; Powhatan, VA.

In this 2021 Update, the Company has updated its long-term planning assumptions, including load forecasts, commodity prices, and projected costs of future resources, and has incorporated a social cost of carbon. Otherwise, the three alternative plans (the "Alternative Plans") presented in this 2021 Update are similar to those shown in the 2020 Plan.

- **Plan A:** This Alternative Plan presents a least-cost plan that meets only applicable carbon regulations and the mandatory renewable energy portfolio standard program ("RPS Program") requirements of the VCEA. The Company presents this Alternative Plan in compliance with prior SCC and NCUC orders and for cost comparison purposes only. It is important to emphasize that Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.
- **Plan B:** This Alternative Plan sets the Company on a trajectory toward dramatically reducing greenhouse gas emissions, taking into consideration future challenges and uncertainties. Plan B includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B also preserves natural gas-fired generation to address future system reliability, stability, and energy independence issues.
- **Plan C:** This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045 resulting in zero CO_2 emissions from the Company's fleet in 2046. If the Company retires all carbon-emitting units by the end of 2045, approximately 10 GW of new incremental battery storage would be needed to continue to reliably meet customer load. For context, the Company currently has approximately 100 MW of energy storage under development, in addition to its 16 MW of pilot projects. Over time, as more renewable energy and storage resources are added to the system, the Company will learn if Plan C is capable of maintaining a reliable system.

All Alternative Plans include Virginia's participation in Regional Greenhouse Gas Initiative ("RGGI"), utilize the load forecast prepared by PJM, and assume a capacity factor for all existing and future solar resources of 21.2%, which is the 3-year average of solar tracking facilities in Virginia. The 2021 Update also presents multiple sensitivities on various assumptions. Notably, the Company presents sensitivities on Alternative Plan B using (i) the load forecast it prepared, which the Company believes presents a more reasonable forecast of future growth, and (ii) a projected capacity factor for future solar resources that better reflects their long-term output.

The following table presents a high-level summary of the Alternative Plans:

Summary Table: 2021 Update Results

	Plan A	Plan B	Plan C
NPV Total ($B)	$46.0	$67.9	$70.7
Approximate CO_2 Emissions from Company in 2046 (Metric Tons)	18 M	2 M	0
Solar (MW)	820 15 yr. 2,140 25 yr.	14,310 15 yr. 17,790 25 yr.	14,310 15 yr. 20,550 25 yr.
Wind (MW)	— 15 yr. — 25 yr.	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,614 25 yr.
Storage (MW)	— 15 yr. — 25 yr.	2,713 15 yr. 2,713 25 yr.	3,793 15 yr. 12,043 25 yr.
Natural Gas-Fired (MW)	970 15 yr. 970 25 yr.	— 15 yr. — 25 yr.	— 15 yr. — 25 yr.
Retirements (MW)	2,567 15 yr. 2,567 25 yr.	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 13,356 25 yr.

As can be seen in the table above, Alternative Plans B and C are very similar over the first 15 years. This general alignment suggests a common pathway for the Company to pursue now while allowing new technologies to mature. While all Alternative Plans in this 2021 Update incorporate only known, proven technologies, the Company fully expects that new technologies could take the place of today's technologies over the Planning Period. The Company intends to explore new and promising technologies that support a cleaner energy future and that will enable the Company to achieve its environmental goals, as well as the goals of Virginia and North Carolina. The Company will provide information on these developments in future filings.

Our Company

Discussion of Significant Developments

The Company serves approximately 2.6 million electric customers in Virginia and North Carolina.

The Company's comprehensive planning process considers significant emerging policy, market, regulatory, and technical developments that could affect its operations and, in turn, its customers. The Company provides the following discussion of significant developments requiring a major revision to the 2020 Plan, consistent with the requirements of the SCC and the NCUC. The Company must exercise some judgment when interpreting the terms "significant" and "major." This 2021 Update, therefore, includes a discussion of only those external events which, in the Company's judgment, require revision to the 2020 Plan.

PJM Load Forecast

PJM incorporated adjustments to its load forecasting methodology into its 2021 PJM Load Forecast that, together with a better understanding of PJM modeling and forecast results, present significant technical and practical challenges and call into question the use of the PJM load forecast in a long-term planning model. These challenges include: (i) disconnect with forecast starting point; (ii) focus on short-term accuracy; (iii) reliance on non-fundamental drivers; (iv) treatment of region-specific nuances; (v) forecast timing; and (vi) forecast translation from DOM Zone to DOM LSE.

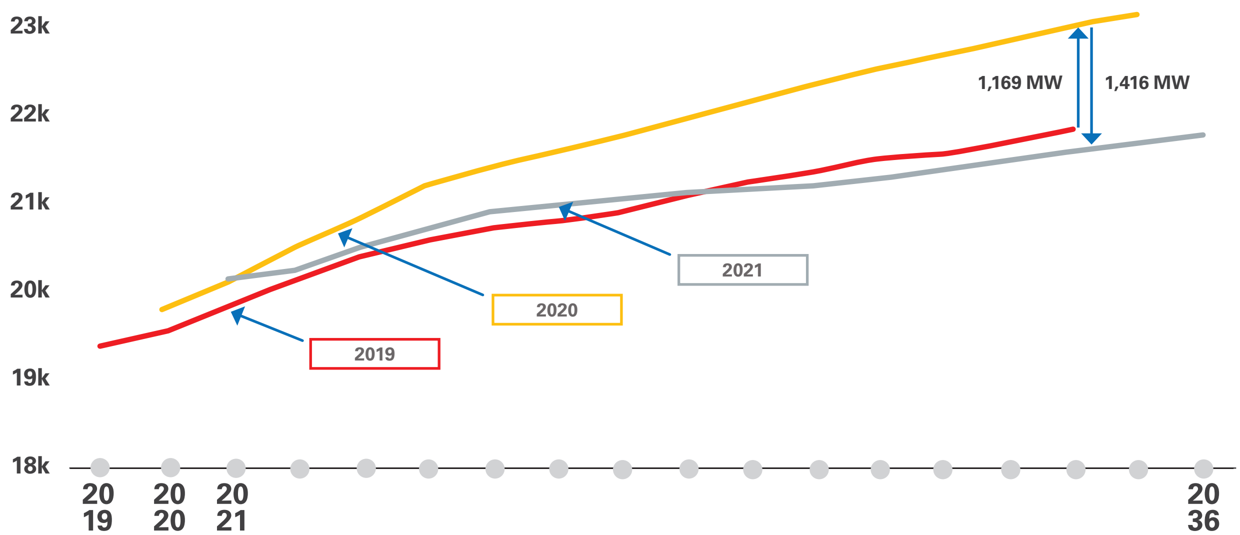
Disconnect with forecast starting point. There is an apparent disconnect in the starting point between actual and forecasted energy in the 2021 PJM Load Forecast. The 2021 PJM Load Forecast starts at 100,235 gigawatt-hours ("GWh"), which is well below both the 105,074 GWh energy on an actual basis and the 105,272 GWh energy on a weather-normal basis for the 12-month period August 2020 to July 2021. As another point of context, on August 12, 2021, DOM Zone reached a new all-time summer peak load of 20,406 MW.[1] The current PJM forecast projects DOM Zone not reaching this level until 2023 for the non-coincident peak and 2027 for the coincident peak. These data points illustrate that PJM's starting point on peak and energy forecast is understated.

Focus on short-term accuracy. PJM's model selection criteria suggest that its forecast is more focused on short-term accuracy. Specifically, PJM model testing has been focused on higher accuracy in the 3-year forecast horizon, which coincides with the PJM capacity market's clearing window, as opposed to the 15- to 25-year window used in the Company's long-term planning process.

[1] The weather on this day was only slightly above 20-year average temperatures at the time of the peak.

As one of the outcomes of the resulting methodology changes, PJM's forecasts have changed materially over the last few years. As shown in the figure, the forecast for 2034 increased by 5.4% and subsequently decreased by 6.2% in the next year. Utilization of a forecast that changes significantly in magnitude and direction from one year to the next presents significant challenges from a long-term planning perspective.

Figure 1.1.1: PJM Forecast, 2019 through 2021



Reliance on non-fundamental drivers. In 2021, PJM introduced a numerical "trend" as an explanatory variable in its model as one of the key forecast methodology changes. This change was based on the model accuracy results of short-term (i.e., one to three years out) historical out-of-sample testing. While the trend variable might have shown more accurate results in the short-term historical testing, use of such a variable represents gaps in model specification that should be directly addressed, especially when the results are to be relied upon for long-term planning. Relying on a continued and growing impact of this trend variable for a 15-year forecast period resulted in a substantially lower forecast that is not supported by underlying fundamentals.

Treatment of region-specific nuances. PJM forecasts for over twenty load zones, maintaining a largely consistent forecasting methodology for each. This approach makes it difficult to appropriately capture modeling nuances specific to different service territories. For example, the 2021 PJM Load Forecast incorporates a data center forecast provided by the Company but does so without isolating the non-data center zonal load. Instead, PJM forecasts non-data center zonal load separately, making the cause and effect of economic variables more difficult to isolate in its forecast models.

Forecast timing. PJM issues its load forecast report once a year in late December or early January.[2] By the time the forecast is utilized in the Company's modeling, the assumptions, which are mostly locked in by September of the prior year, are about nine months old. Significant developments have occurred in the past which makes the forecast obsolete. For example, between the fall of 2020 and the summer of 2021, data center growth occurred faster than projected; and the pandemic impacts on overall loads significantly declined from the initial pandemic periods. Therefore, lack of a full forecast update close to the time of its use renders the forecast outdated and forces its use when the underlying assumptions are no longer valid.

[2] PJM also conducts a forecast update in July; however, it is not comprehensive and very limited forecast information is published.

Forecast translation from DOM Zone to DOM LSE. Deriving a DOM LSE forecast from PJM's DOM Zone forecast presents challenges and limitations that result in unnecessary sources of forecast error. For example, sufficient details are not available to isolate the embedded energy efficiency savings within PJM forecast generally or the DOM LSE component of these savings specifically. Similarly, a behind-the-meter solar load forecast adjustment is made for the entire DOM Zone in PJM's forecast, which cannot be isolated for DOM LSE. Additionally, PJM does not forecast customer class sales, and there is not sufficient data available to derive them from the PJM energy forecast, making customer bill analyses challenging. These sources of forecast error can be avoided by directly forecasting DOM LSE.

Based on these analytical issues, the Company believes that the 2021 PJM Load Forecast presents an understated view of future load growth. Between 2021 and 2026, the 2021 PJM Load Forecast shows the DOM Zone growing from 100,235 GWh to 103,897 GWh, an increase of 3,662 GWh. By contrast, the Company projects that data center demand served by the Company alone will increase by approximately 8,200 GWh in the same period.[3] This implies that PJM forecasts non-data center load in the DOM Zone will decrease by more than 4,500 GWh between 2021 and 2026, an outcome which is not supported by fundamentals. Because growth in DOM Zone load also includes substantial data center load growth in Northern Virginia Electric Cooperative service territory, this implied decrease in DOM Zone load would be even higher if all data center growth in DOM Zone is included. The Company has shared these modeling concerns with PJM, and will continue to collaborate with PJM to improve long-term forecast accuracy.

The Company felt it necessary to include a sensitivity as what it believes to be a more accurate representation of future load growth in its service territory. Accordingly, while the Company has utilized the 2021 PJM Load Forecast in the development of all Alternative Plans, as required, the Company also shows a sensitivity of Alternative Plan B using the 2021 Company Load Forecast, which is not impaired by the methodological challenges discussed above.

Social Cost of Carbon

The VCEA added a requirement to include the social cost of carbon as a benefit or a cost, whichever is appropriate, in any application to construct new generating facilities. The social cost of carbon is an estimate in dollars of the economic damages that result from emitting one ton of carbon into the air. While social cost of carbon estimates in dollars per ton can vary significantly between organizations, the federal government has produced and updated a forecasted social cost of carbon since the 1980s. In February 2021, the Biden Administration published a revised social cost of carbon forecast that begins at $51 per metric ton in 2021.[4]

In this 2021 Update, the Company includes the social cost of carbon as an indirect cost of carbon emissions. This indirect cost was included in addition to the direct cost of carbon generated by the market under applicable carbon regulations. The green line in Figure 1.2.1 depicts the dispatch carbon price included in PLEXOS, a utility modeling and resource optimization tool.

Brunswick Power Station.

[3] PJM's 2021 Load Forecast utilized DOM Zone data center forecast provided by the Company and Northern Virginia Electric Cooperative for their respective service areas. This forecast was provided for the period 2020 through 2025 and was prepared in the fall of 2020.

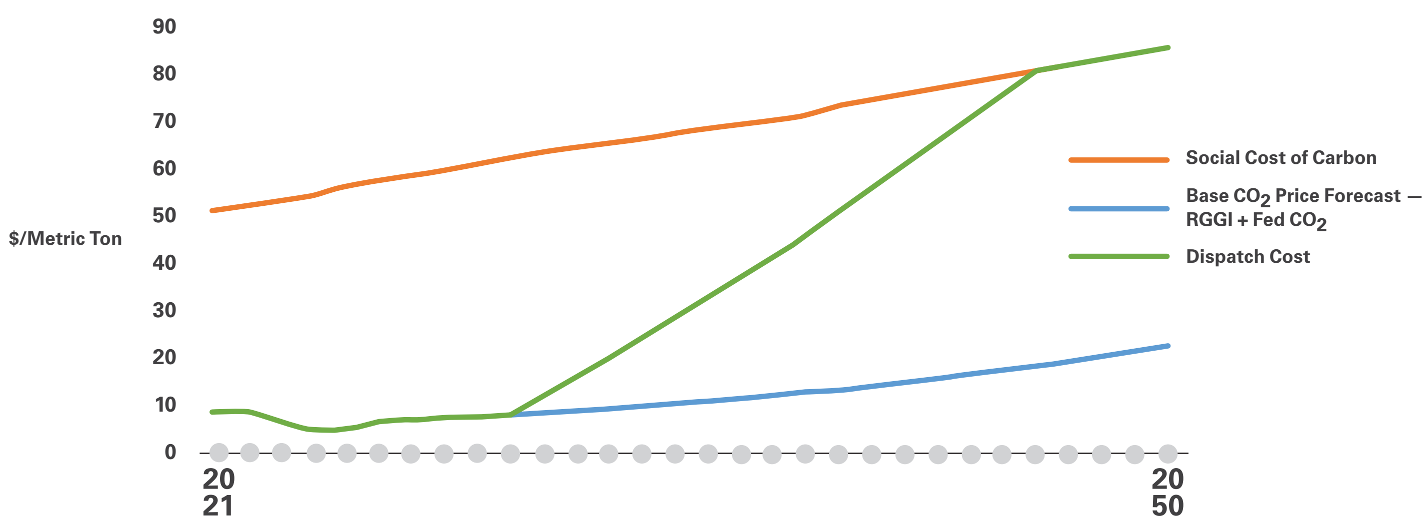
[4] See Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide, Interim Estimates Under Executive Order 13990 (Feb. 2021), available at https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

As shown in Figure 1.2.1, for the first ten years of the Study Period, the Company included a carbon dispatch adder equal to the forecasted price of a direct carbon tax. Starting in 2031, the Company then blended the forecasted social cost of carbon with the direct carbon tax through 2046 (i.e., the end of the Study Period). For example, 2031 included a carbon dispatch adder of which the social cost of carbon comprised 6.7%, 2032 included a dispatch adder of which the social cost of carbon comprised 13.3%, and so on. In 2046, and beyond, the Company included a carbon dispatch adder equal to the forecasted social cost of carbon.

The Company employed this blended approach for two primary reasons in this initial analysis. First, PJM market rules do not currently allow members to factor the social cost of carbon into their cost offers. The Company assumes that the PJM market rules may evolve within the next ten years, as PJM resolves stakeholder concerns over carbon emission leakage between jurisdictions and recognizes societal costs not currently included in offers. Second, the intervening 10-year period provides time for renewable energy facilities to be built to replace the fossil generation component of the Company's current resource portfolio.

Adding the social cost of carbon as an indirect cost, or "shadow price", results in the Company's carbon-emitting generating units operating less often, thus lowering projected carbon emissions from the Company's system. Nevertheless, these units stay available to ensure system reliability. Because the social cost of carbon is an indirect cost, these costs were not included in the net present value ("NPV") of the Alternative Plans; only costs related to the direct carbon tax were included in the NPV results.

Figure 1.2.1: Carbon Dispatch Price



This 2021 Update presents the Company's initial analysis incorporating the social cost of carbon into its long-term planning process. This analysis will continue to evolve over time. For example, the 2021 Update includes the social cost of carbon only as a cost for carbon-emitting generating units—not as a benefit for carbon-free generating facilities such as solar, wind, and nuclear. That said, the Company will include the social cost of carbon as a benefit in future applications for new clean energy generating facilities, as required by the VCEA.

The Company will revise this analysis as needed in future filings.

Commodity Price and Cost Assumptions

This 2021 Update incorporates updated commodity price forecasts and costs assumptions. The updated commodity price forecasts include the regional impacts of the VCEA along with other market developments identified by ICF Resources, LLC ("ICF"), such as Pennsylvania's participation in RGGI, effective in 2023.

This 2021 Update also incorporates updated build costs for new resources. Notably, build costs for battery storage decreased from the 2020 Plan and continue to decline throughout the Study Period based on short term expectations and National Renewable Energy Laboratory ("NREL") projections (conservative/high scenarios used) for utility scale lithium-ion 4-hour duration battery storage projects as referenced in the 2020 NREL Annual Technology Baseline. Solar build costs increased in the 2021 Update due to recent market trends.

PLEXOS Modeling Refinements

The Company primarily used PLEXOS to develop this 2021 Update. Since the 2020 Plan, the Company has included several refinements in PLEXOS to incorporate the many requirements of the VCEA. These refinements include:

- A dynamic RPS Program requirement based on forecasted customer sales;
- The ability to purchase renewable energy certificates ("RECs") from eligible market sources to satisfy a portion of the Company's RPS Program requirements;
- Deficiency payment logic that allows the model to choose a deficiency payment for RPS Program compliance, as established by the VCEA, if economically advantageous for customers compared to other options;
- Adjustments for excess RECs that can be sold to reduce customer cost; and
- Optimized generating unit retirement logic for least-cost modeling.

The Company will continue to refine its modeling as additional functionality becomes available in PLEXOS. For example, REC banking is not currently available in PLEXOS, but the Company will continue to pursue such improvements for future Plans.

Fixed Resource Requirement Alternative

As described in the 2020 Plan, the Company participates in the PJM capacity planning process to ensure adequate supply of capacity resources for its customer load. As a member of PJM, the Company has the option to secure capacity in order to satisfy mandated reliability requirements through either (i) the reliability pricing model ("RPM") forward capacity market or (ii) the fixed resource requirement ("FRR") alternative.

The Company has participated in the RPM forward capacity market since 2007, and has satisfied its capacity obligation through the RPM auction through May 31, 2022. In April 2021, the Company elected the FRR alternative, with a five-year commitment beginning June 1, 2022, based on its analysis that FRR would provide customer benefits. In the future, the Company could continue to elect the FRR alternative on a year-by-year basis or revert to the RPM forward capacity market with a five-year commitment. The Company will continue to evaluate its options to meet its capacity obligations (i.e., FRR and RPM) to ensure the best result for its customers.

For purposes of long-term planning, the Company continues to model the PJM installed reserve margin requirement, which is not affected by the Company's election of the FRR alternative.

Nuclear Relicensing

An application for a subsequent or second license renewal ("SLR") is allowed during a nuclear unit's first period of extended operation—that is, in the 40 to 60 years range of its service life. A successful SLR application allows nuclear units to operate for an additional 20-year period.

As with other nuclear units, those at the Company's Surry Power Station were originally licensed to operate for 40 years and then were renewed for an additional 20 years. Surry Units 1 and 2 became eligible for SLR in 2012 and 2013, respectively. In November 2015, the Company notified the NRC of its intent to file for SLR for those two nuclear units in accordance with Title 10 of the Code of Federal Regulations Part 54. The licenses for Units 1 and 2 were subsequently renewed on May 4, 2021, permitting continued operation through 2052 and 2053, respectively. Approval by the SCC will also be required for extending the licenses for Surry Units 1 and 2; therefore, the Company's current capacity and energy positions (e.g., as shown in Figures 2.1.1 and 2.1.2) do not include the SLR for these units in its existing generation.

At the Company's North Anna Power Station, Units 1 and 2 became eligible for SLR in 2018 and 2020, respectively. The North Anna SLR application was submitted to the NRC on August 24, 2020. In October 2020, the application was accepted for review by the NRC. This is an important milestone in that the application met the NRC requirements to move forward with both the technical and environmental review processes, which are now underway. The issuance of the renewed license is expected by May 2022, which is 18 months from the date when the application was accepted for review. This will preserve the option to continue operation of North Anna Units 1 and 2 until 2058 and 2060, respectively.

Surry Power Station; Surry County, VA.

Increasing Electrification

The electrification of transportation is accelerating in Virginia, North Carolina, the United States, and globally.

At the federal level, on August 5, 2021, President Biden signed an executive order to make half of all vehicles sold in 2030 zero-emission vehicles, which includes battery electric, plug-in hybrid electric, and fuel cell EVs. That executive order also initiates development of long-term fuel efficiency and emissions standards to save customers money, reduce pollution, boost public health, advance environmental justice, and address the climate crisis. Automobile manufacturers are making the shift to EVs as well. For example, Ford recently pledged that 40% of its vehicles sold by 2030 will be electric.

At the state level, the Virginia General Assembly passed multiple pieces of legislation earlier this year that provide additional support for transportation electrification. For instance, House Bill ("HB") 1965 requires manufacturers to offer EVs for sale in Virginia, making EVs more available to Virginians. HB 1979 creates a rebate program for the purchase or lease of new and used EVs. The General Assembly also passed HB 2282 earlier this year, which sets a policy to promoting private-sector competition and investment in transportation electrification, in tandem with enabling public utility programs to complement private-sector investments where most effective.

Dominion Energy supports transportation electrification, including the goal of net zero emissions in the transportation sector, which is the largest contributor of greenhouse gas emissions in the United States. On August 10, 2021, Dominion Energy announced a company-wide plan to convert a significant portion of its transportation fleet of 8,600 vehicles to electric power or a clean-burning alternative by 2030. Specifically, 75% of Dominion Energy passenger vehicles, including sedans and sport utility vehicles, will be converted to electric power by 2030. Half of all Dominion Energy work vehicles, from full-size pickup trucks, bucket trucks, to forklifts and all-terrain vehicles will be converted to plug-ins, battery EVs, or vehicles powered by clean-burning fuels such as hydrogen, renewable natural gas and compressed natural gas by 2030. After 2030, all new vehicles, including sedans and heavy-duty vehicles, that are purchased will be either electric or powered by alternative fuels.

Dominion Energy's green fleet includes electric, natural gas, and biodiesel vehicles that are helping it to lower carbon emissions.

This 2021 Update includes an EV load forecast. However, the electrification of transportation now stretches beyond passenger vehicles, to include medium and heavy-duty vehicles, airplane drones, boats and personal watercraft, all-terrain vehicles, trains, forklifts, and farm equipment. The Company is closely monitoring these developments and is actively evaluating opportunities to pilot some of these EVs internally. As an example, the Company has piloted electric forklifts, electric outboard motors, electric lawn mowers, and an all-terrain vehicle, and has a groundbreaking electric school bus program. Dominion Energy is also actively monitoring current and future external business opportunities associated with the electrification of transportation. There is also movement toward electrification of farming and food production in the agriculture sector.

Autonomous Electric Shuttle; Fairfax County, VA.

As additional sectors of society work to decarbonize through electrification, the Company expects to grow its system to accommodate their needs.

Our Company

Results of 2021 Update

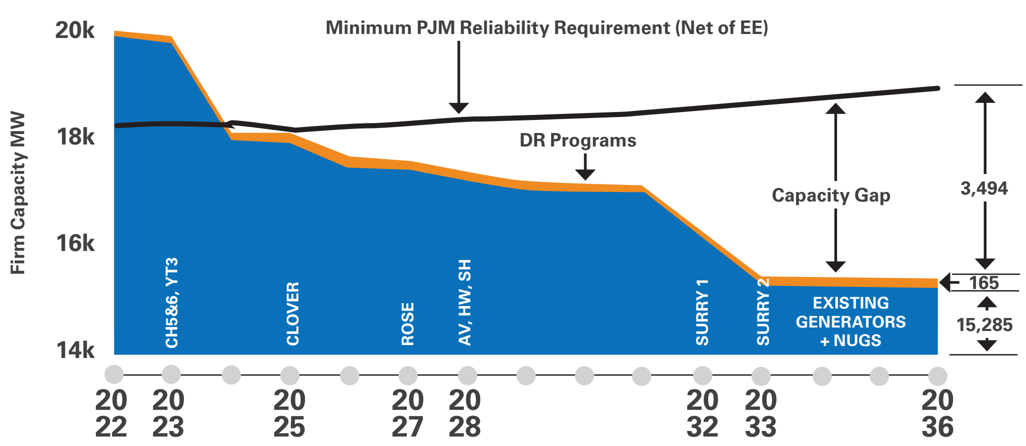
Gaston Hydro Station; Thelma, NC.

Based on the developments discussed above, and consistent with the requirements of the SCC and the NCUC, the Company has made adjustments to the type and size of resources identified in the 2020 Plan. As always, the Company's options for meeting these future needs are: (i) supply-side resources, (ii) demand-side resources, and (iii) market purchases. A balanced approach—which includes the consideration of options for maintaining and enhancing electric rate stability, increasing energy independence, promoting economic development, incorporating input from stakeholders, and minimizing adverse environmental impact—will help the Company meet growing demand and achieve its clean energy goals while protecting customers from a variety of potential challenges.

Capacity and Energy Positions

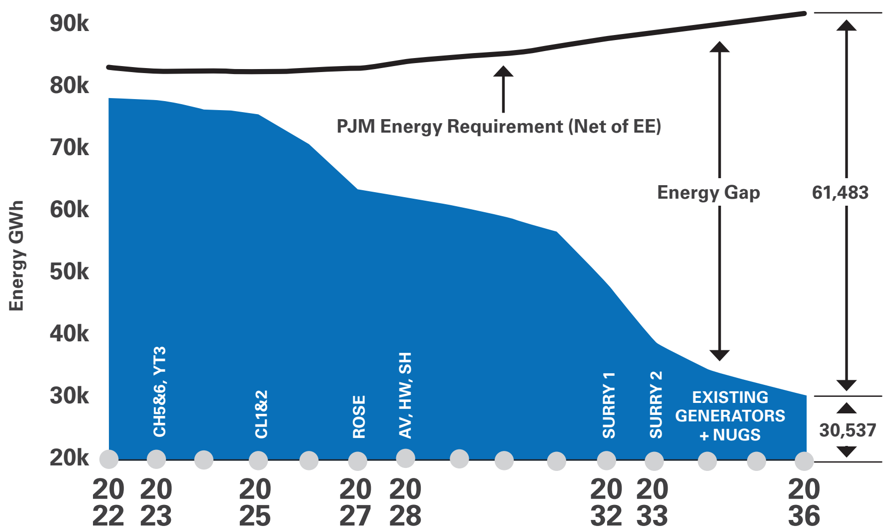
Figures 2.1.1 and 2.1.2 represent the Company's current capacity and energy positions using unit retirement assumptions in Alternative Plan B.

Figure 2.1.1: Current Company Capacity Position (2022 to 2036)



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.1.2: Current Company Energy Position (2022 to 2036)



Notes: "Existing Generators + NUGS" also include generation under construction; "EE" = energy efficiency;; "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass; "HW" = Hopewell; "SH" = Southampton (biomass).

Alternative Plans

The 2021 Update presents alternatives representing paths forward for the Company to meet the future capacity and energy needs of its customers, consistent with the 2020 Plan. Notably, more planning work is ongoing and necessary to test the grid under different conditions to ensure system reliability and security in the long term.

Specifically, the Company presents three Alternative Plans designed to meet customers' needs in the future under different scenarios, which were designed using constraint-based least-cost planning techniques:

Plan A: This Alternative Plan presents a least-cost plan that estimates future generation expansion while meeting applicable carbon regulations and the mandatory RPS Program requirements of the VCEA. Plan A is presented in compliance with SCC and NCUC orders and for cost comparison purposes only. For this Alternative Plan, the Company did not force the model to select any specific resource or exclude any reasonable resource and allowed the model to optimize the accompanying resource plan. Notably, Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.

Plan B: This Alternative Plan sets the Company on a trajectory toward dramatically reducing greenhouse gas emissions, taking into consideration future challenges and uncertainties. Plan B includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves natural gas-fired generation to address future system reliability, stability, and energy independence issues.[6] Over the Study Period, this Alternative Plan includes the development of nearly 18 gigawatts ("GW") of solar capacity, approximately 5 GW of offshore wind capacity, and approximately 2.7 GW of new energy storage.

Plan C: This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045 resulting in zero CO_2 emissions from the Company's fleet in 2046. If the Company retires all carbon-emitting units by the end of 2045, approximately 10 GW of new incremental battery storage would be needed to continue to reliably meet customer load. For context, the Company currently has approximately 100 MW of energy storage under development, in addition to its 16 MW of pilot projects. Over time as more renewable

[6] The natural gas resources preserved in Alternative Plan B differs from the 2020 Plan for two primary reasons: (i) Alternative Plan B no longer includes a 970 MW placeholder to address system reliability issues, and (ii) Rosemary is no longer classified as a natural gas unit.

energy and storage resources are added to the system, the Company will learn if Plan C is capable of maintaining a reliable system.

All Alternative Plans include Virginia's participation in RGGI, utilize the load forecast prepared by PJM, and assume a capacity factor for all existing and future solar resources of 21.2%, which is the 3-year average of solar tracking facilities in Virginia, as required. In addition, Alternative Plans B and C incorporate the social cost of carbon, as discussed in ***Social Cost of Carbon***.

Figures 2.2.1 through 2.2.3 show the build plans for each Alternative Plan. See Appendix 2A for the capacity, energy, and RECs associated with all Alternative Plans. See Appendix 2B for the capacity-related information directed by the SCC.

Figure 2.2.1: Alternative Plan A (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2021	20	15							
2022	62	416							
2023		307							CH5&6, YT3, VCHEC, AV, HW, SH
2024								900	
2025								1,000	
2026						485		600	
2027						485		300	
2028								400	
2029								500	
2030								500	
2031								600	
2032							Surry 1	700	
2033							Surry 2	800	
2034								900	
2035								1,000	
2036								1,000	
TOTAL	**82**	**738**	**-**	**-**	**-**	**970**	**1,676**	**9,200**	**2,567**

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources, whether Company-owned or PPA; "OSW" = offshore wind; "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.2.2: Alternative Plan B (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2021	20	15							
2022	62	416	52		20				
2023	746	317	102		83				CH5&6, YT3
2024	468	252	100		90				
2025	663	357	120		120				CL1&2
2026	663	357	120	2,587	120				
2027	663	357	120		150				Rosemary
2028	624	336	100		180				AV, HW, SH
2029	624	336	100		300				
2030	663	357	80		240				
2031	624	336	60		240				
2032	624	336	60		300		Surry 1		
2033	624	336	40	2,587	300		Surry 2		
2034	624	336	20		330				
2035	702	378	20		240				
2036									
TOTAL	8,394	4,822	1,094	5,174	2,713	-	1,676	-	2,561

"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources, whether Company-owned or PPA; "OSW" = offshore wind; "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 2.2.3: Alternative Plan C (nameplate MW)

Year	Solar COS	Solar PPA	Solar DER	OSW	Battery Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2021	20	15							
2022	62	416	52		20				
2023	746	317	102		83				CH5&6, YT3
2024	468	252	100		90				
2025	663	357	120		120				CL1&2
2026	663	357	120	2,587	120				
2027	663	357	120		150				Rosemary
2028	624	336	100		180				AV, HW, SH
2029	624	336	100		300				
2030	663	357	80		240				
2031	624	336	60		240				
2032	624	336	60		510		Surry 1		
2033	624	336	40	2,587	480		Surry 2		
2034	624	336	20		510				
2035	702	378	20		450				
2036					300				
TOTAL	8,394	4,822	1,094	5,174	3,793	-	1,676	-	2,561

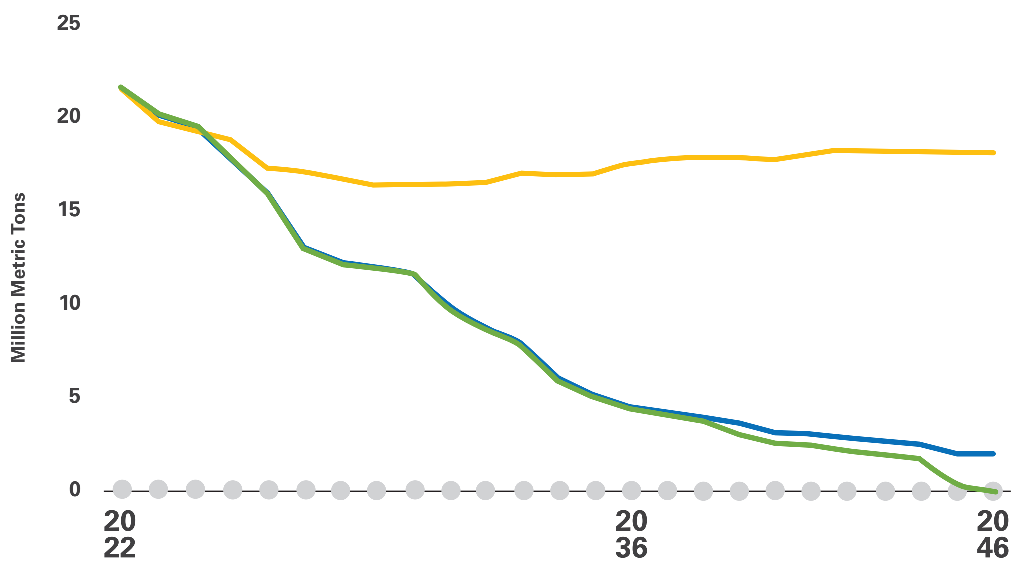
"COS" = cost of service; "PPA" = power purchase agreement; "Solar DER" = solar distributed energy resources, whether Company-owned or PPA; "OSW" = offshore wind; "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

A difference from the 2020 Plan is that Alternatives Plans B and C no longer include 970 MW of natural gas-fired combustion turbines as a placeholder to address system reliability issues resulting from the addition of significant renewable energy resources and the retirement of synchronous generator facilities. Associated reliability analyses are complex, under development, and still ongoing, as discussed in ***Transmission System Reliability Analysis.*** Future Plans will be updated, as needed, based on the results and findings of these reliability analyses.

As seen in Figures 2.2.2 and 2.2.3, Plans B and C are very similar over the first 15 years of the Planning Period. This alignment between Plans B and C suggests a common pathway for the Company to pursue now while allowing new technologies to emerge and mature and allowing analysis and study to continue.

Figure 2.2.4 shows projected CO_2 emissions from the Company's fleet for the duration of the Study Period.

Figure 2.2.4 – System CO_2 Output from Company Fleet for Alternative Plans



System CO_2 Emissions

	2036	2046
Plan A	18	18
Plan B	5	2
Plan C	4	0

Transmission System Reliability Analysis

In the 2020 Plan, the Company provided an initial overview of the reliability analyses that it would need to perform to investigate the probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of synchronous generator facilities. This included commitments to:

- Analyze impacts associated with the loss of traditional synchronous generators as well as the impacts of inverter-based generation at varying levels above and below their capacity factors. These impacts include the changes in system characteristics, such as inertia and frequency control, short-circuit system strength, power quality, reactive resources and voltage control, and system restoration and black start capabilities.
- Research the capabilities of inverter-based resources to provide needed system characteristics.
- Study the probability and impact of concurrent periods of generation excesses and deficits between the DOM Zone in PJM and neighboring regions.

These newer reliability concerns and issues are actively under study and development by the Company, and include the traditional reliability concerns that are also essential to continue to study. These include North American Electric Reliability Corporation ("NERC") Reliability Standard criteria and violations, PJM reliability criteria, existing Company criteria, thermal loading issues, voltage issues, and more. In addition to investigating these newer and traditional reliability issues, the Company is also investigating solutions, which include existing and new technologies, that may be needed to address these reliability issues in the future. Existing technologies include — transmission substations, transmission lines, synchronous generators, transformers, capacitor banks, reactor banks, static var compensators, and static synchronous compensators. Some of the new technologies the Company is investigating include: advanced grid monitoring and control capabilities; energy storage technologies; flexible alternative current transmission system ("FACTS") devices, such as high-voltage direct current ("HVDC"), and synchronous condensers; grid-forming inverters; high-capacity transmission substation and line technology; and advanced software and computational hardware for modeling, simulations, and analytics.

Over the past year, the Company has continued to work on these long-term modeling and analysis efforts in order to ensure the future reliability and resiliency of the grid. For example, the Company has been developing new system models for future years, studying areas of the system with large load increases expected, evaluating new renewable energy generation interconnection projects, and developing new methodologies and tools to study the new reliability issues and concerns. The Company has also been testing new simulation software platforms and researching new grid technologies and solutions, including grid forming inverters, energy storage technology, and synchronous condensers.

Net Present Value Comparison

The Company evaluated the Alternative Plans to compare and contrast the NPV utility costs for each build plan over the Study Period. Figure 2.4.1 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.

Figure 2.4.1: NPV Results ($B)

	Plan A	Plan B	Plan C
Total System Costs[1]	$32.5	$52.7	$55.4
Grid Transformation Plan (Net of Benefits)	$0.2	$2.0	$2.0
Strategic Underground Program	$1.9	$1.9	$1.9
Transmission Underground Pilots	$0.1	$0.1	$0.1
Transmission	$9.2	$9.2	$9.2
Other Capital	$2.1	$2.1	$2.1
Total Plan NPV[2, 3]	**$46.0**	**$67.9**	**$70.7**
Plan Delta vs. Plan A	**NA**	**$22.0**	**$24.7**

Notes: As previously ordered by the SCC, this figure includes incremental cost estimates associated with transmission and distribution investments.
(1) Total system costs include the results from Figures 2.2.1 through 2.2.3 plus approved, proposed, future, and generic DSM; costs related to environmental laws and regulations; renewable energy integration costs; and REC purchases and sales.
(2) All NPVs are calculated with a 6.46% discount rate.
(3) Numbers may not add due to rounding.

Consolidated Bill Analysis

The Company completed a consolidated bill analysis for each Alternative Plan presented in the 2021 Update. This analysis encompasses three different customer classes and spans 2021 through 2035.

The Company calculated projected bills for each customer class under each Alternative Plan based on requirements set by the SCC ("Directed Methodology"). These requirements dictate that the Company use constant class allocation factors across time and no sales growth, either at the system or class level, in its calculations. As discussed in prior proceedings, the Company believes that this methodology results in overstated bill projections because it does not reflect anticipated growth in sales over the 15-year period on which each build plan is based.

Under the Directed Methodology, all Alternative Plans also assume a capacity factor for existing and future solar resources of 21.2%—the 3-year average of solar tracking facilities in Virginia. As discussed in prior proceedings, the Company believes that a projected capacity factor for future solar facilities better reflects their long-term output and has therefore incorporated such capacity factors into one of the sensitivities presented in ***Sensitivity Analyses***.

Given these concerns with the Directed Methodology, the Company has also calculated projected bills under each Alternative Plan using (i) forecasted system and class sales growth, and the associated class allocation factors and (ii) a 25.4% capacity factor for solar resources ("Company Methodology").

The electric bill of the Company's typical residential customer in Virginia (i.e., one which uses 1,000 kWh per month) was $122.66 as of December 31, 2019. As of May 1, 2020, this typical bill was $116.18, with the decrease largely attributable to a significant reduction in the fuel factor. Figure 2.5.1 presents the summary results of typical residential customer bill projections under both the Company Methodology and the Directed Methodology based on Alternative Plan B for 2030 and 2035.

Figure 2.5.1 shows that, when using the Company Methodology and a baseline of May 1, 2020, the typical residential customer's bill is expected to increase at a compound annual growth rate ("CAGR") of 2.5% over the next 15 years. When using the Company Methodology and December 31, 2019 as the baseline, the projected increase in the typical residential customer's bill is approximately 2.1% on a compound annual basis.

As an additional point of comparison, in July 2008—the year following passage of the Virginia Electric Utility Regulation Act—the electric bill of the Company's typical residential customer in Virginia was $107.20. Using 2008 as the baseline, the projected CAGR for the typical residential customer bill through 2035 is approximately 1.8% using the Company Methodology.

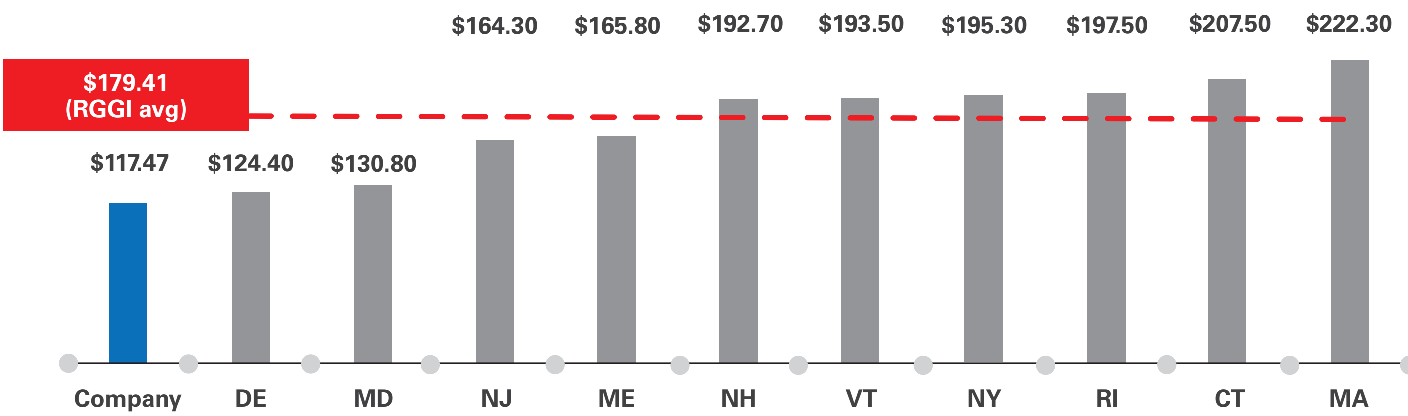
Figure 2.5.1: Residential Bill Projection
(1,000 kWh per Month)

	Plan B – Company Methodology[1]			Plan B – Directed Methodology		
	Projected Bill	CAGR Dec 2019	CAGR May 2020	Projected Bill	CAGR Dec 2019	CAGR May 2020
12/31/19	$122.66			$122.66		
05/01/20	$116.18			$116.18		
05/01/21	$117.47			$117.47		
Year End 2030	$163.13	2.6%	3.2%	$177.89	3.4%	4.1%
Year End 2035	$171.05	2.1%	2.5%	$199.35	3.1%	3.5%
Total Bill Increase *(May 2020-2035)*	$54.87			$83.17		

Note: (1) Derived using the system resources selected in Alternative Plan B incorporating the Company Methodology for the purposes of the billing analysis, including forecasted sales growth, forecasted class allocation factors, and a 25.4% capacity factor for solar resources.

For perspective, the average bill for residential customers in states participating in RGGI, normalized for 1,000 kWh monthly usage, is approximately $179.41 based on federal data. The Company's typical residential bill as of May 1, 2021 (i.e., $117.47) compares favorably to this benchmark, as shown in Figure 2.5.2.

Figure 2.5.2 – Residential Bill Comparison for RGGI States[1]



Note: (1) Based on residential rate data for RGGI states from U.S. Energy Information Administration as of June 2021, normalized for 1,000 kilowatt-hour monthly usage. Typical 1,000 kilowatt-hour residential bill for Company uses rates in effect May 1, 2021.

Sensitivity Analyses

The Company conducted several sensitivities for this 2021 Update on Alternative Plan B to show the potential paths forward under different future conditions consistent with SCC and NCUC requirements. For some sensitivities, the Company re-optimized the build plan. For others, the Company kept the same build plan as for Plan B but then applied different assumptions.

The Company re-optimized the build plan using different load forecasts. As discussed above, Alternative Plan B utilizes the 2021 PJM Load Forecast. While the Company believes that this load forecast understates the load growth in the Company's service territory as discussed in ***PJM Load Forecast***, the Company increased and decreased the 2021 PJM Load Forecast by 5% to show the build plans under high and low load forecast scenarios. The Company also ran a sensitivity using the 2021 Company Load Forecast. Finally, the Company ran a case reflecting only proposed or approved DSM programs as required by the SCC.

Figure 2.6.1 shows the results of these sensitivities.

Figure 2.6.1: 2021 Update Sensitivities Table on Load Forecast

	Plan B (PJM Load Forecast)	Plan B with PJM High Load Forecast	Plan B with PJM Low Load Forecast	Plan B Company Load Forecast	Plan B Existing Energy Efficiency
NPV Total ($B)	$67.9	$69.8	$66.0	$78.3	$67.1
Approximate CO_2 Emissions from Company in 2046 (Metric Tons)	2 M	2 M	2 M	2 M	2 M
Solar (MW)	14,310 15 yr. 17,790 25 yr.	14,310 15 yr. 18,570 25 yr.	14,310 15 yr. 14,090 25 yr.	14,728 15 yr. 24,508 25 yr.	14,310 15 yr. 18,448 25 yr.
Wind (MW)	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,174 25 yr.	5,174 15 yr. 5,174 25 yr.
Storage (MW)	2,713 15 yr. 2,773 25 yr.	2,713 15 yr. 2,773 25 yr.	2,713 15 yr. 2,773 25 yr.	2,713 15 yr. 2,773 25 yr.	2,713 15 yr. 2,773 25 yr.
Natural Gas-Fired (MW)	— 15 yr. — 25 yr.	— 15 yr. — 25 yr.	— 15 yr. — 25 yr.	— 15 yr. — 25 yr.	— 15 yr. — 25 yr.
Retirements (MW)	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 4,792 25 yr.	2,561 15 yr. 4,792 25 yr.

The Company also ran input variations on Alternative Plan B to show the effect on NPV using a range of possible costs. First, the Company ran a sensitivity using different commodity price forecasts. To provide sensitivities on fuel, energy, capacity and REC prices, the Company used two commodity price forecasts produced by ICF: the RGGI + Federal CO_2 High Fuel Price commodity forecast and the RGGI + Federal CO_2 Low Fuel Price commodity forecast. See ***Commodity Price Assumptions*** for a description of these forecasts and the interrelated nature of these commodity prices. Second, the Company ran a sensitivity that increased and decreased the projected capital construction costs of different resources by 10%. Third, the Company ran a sensitivity that used a projected design solar capacity factor of 25.4% instead of the three-year historical average capacity factor. As discussed in prior proceedings, the Company believes design capacity factor, which represents an average capacity factor over the life of the facility (i.e., not just three years), taking into account degradation, is a better reflection of long-term output for tracking solar facilities. Notably, however, the 3-year average capacity factor for solar units has increased by more than 2% since last year, moving closer to the anticipated design capacity factor of 25.4% for tracking solar facilities. Figure 2.6.2 shows the summarized results.

Figure 2.6.2: 2021 Update Sensitivities on NPV Costs

Plan Description	NPV Total (SB)
Plan B	$67.9
Plan B: High Fuel Market Prices	$77.9
Plan B: Low Fuel Market Prices	$66.9
Plan B: High Capital Construction Costs	$70.6
Plan B: Low Capital Construction Costs	$65.2
Plan B: 25.4% Solar Capacity Factor	$67.5

We continue to invest in high-voltage transmission assets to strengthen grid reliability to our electric customers.

Our Company

Short-Term Action Plan

Dominion Energy's Coastal Virginia Offshore Wind Project.

The short-term action plan provides the Company's strategic plan for the next five years (2021 to 2026). Generally, the Company plans to proactively position itself in the short-term to meet its commitment to clean energy for the benefit of all stakeholders over the long term. The Company also plans to continue its analyses on how to meet its clean energy goals while continuing to provide safe and reliable service to its customers.

Generation

Over the next five years, the Company expects to take the following actions related to existing and proposed generation resources:

- File annual plans for the development of solar, onshore wind, and energy storage resources consistent with the RPS Program requirements established by the VCEA, including related requests for approval of certificates of public convenience and necessity and for prudence determinations related to PPAs;
- Continue development and begin construction of a larger build-out of offshore wind off the coast of Virginia;
- Meet its targets under Virginia's mandatory RPS Program standard program at a reasonable cost and in a prudent manner, and submit its annual compliance certification to the SCC beginning in 2022;
- Meet its target 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;
- Support ongoing NRC review of the subsequent license renewal application submitted for North Anna Units 1 and 2 in August 2020;
- Continue to make investments at existing generation units needed to comply with environmental regulations; and
- Continue to evaluate potential unit retirements in light of changing market conditions and regulatory requirements.

Appendices 3A and 3B provide further details on each generation project under construction and under development, respectively.

Demand-Side Management

Over the next five years, the Company will continue to identify and propose new or revised DSM programs that meet the existing requirements of the Grid Transformation and Security Act of 2018 ("GTSA") and the requirements and targets in the VCEA in conjunction with the DSM stakeholder process. The Company also expects to complete a new market potential study in late 2021 and is currently working with an external consultant, Cadmus, and stakeholders towards development of a long-term DSM strategy and plan that will be filed with its 2021 DSM proceeding.

In Virginia, the Company filed its Phase IX DSM application in December 2020 seeking approval of 11 DSM programs. The SCC must issue its final order on this application in September 2021.

In North Carolina, the Company will continue its analysis of future programs and will file for approval in North Carolina of those programs that have been approved in Virginia and that continue to meet Company requirements for new DSM resources. For programs that are not approved by the SCC, the Company will evaluate the programs on a North Carolina-only basis.

Transmission

Over the next five years, the Company will continue to assess its transmission system and to construct facilities required to meet the needs of its customers. Generally, the Company anticipates transmission projects that are needed to rebuild aging infrastructure, and to interconnect data center customers and new renewable energy projects. Appendix 3D provides a list of planned transmission projects during the Planning Period, including projected cost per project as submitted to PJM. Appendix 7A lists the transmission lines under construction.

The Company will also continue its work to investigate the transmission system reliability issues resulting from the addition of significant renewable energy resources and the retirement of synchronous generator facilities, as discussed in ***Transmission System Reliability Analysis***.

Distribution

Over the next five years, the Company will continue to assess its distribution system, adapt the distribution grid to meet the needs of a modernized system, and implement solutions and programs to meet the needs of its customers both today and in the future. Specifically, the Company expects to take the following actions related to its distribution system:

- Continue implementing the Grid Transformation Plan, including initiatives to facilitate the integration of DERs, enhance distribution grid reliability and security, and improve the customer experience;
- Continue publishing hosting capacity maps for both utility-scale and net metering DERs;
- Continue to develop integrated distribution planning capabilities, including a standardized screening process to consider non-wires alternatives for distribution grid support;
- Continue its Strategic Undergrounding Program ("SUP");
- Pilot vehicle-to-grid ("V2G") technology through the Electric School Bus Program;
- Pilot battery energy storage systems ("BESS") as grid support and resiliency resources; and
- Expand its rural broadband program to bridge the digital divide and serve the unserved.

Our Company

Planning Assumptions

Brandon Aycock shares how Zero Emissions Vacuum and Compression (ZEVAC®) technology will be used to capture and recycle natural gas during maintenance and inspection activities in Apex, NC.

The Company's generation planning process for this 2021 Update is consistent with the process described in Chapter 4 of the 2020 Plan. Consistent with its established process, the Company has updated its assumptions for this 2021 Update to maintain a current view of relevant markets, the economy, and regulatory drivers as of the date of this filing. The sections that follow focus on the primary input assumptions that have changed since the 2020 Plan.

Load Forecast

The 2021 PJM Load Forecast was used in the development of all Alternative Plans. Because of the limited nature of the information available from PJM and the issues discussed in ***PJM Load Forecast***, the Company also presents and discusses the 2021 Company Load Forecast and presents a sensitivity using the Company Load Forecast, shown in ***Sensitivity Analyses***.

As with the 2020 Plan, the load forecasts in the 2021 Update include a downward post-model adjustment for both energy efficiency and retail choice, as described further in ***Energy Efficiency Adjustment*** and ***Retail Choice Adjustment*** below. The 2021 Update includes an adjustment for voltage optimization as part of the generic energy efficiency adjustment described further in ***Energy Efficiency Adjustment***.

Figures 4.1.1 and 4.1.2 compare the PJM Load Forecast with the Company Load Forecast for both 2020 and 2021; as can be seen, the 2021 PJM Load Forecast dropped dramatically. As discussed in ***PJM Load Forecast***, the material changes to PJM's Load Forecast and underlying methodology lead the Company to believe that it does not represent a realistic long-term forecast for use in system planning.

Figure 4.1.1: DOM LSE Non-Coincident Peak Load Forecast Comparison

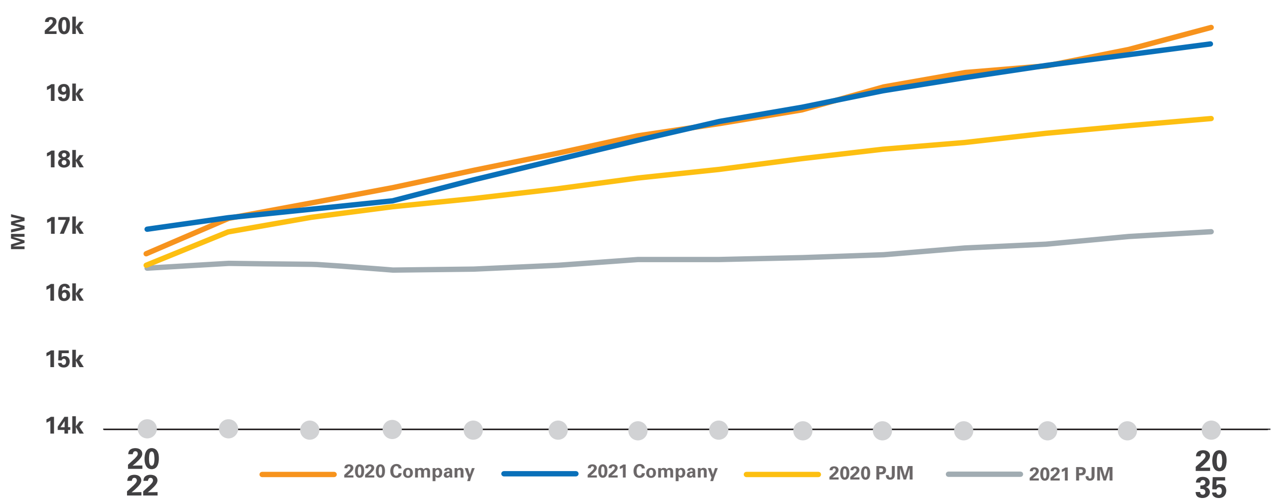
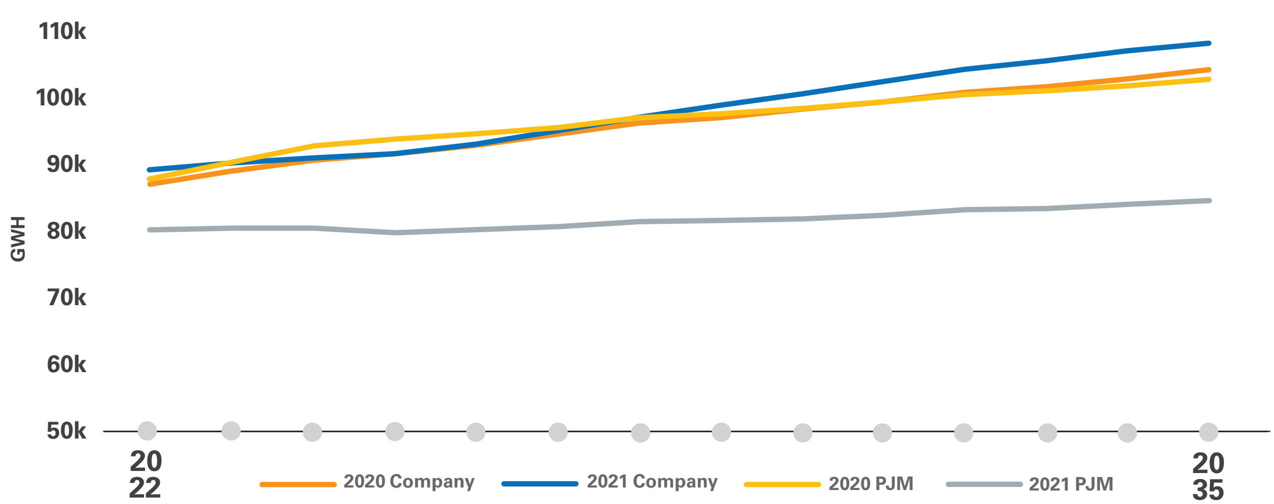


Figure 4.1.2: DOM LSE Annual Energy Comparison



Notably, both the 2021 PJM Load Forecast and the 2021 Company Load Forecast implicitly incorporate the effects on load of the ongoing public health emergency related to the spread of COVID-19 by way of the economic variables such as actual and forecast gross domestic product and employment.

PJM Load Forecast

For the 2021 Update, the Company used the same methodology as in the 2020 Plan to perform a downward adjustment on the 2021 PJM Load Forecast (published in January 2021) for the DOM Zone in order to arrive at the DOM LSE level. Chapter 4.1.1 of the 2020 Plan describes that process. Figure 4.1.1.1 presents the adjusted 2021 PJM Load Forecast. Overall, the PJM Load Forecast anticipates that summer peak demand and energy for the DOM Zone will increase at CAGR of approximately 0.9% and 0.6%, respectively, between 2021 and 2036.

PJM considers the DOM Zone to be a winter peaking zone. In other words, the winter peak demand forecast for the DOM Zone exceeds the summer demand peak in all years of the forecast period according to PJM. Given that the PJM regional transmission organization is still a summer peaking entity, however, PJM will continue to procure capacity for the DOM Zone at levels commensurate with the DOM Zone coincident summer peak forecast. As such, the Company developed this 2021 Update using a summer peak to align with PJM's DOM Zone summer coincident peak demand and energy forecast.

Springfield Solar Farm; Springfield, VA.

Figure 4.1.1.1: 2021 PJM Load Forecast Adjusted to LSE Requirements

Year	DOM Zone Coincident Peak (MW)	DOM LSE Equivalent (MW)	DOM Zone Energy (GWh)	DOM LSE Equivalent (GWh)
2021	19,540	15,875	100,235	80,026
2022	19,648	15,904	100,894	80,314
2023	19,903	15,983	101,716	80,361
2024	20,109	15,995	102,843	80,427
2025	20,302	15,910	103,369	79,948
2026	20,367	15,940	103,897	80,336
2027	20,449	15,998	104,415	80,734
2028	20,532	16,081	105,191	81,368
2029	20,568	16,086	105,450	81,574
2030	20,607	16,114	105,826	81,888
2031	20,682	16,166	106,456	82,403
2032	20,776	16,258	107,429	83,209
2033	20,883	16,326	107,828	83,533
2034	20,992	16,417	108,489	84,089
2035	21,070	16,487	109,221	84,585
2036	21,129	16,559	110,156	85,087
2037	21,239	16,636	110,851	85,652
2038	21,350	16,735	111,551	86,219
2039	21,462	16,826	112,255	86,775
2040	21,574	16,928	112,964	87,321
2041	21,687	16,991	113,677	87,877
2042	21,800	17,082	114,394	88,453
2043	21,914	17,180	115,116	89,039
2044	22,029	17,297	115,843	89,628
2045	22,144	17,372	116,574	90,222
2046	22,260	17,466	117,310	90,818

Company Load Forecast

The Company made a few changes to its methodology as described in Chapter 4.1.2 of the 2020 Plan.

At a high level, the Company's load forecast is prepared using DOM LSE peak and energy data, adjusted by excluding data center loads and adding back behind-the-meter solar load. This is followed by post-processing forecast adjustments for data centers, behind-the-meter solar, and EVs. Additionally, as noted above, the Company includes a downward post-model adjustment for both energy efficiency and retail choice. Figure 4.1.2.1 presents the 2021 Company Load Forecast. Overall, the Company anticipates the DOM LSE summer peak demand and energy forecast CAGR of 1.2% and 1.4%, respectively.

The primary refinements that the Company has made to its internal load forecasting methodology since the 2020 Plan are:

- DOM LSE sales, energy, and peak are now modeled directly. In the 2020 Plan, the Company instead modeled the DOM Zone and then derived DOM LSE by utilizing a DOM LSE to DOM Zone ratio.
- DOM LSE peak load was derived using peak-to-energy ratios from the past ten years after taking out data center load. Derivation of DOM LSE peak using this approach, as opposed to modeling both peak and energy in isolation, promotes consistency and prevents abrupt changes in the resulting load factor from differences in two independent models.
- Usage per customer is modeled directly as opposed to modeling total residential sales and customer count. Residential sales are calculated as usage per customer multiplied by customer count. Modeling of usage per customer enables the Company to directly capture customer usage trends, housing characteristics, and efficiency trends embedded in historical data.
- Data center sales, energy, and peak demand are now being forecasted by the Company as a standalone category and are being applied to the Company's sales, peak, and energy forecasts as an exogenous adjustment. This action is consistent with a recommendation provided by Itron Inc., in its review of the Company's load forecasting methodology, as discussed in the 2020 Plan. The forecast utilizes a combination of internal forecasting through 2026 and declining growth rates for 2027 and beyond.

Figure 4.1.2.1: 2021 Company Load Forecast

Year	2021 Company Summer Peak Forecast (NCP) (MW)	2021 Company Energy Forecast (GWh)
2022	16,665	89,368
2023	16,757	90,421
2024	16,809	91,285
2025	16,787	91,783
2026	16,962	93,263
2027	17,233	95,199
2028	17,520	97,199
2029	17,792	99,096
2030	18,050	100,886
2031	18,315	102,662
2032	18,588	104,425
2033	18,797	105,806
2034	19,017	107,174
2035	19,220	108,385
2036	19,429	109,550
2037	19,566	110,277
2038	19,777	111,834
2039	19,989	113,412
2040	20,205	115,013
2041	20,422	116,637
2042	20,642	118,283
2043	20,864	119,952
2044	21,088	121,645
2045	21,315	123,362
2046	21,544	125,104

- The Company includes an adjustment to its sales, energy, and peak demand forecast to account for future incremental EV load. For this 2021 Update, the Company has revised its EV forecasting process. A separate EV forecast has been developed and added to energy, peak, and sales forecast as a post-model adjustment. The EV forecast was developed by utilizing an EV forecast from ICF, which in turn utilizes the NREL's Electrification Futures Study.

Energy Efficiency Adjustment

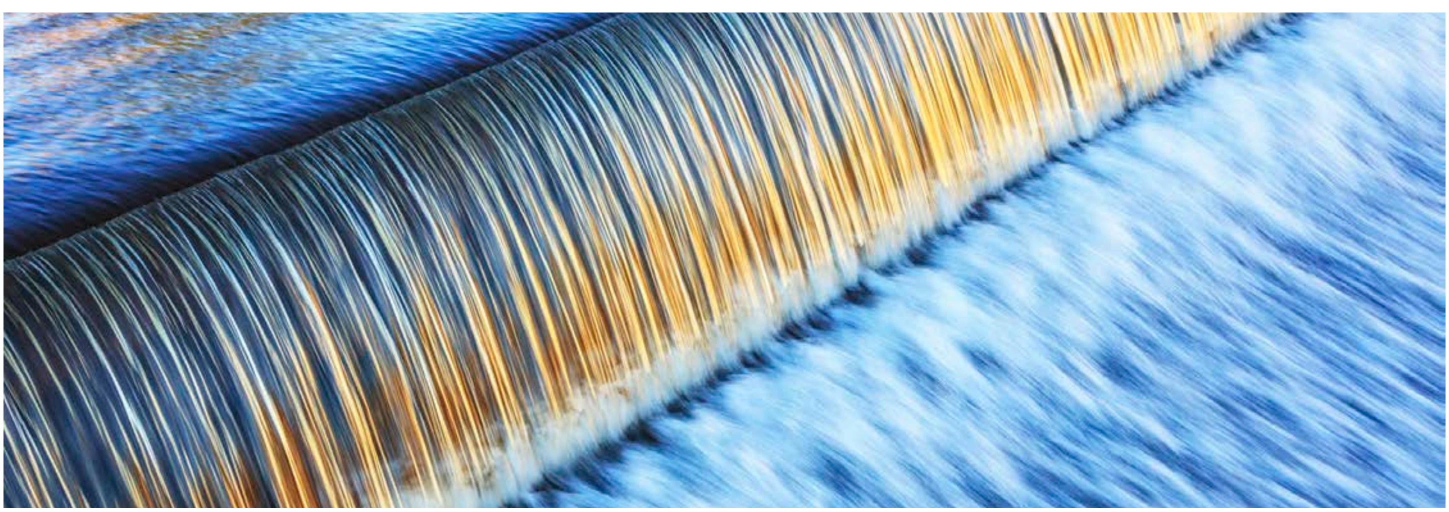
As with the 2020 Plan, the load forecasts in this 2021 Update include a downward post-model adjustment for energy efficiency ("EE"). The EE adjustment to the forecasts can be broken down into two distinct categories. The first category ("Category 1 Programs") consists of previously-approved EE programs that remain effective (i.e., that are still producing savings), along with programs that are currently pending approval before the SCC in Case No. PUR-2020-00274. The second category ("Category 2 Program" or "generic" EE) represents unidentified EE programs and measures designed to meet legislative directives. Specifically, the generic EE is designed to meet: (i) the energy savings targets in the VCEA for 2022 through 2025; (ii) a 5% energy savings target for 2026 and beyond; (iii) the GTSA requirement to propose $870 million in EE programs by 2028; and (iv) at least 15% of EE costs allocated to programs designed to benefit low-income, elderly, or disabled individuals or veterans.

Alternative Plan A includes only an adjustment for previously-approved and pending programs—the Category 1 Programs. Alternative Plans B and C also include the additional adjustment for generic EE—the Category 2 Program.

To estimate the generic EE, the Company reviewed the actual savings results and costs of its EE programs for 2012 through 2020 in order to develop an average cost per net kWh saved on a persistent savings basis (expressed as "$/kWh"). The Company analyzed the $/kWh as a total portfolio view, excluding low income and as a low-income only view. The total portfolio $/kWh, excluding low income, was calculated to be approximately $0.058/kWh (or $58/MWh), and the low income-only $/kWh was calculated to be approximately $0.253/kWh (or $253/MWh). The Company then applied the portfolio and low income $/kWh in the necessary quantities to meet the legislative directives noted above at the appropriate levels.

This approach is a theoretical assumption used for modeling purposes only. The actual costs and benefits of future EE will be dependent upon many factors, including the ability of future vendors to deliver program savings at the fixed price, customer participation, and the effectiveness of the program to be administered at that price.

Figures 4.1.3.1 and 4.1.3.2 on page 31 identify the EE energy and capacity adjustments to the load forecasts used in this 2021 Update, respectively.



Roanoke Rapids.

Figure 4.1.3.1: EE Energy Forecast Adjustment

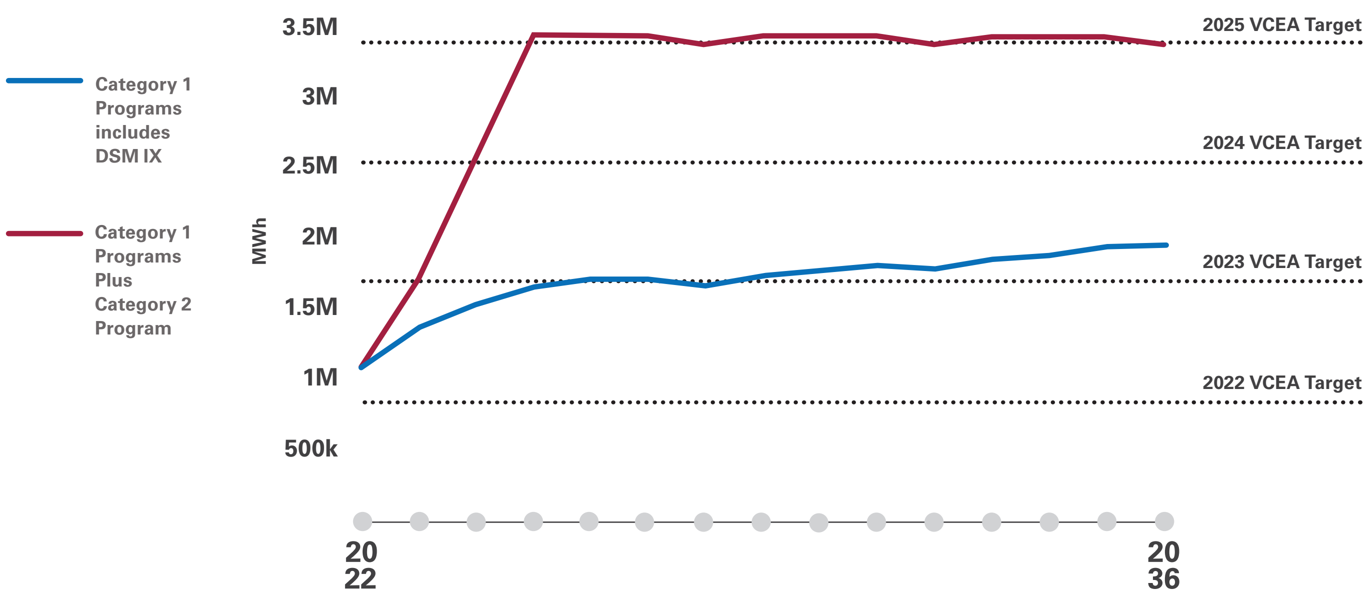
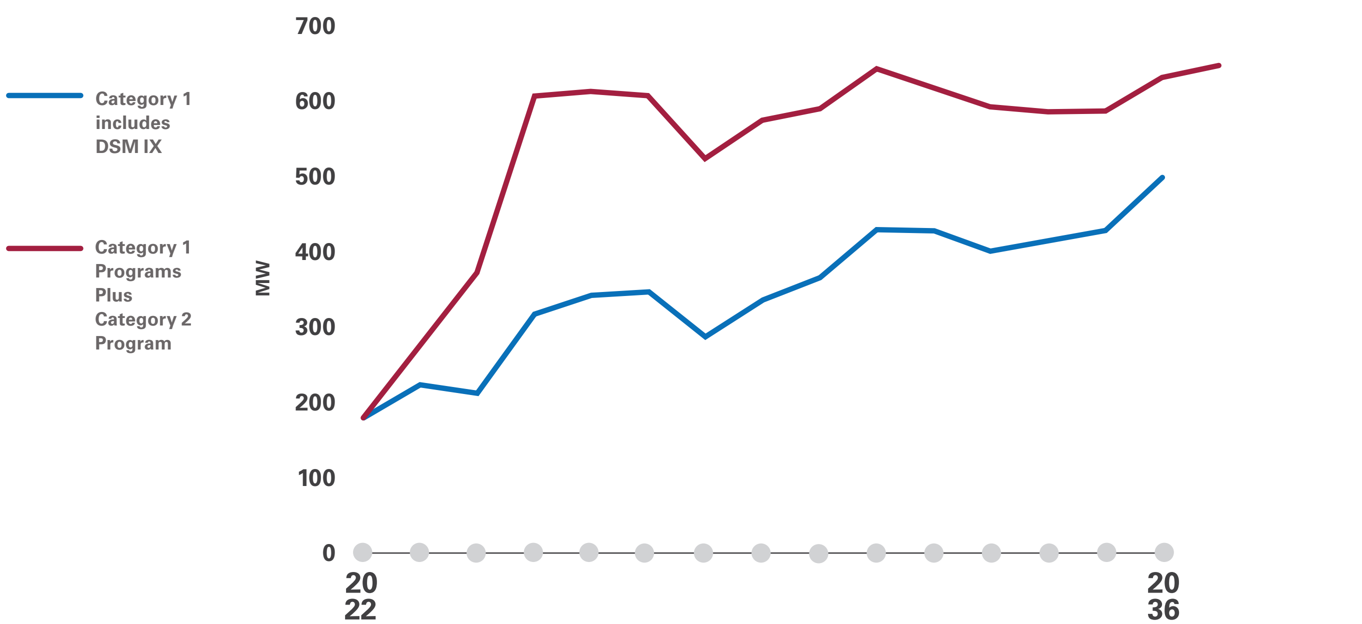


Figure 4.1.3.2: EE Coincident Summer Peak Demand Forecast Adjustment



Retail Choice Adjustment

For the 2021 Update, the Company used the same methodology described in Chapter 4.1.1 of the 2020 Plan to adjust the load forecasts for customers in the Company's service territory that have chosen (or may choose) to purchase energy and capacity from third-party electric suppliers under Va. Code § 56-577 ("Choice Customers"). The only additional assumption in the Company's calculation of future Choice Customer reduction in the 2021 Update is that the customers who elected retail choice during the year 2021 will continue to be served by a third-party electric supplier for the full year based on their actual usage history.

Capacity Value Assumptions

Since the fall of 2018, PJM has been developing a probabilistic analysis aimed at valuing the capacity value of renewable energy resources. This approach utilizes a concept called effective load carrying capability ("ELCC"). As defined by PJM, ELCC is a measure of the additional load that a particular generator of interest can supply without a change in reliability.

ELCC can also be defined as the equivalent MW of a traditional generator that results in the same reliability outcome that a particular generator of interest (such as an intermittent generator) can provide. The metric of reliability used by PJM is loss of load expectation, a probabilistic metric that is driven by the timing of high loss-of-load probability hours. Therefore, PJM states that a resource that contributes a significant level of capacity during high-risk hours will have a higher capacity value (i.e., a higher ELCC) than a resource that delivers the same capacity only during low-risk hours. "High-risk hours" are those hours during which PJM expects the peak demand to occur.

For the purposes of the 2021 Update, the Company utilized the preliminary PJM ELCC study published in March 2021 to estimate the capacity value of solar, offshore wind, and storage resources. This approach indicated the capacity value of solar is currently in the 54% range, decreasing over time as solar saturation grows. For offshore wind, the capacity value is currently in the 27% range, and decreases over time as offshore wind saturation grows. For storage, the Company is utilizing a capacity value of 79% for four-hour systems and 93% for eight-hour systems. PJM currently performs its ELCC calculations at the hourly or daily level. PJM published a new study in August 2021 that showed higher capacity values for offshore wind with little change to solar and storage. While this new study could not be incorporated into the 2021 Update, it will be reflected in future proceedings.

Coastal Virginia Offshore Wind Demonstration Project.

Commodity Price Assumptions

The Company utilizes a single source to provide multiple scenarios for the commodity price forecast to ensure consistency in methodologies and assumptions. The Company used the same methodology to blend the ICF commodity forecasts with forward market prices for certain commodities, as described in Chapter 4.4 of the 2020 Plan. The key assumptions on market structure and the use of an integrated, internally consistent fundamentals-based modeling methodology remain consistent with those utilized in the prior years' commodity forecasts.

In the 2021 Update, the Company utilized three commodity forecasts:

- RGGI + Federal CO_2
- RGGI + Federal CO_2 High Fuel Price
- RGGI + Federal CO_2 Low Fuel Price

These High and Low Fuel Price commodity forecasts utilize high and low natural gas supply scenarios from the United States Energy Information Administration to create high and low cases of natural gas fuel prices, as natural gas continues to be a dominant marginal source of generation in PJM over the time horizon in the base commodity case (i.e., the RGGI + Federal CO_2 commodity forecast).

A change in natural gas prices affects the energy price directly. That is, as natural gas fuel prices increase, energy prices increase. The energy price affects the revenue stream available to renewable energy generators, which in turn results in a change in REC price. In other words, as energy prices increase driven by higher fuel prices, REC prices generally decrease as a result of increased renewable build. Similarly, the capacity price is also directly influenced by the marginal sources of energy and is reflective of the net energy compensation requirements. In other words, as revenue available to renewable energy generators increases due to higher fuel prices, capacity prices decrease. Hence, the movement of natural gas prices will impact the resulting power market commodity prices directly and in a consistent manner across high and low scenarios.

In all three commodity forecasts, the CO_2 price forecast is consistent with the methodologies utilized in the 2020 Plan. In all forecasts, Virginia is a member of RGGI starting in 2021 and a charge on CO_2 emissions from the power sector at the federal level is assumed to begin in 2026.

The Company utilized the RGGI + Federal CO_2 commodity forecast for all Alternative Plans, and the High and Low Fuel Price commodity forecasts to run sensitivities, which are described in ***Sensitivity Analyses***. Appendix 4O provides the annual prices (in nominal dollars) for each commodity price forecasts. Figure 4.3.1 provides a comparison of the three commodity forecasts with the base commodity forecast used in the 2020 Plan.

Figure 4.3.1: 2020 Plan vs. 2021 Update Fuel, Power, and REC Price Comparison

	2021-2035 Average Value (Nominal $)	2022-2036 Average Value (Nominal $)		
Fuel Price	**2020 Mid Case CO_2 With VA in RGGI**	**2021 RGGI + Fed CO_2 Case**	**2021 RGGI + Fed CO_2 High Fuel Price Case**	**2021 RGGI + Fed CO_2 Low Fuel Price Case**
Henry Hub Natural Gas ($/MMbtu)	4.05	3.61	6.00	3.40
Zone 5 Delivered Natural Gas ($/MMbtu)	3.68	3.18	5.57	2.97
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	74.20	62.94	63.46	62.92
1% No. 6 Oil ($/MMbtu)	11.52	9.91	10.52	9.04
Electric and REC Prices				
PJM-DOM On-Peak ($/MWh)	44.58	35.11	50.60	33.94
PJM-DOM Off-Peak ($/MWh)	34.78	30.46	46.71	29.40
PJM Tier 1 REC Prices ($/MWh)	9.13	9.84	6.39	10.21
RTO Capacity Prices ($/kW-yr)	57.34	64.98	40.80	66.13

Renewable Energy-Related Assumptions

Solar Capacity Factor

For Alternative Plans A through C, the Company modeled existing and future solar resources using a capacity factor of 21.2%, which is the average capacity factor of the Company's owned solar tracking fleet in the Commonwealth for the most recent 3-year period (i.e., 2018, 2019, 2020), as required by prior SCC orders.

The Company also ran a sensitivity on Alternative Plan B using a capacity factor of 25.4% for future solar resources, which is the average design capacity factor representing an average capacity factor over the life of the facility (i.e., not just three years), taking into account degradation. The results of that sensitivity can be seen in ***Sensitivity Analyses***.

Solar Company-Build vs. PPA

In all Alternative Plans, the Company limited the model to selecting a maximum of 1,200 MW per year, which is based on an assumed amount of new solar generation available each year. For solar resources in Alternative Plan A, the Company allowed the model to select either Company-build cost-of-service solar or third-party PPA. For Alternative Plans B and C, the Company modeled solar PPAs as 35% of the solar generation capacity placed in service over the Study Period, which is consistent with the 2020 Plan and the VCEA.

Renewable Energy Interconnection and Integration Costs

As explained in Chapter 4.6.3 of the 2020 Plan, the Company incorporates assumptions regarding interconnection costs and integration costs into its long-term planning process. The solar integration costs include three categories of system upgrade costs based on different issues caused by the intermittent nature of renewable energy resources: transmission integration costs; generation re-dispatch costs; and regulating reserves.

In this 2021 Update, the Company has revised its assumptions and, in some instances, refined its methodology. Notably, in the 2020 Plan, the Company only applies these costs to solar resources; in this 2021 Update, the Company also applies these costs to wind resources.

Transmission Interconnection Costs. In this 2021 Update, the Company assumed renewable energy interconnection costs of \$89/kW for utility-scale solar facilities and \$310/kW for distributed solar facilities. Consistent with the 2020 Plan, the Company assumed \$0 in interconnection costs for solar PPAs because the PPA price from the developer includes interconnection costs.

Transmission Integration Costs. For transmission integration costs, the Company used the same methodology as in the 2020 Plan, updated to reflect the updated assumptions for interconnection costs noted above.

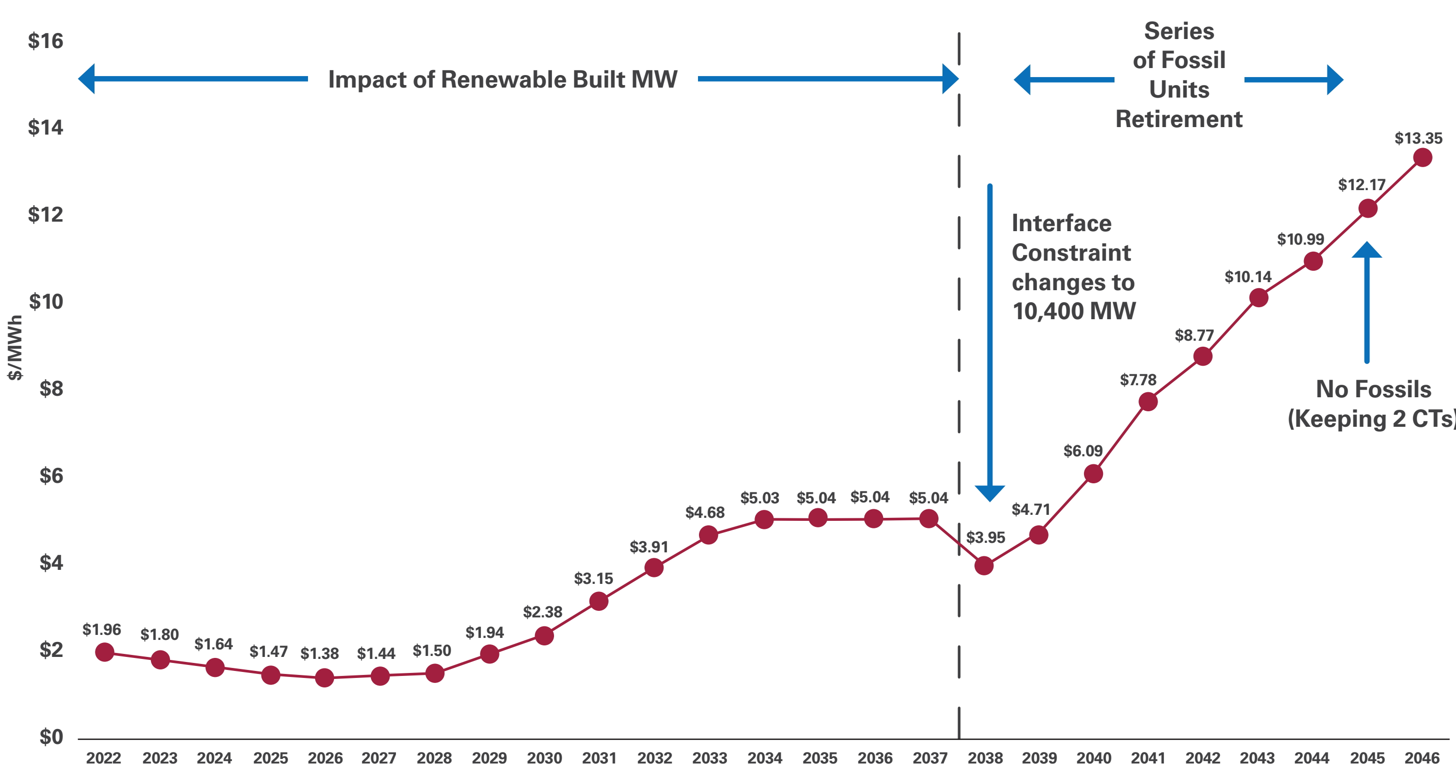
Generation Re-dispatch Costs. As explained in the 2020 Plan, re-dispatch generation costs are defined by the Company as additional costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. For the 2021 Update, improvements from the 2020 Plan were made to the variations on hourly generations to include solar and offshore wind generation, as well as to the methodology utilized in the generation re-dispatch cost analysis. For example, the Company took a chronological approach utilizing one build plan from the 2020 Plan (Alternative Plan D) with one fuel price set (2021 RGGI + Federal CO_2) and studied 16 years chosen based on when resources were introduced or retired in the build plan. For each simulation year, the Company performed a base case Aurora simulation by using the base hourly renewable generation profiles to establish the base case commitment decisions. Using these commitment decisions, the Company performed an additional 200 simulations but applied different hourly renewable profiles from NREL's historical weather patterns studies to reoptimize the system cost.

Southampton Solar Farm; Southampton, VA.

The total system cost for each simulation was compared to the base case system cost of the same year. This delta of the system cost is composed of the respective differences in fuel, variable operation and maintenance costs, emissions, purchase/sale of energy and power costs. The re-dispatch cost is the delta of the system cost divided by the Company's expected total renewable generation. Based on these results, the Company constructed a generation re-dispatch cost curve for the entire Study Period, as shown in Figure 4.4.3.1. These values were used as a variable cost adder for all renewable energy generation evaluated in this 2021 Update.

Over time, the re-dispatch costs are projected to increase due to: (i) the increase of fuel and CO_2 prices in the 2021 RGGI + Federal CO_2 case, which resulted in higher DOM Zone prices; (ii) the retirement of dispatchable fossil generating facilities; and (iii) the increased penetration of renewables causing an increase in energy imbalance (excess or shortage) to meet the load obligation. If the energy imbalance was due to excess energy, the sale price trended lower, even close to zero, which reduced the sales revenues. If the imbalance was due to an energy shortage, the purchase price could be as high as $1,000/MWh (PJM price cap). This extreme results in an increase in purchase costs.

Figure 4.4.3.1: Generation Re-dispatch Cost Results ($/MWh)



Regulating Reserve Costs. As described in the 2020 Plan, regulating reserves are defined as additional reserves needed to balance the uncertainty of forecast errors of net load that occur during a typical power system operational day. The methodology utilized in this 2021 Update is consistent with the 2020 Plan, but the analysis was updated with 2020 market information. Specifically, in 2020, the cost of regulating reserves averaged $0.22/MW, but the cost in specific hours ranged from $0.00 to over $73.00. The results of the analysis with these updated assumptions reflect that the hourly (per MW) cost of regulating reserves gradually increases from $0.52 in 2022, to $16.72 in 2046. This occurs because the rate that PJM is forecasted to increase the need for regulating reserves (driven by the level of renewable energy build) grows more quickly than the projected addition of resources that provide regulation reserves in PJM. Figure 4.4.3.2 to the right shows the net cost to customers included in this 2021 Update.

Least-Cost Plan Assumptions

Alternative Plan A presents a least-cost plan using assumptions required by the SCC. Specifically, Plan A uses the PJM Load Forecast adjusted for only existing and proposed energy efficiency. It meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA. As noted in ***PLEXOS Modeling Refinements***, the Company has refined PLEXOS to model the RPS Program, and allows the model to choose up to 100% of REC market purchases as needed to comply with the annual RPS Program requirements. For Plan A, the Company did not force the model to select any specific resources and did not exclude any reasonable resource options. That said, the model did include reasonable build constraints, including the 1,200 MW annual solar limit as well as a limit of one pair of simple cycle combustion turbines per year. The potential unit retirements shown in Plan A are those selected by PLEXOS, as discussed further in ***Existing Supply-Side Generation***.

Figure 4.4.3.2 – Company Net Regulating Reserves Cost of Market Purchases ($000,000)

Year	Plan A	Plan B	Plan C
2022	$0	$0	$0
2023	$0	$0	$0
2024	$0	$0	$0
2025	$0	$0	$0
2026	$0	$0	$0
2027	$0	$0	$0
2028	$0	$0	$0
2029	$0	$0	$0
2030	$0	$0	$0
2031	$0	$1	$1
2032	$0	$11	$11
2033	$0	$17	$0
2034	$0	$208	$174
2035	$0	$213	$163
2036	$0	$231	$161
2037	$0	$235	$137
2038	$0	$240	$113
2039	$0	$246	$88
2040	$0	$252	$19
2041	$0	$254	$0
2042	$0	$260	$0
2043	$0	$304	$0
2044	$0	$351	$0
2045	$0	$401	$0
2046	$0	$409	$0

Note: Zero values indicate that the DOM LSE has adequate regulating reserves to supply reserve requirements from the LSE's load and renewable generation portfolio that year.

Our Company

Chesterfield Power Station; Chester, VA.

This section provides an overview of the Company's existing supply-side generation and the Company's analysis of future supply-side generation to the extent there have been changes from the 2020 Plan.

Existing Supply-Side Generation

Appendix 5A provides information on the Company's existing supply-side resources. The Company continuously evaluates various options with respect to its existing fleet, cognizant of environmental regulations and other policy considerations.

For this 2021 Update, the Company updated its retirement analysis consistent with its prior practice and SCC orders. First, the Company completed a ten-year cash flow analysis focused on coal-fired, biomass-fired, and large combined cycle generation facilities under market conditions.

Similar to prior Plans, the Company evaluated 10 year cash flows under four scenarios using the RGGI + Federal CO_2 commodity projections as an underlying market forecast. 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 for the next ten years based on the snapshot in time when the analysis was conducted. 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 market, while a negative value indicates the unit is currently worse than market. These results alone are not comprehensive and cannot exclusively be used to determine 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, personnel, impact of continued operation of the unit(s) on the local economy, and environmental benefits, to name a few. The results of the ten-year cash flow analysis are included in Figure 5.1.1.

Figure 5.1.1: Ten-year Cash Flow Analysis Results (NPV $ Million)

Units	2021 Plan A	2021 Plan B	Low Capacity Price	High Capacity Price
Clover 1-2	$30	$24	($51)	$36
Mt. Storm 1-3	$60	($4)	($288)	$86
VCHEC	($357)	($381)	($483)	($347)
Altavista	($45)	($45)	($53)	($44)
Hopewell	($35)	($34)	($44)	($35)
Southampton	($44)	($43)	($53)	($43)
Rosemary	$32	$31	($3)	$35
Bear Garden	$149	$119	$9	$159
Brunswick	$648	$570	$336	$672
Chesterfield 7-8	$56	$24	($32)	$62
Gordonsville 1-2	$31	$22	($18)	$35
Greensville	$861	$779	$508	$888
Possum Point 6	$162	$134	$32	$172
Warren	$523	$445	$213	$547

Note: High and Low Capacity Price scenarios used Plan A's underlying assumptions.

Second, as directed by the SCC, the Company included the same unit specific data for the units listed in Figure 5.1.1 into PLEXOS to allow the model to optimize endogenously the timing of unit retirements. The Company presented these results as part of Alternative Plan A, which showed Altavista, Hopewell, Southampton, and VCHEC retiring in 2023, and all other units running through the Study Period.

In Alternative Plans B and C, consistent with prior Plans, the Company aimed to determine a glide path so as to continue to reliably serve customers through the transition to a cleaner energy fleet, taking into consideration components such as capacity factors, performance characteristics, including ramping time and maintenance requirements, and environmental regulations.

VCHEC entered commercial operation in July 2012, and is designed to burn coal, waste coal, and biomass. In addition to serving customers' energy and capacity needs, VCHEC supports jobs, economic development, and water quality improvements in the coalfield regions of Virginia. Based on these qualitative factors, the retirement of VCHEC was modeled in 2045 in Alternative Plans B and C. Altavista, Hopewell, and Southampton serve customers' energy and capacity needs while also producing renewable energy credits and production tax credits. In the short term these biomass units supply renewable energy for the Company's 100% renewable energy tariff, help the Company transition to a cleaner energy fleet, and support their local economies, such as the logging and trucking industries. Based on these factors, the retirement of the three biomass units was modeled in 2028 in Alternative Plans B and C in order to meet the VCEA biomass retirement date.

As noted in the 2020 Plan, the Company anticipates retiring Yorktown Unit 3 and Chesterfield Units 5 and 6 in 2023. Other than these units, inclusion of a unit retirement in this 2021 Update should be considered as tentative only based on a snapshot in time. The Company has not made any decision regarding the retirement of any generating unit other than Yorktown Unit 3 and Chesterfield Units 5 and 6. The Company's final decisions regarding any unit retirement will be made at a future date. Appendix 5J lists the generating units considered for potential retirement.

Future Supply-Side Resources

The Company followed a similar process for selecting alternative resource types as described in Chapter 5.5 of the 2020 Plan.

Supply-Side Resource Options

Figure 5.2.1.1 summarizes the resource types that the Company reviewed as part of this 2021 Update. Those resources considered for further analysis in the busbar screening model and PLEXOS are identified in the final columns.

Figure 5.2.1.1: Alternative Supply-Side Resources

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource	PLEXOS Resource
Aero-derivative Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Battery Generic (30 MW)(4H)	Peak	Yes	Varies	Yes	Yes
Battery Generic (30 MW)(8H)	Peak	Yes	Varies	Yes	Yes
Combined Cycle - 1X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 2X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 3X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Heat and Power	Peak	Yes	Varies	No	No
Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Fuel Cell	Baseload	Yes	Natural Gas	Yes	No
Nuclear Small Modular Reactor	Baseload	Yes	Uranium	Yes	No
Pump Storage (300 MW)	Peak	Yes	Renewable	Yes	Yes
Solar	Intermittent	No	Renewable	Yes	Yes
Solar (Distributed)	Intermittent	No	Renewable	Yes	Yes
Supercritical Pulverized Coal with CCS	Intermediate	Yes	Coal	Yes	No
Wind - Offshore	Intermittent	No	Renewable	Yes	Yes
Wind - Onshore	Intermittent	No	Renewable	Yes	Yes

Prior Plans provide details on the technologies listed in Figure 5.2.1.1. In the 2021 Update, the Company provides updates on two technologies—energy storage and advanced nuclear technologies.

Energy Storage. The term "energy storage" applies to a diverse set of technologies that can store energy at one time and make it available at another time. The technologies range in size, cost, performance characteristics, and application. Energy storage can support the grid in a number of ways, including improved reliability, increased resiliency, and operational flexibility.

Until recently, energy storage resources have not been broadly deployed at utility scale, other than pumped hydroelectric storage. There is increasing interest in additional pumped storage technology as a storage mechanism for the intermittent and highly variable output of renewable energy sources such as solar and wind. As discussed in the 2020 Plan, in 2017, the Company entered into the early stages of conducting feasibility studies for a potential pumped storage facility in the western part of Virginia. Pumped storage is a proven dispatchable technology that would complement the ongoing integration of renewable energy resources. The Company continues to evaluate the construction of a proposed pumped hydroelectric storage power station at a site in Tazewell County, Virginia.

In addition to legislation in recent years supporting pumped storage, the VCEA sets aggressive targets for the development of energy storage generally in Virginia to enhance the reliability and performance of the generation and distribution systems.

The Company presents its plan for the development of energy storage resources in the annual proceeding required by Va. Code § 56-585.5, including its progress to date on energy storage development. As stated in those plans, the Company intends to pursue additional energy storage resources, including opportunities to use energy storage for peak demand reduction and non-wires alternatives. Currently, the Company is evaluating a potential project to study storage paired with direct current fast charging infrastructure for EVs and another potential project aimed at understanding the ability of storage to provide backup power and resiliency for the Company's customers. While the Company believes that BESS (lithium-ion technology in particular) will be the dominant form of energy storage for the foreseeable future, the Company will also seek opportunities to expand its understanding of energy storage technologies by evaluating additional forms of energy storage, including long duration storage technologies and establish projects to deploy those technologies where technically and economically feasible. See SCC Case Nos. PUR-2020-00134 and PUR-2021-00146 for more information on the Company's approach to energy storage.

Advanced Nuclear Technologies. Advanced nuclear technologies are being evaluated by the Company as an additional technology to achieve net zero carbon and methane emissions. This includes SMRs, which offer an alternative to traditional nuclear technology. Given the dispatchable or load-following capabilities of SMRs, they may serve as a carbon-free complement to the large volumes of intermittent renewable generation that is expected to be deployed over the next 15 years. Among other benefits, SMRs may be built modularly and transported easily, which reduces the investment risk associated with traditional nuclear power. Their smaller size, modular components, and passive safety features make it possible to site them on brownfield sites such as retired fossil-fuel plants, existing nuclear sites that have operating plants, other industrial areas, or greenfield sites.

To further the advancement of innovative nuclear technologies, the United States Department of Energy is providing funding through programs under the new Advanced Reactor Demonstration Program. Additional financial incentives for advanced nuclear technologies were made available through the 2005 Energy Policy Act.

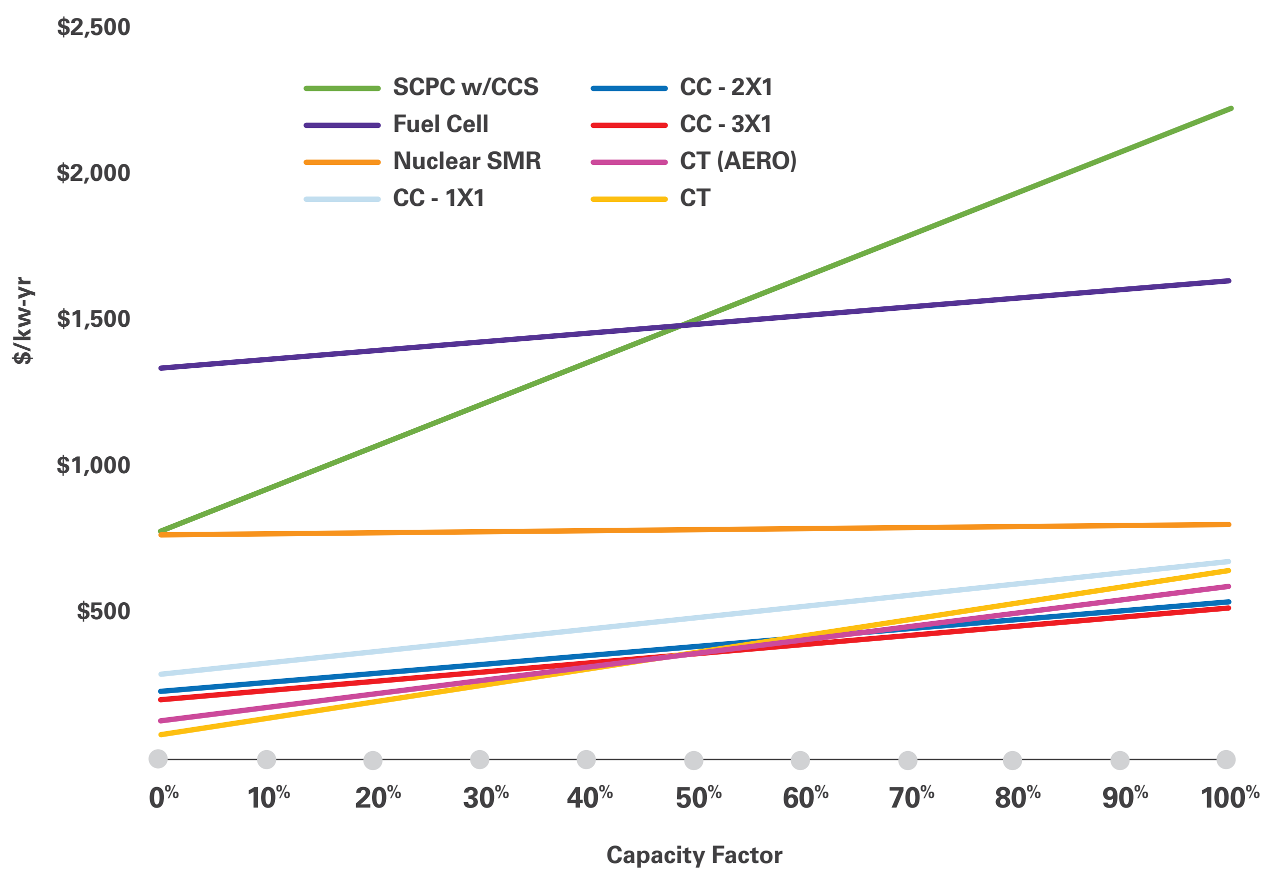
Although the technology has not yet been deployed at scale, SMR design activities and regulatory licensing are accelerating both domestically and abroad. The NRC has engaged in varying degrees of pre-application activities with several other SMR reactor designers and license applicants. Based on the status of SMR development, the Company anticipates SMRs could be a feasible supply-side resource as soon as the early 2030s and will continue to evaluate the feasibility of including SMRs in build plans in future filings.

Levelized Busbar Analysis

The Company's busbar model was designed to estimate the levelized energy costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include fuel, heat rate, emissions, variable and fixed operation and maintenance costs, expected service life, and overnight construction costs.

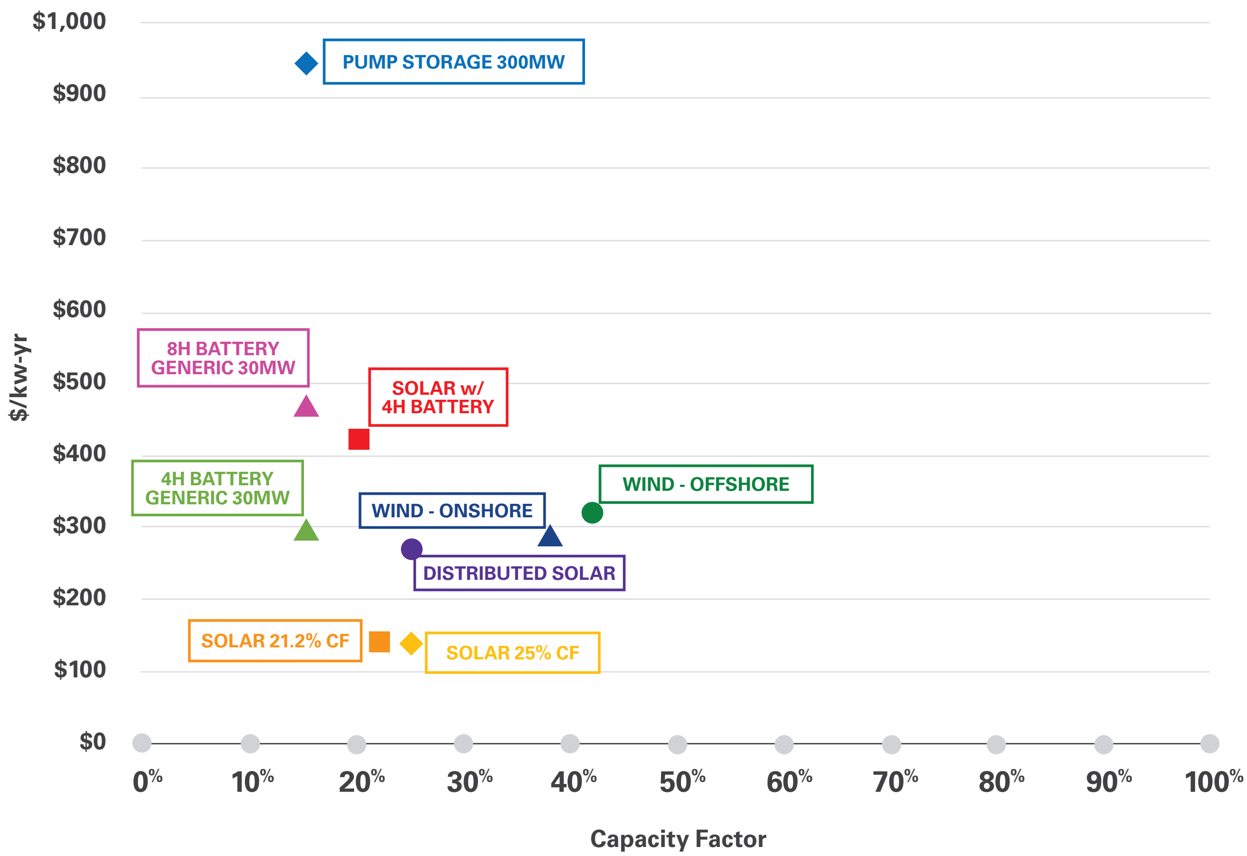
Figures 5.3.1 and 5.3.2 display high-level results of the busbar model comparing the costs of the different technologies. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources in terms of the energy and capacity value they provide to customers. For example, dispatchable resources are able to generate when power prices are the highest, while non-dispatchable resources may not have the ability to do so. Furthermore, non-dispatchable resources typically receive less capacity value for meeting the Company's reserve margin requirements and may require additional technologies in order to assure grid stability.

Figure 5.3.1: Dispatchable Levelized Busbar Costs (2027 COD)



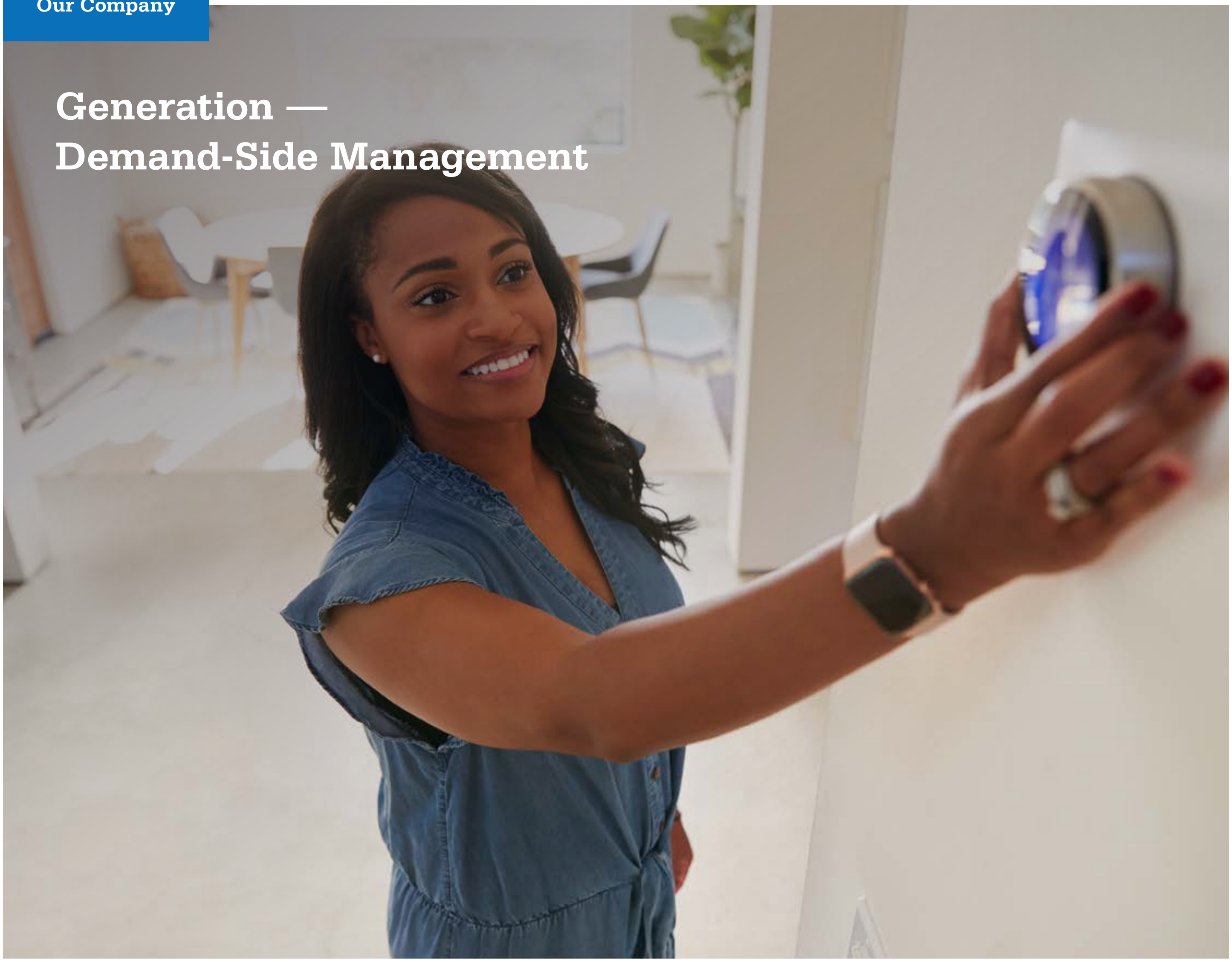
"CC" = combined cycle; "CT" = combustion turbine; "SMR" = small modular reactors (nuclear), "SCPC w/CCS" = Supercritical Pulverized Coal power plant with Carbon Capture and Storage.

Figure 5.3.2: Non-Dispatchable and Energy Storage Levelized Busbar Costs (2027 COD)



Our Company

Generation — Demand-Side Management



Customer adjusting a smart thermostat.

The Company's DSM planning process used for this 2021 Update is consistent with the process described in Chapter 6 of the 2020 Plan. Appendix 6A provides program descriptions for the currently active DSM programs, while Appendix 6F provides program descriptions for the proposed DSM programs. See ***Energy Efficiency Adjustment*** for discussion of how the Company adjusted the load forecasts used in this 2021 Update to account for energy efficiency targets.

At the end of the Planning Period (i.e., 2036), energy reductions projected for the identified DSM programs are approximately 2,643 GWh. This compares to 1,586 GWh identified in the 2020 Plan. The summer capacity reductions at the end of the Planning Period for the identified DSM programs are approximately 500 MW in this 2021 Update. This compares to 565 MW in the 2020 Plan. The majority of these changes are attributable to the proposed Phase IX DSM programs included in the 2020 Virginia DSM filing and updates associated with the 2020 evaluation, measurement, and verification report, which changed the dates and times of the coincidental capacity reductions.

Our Company

Other Information

Downtown Richmond, VA.

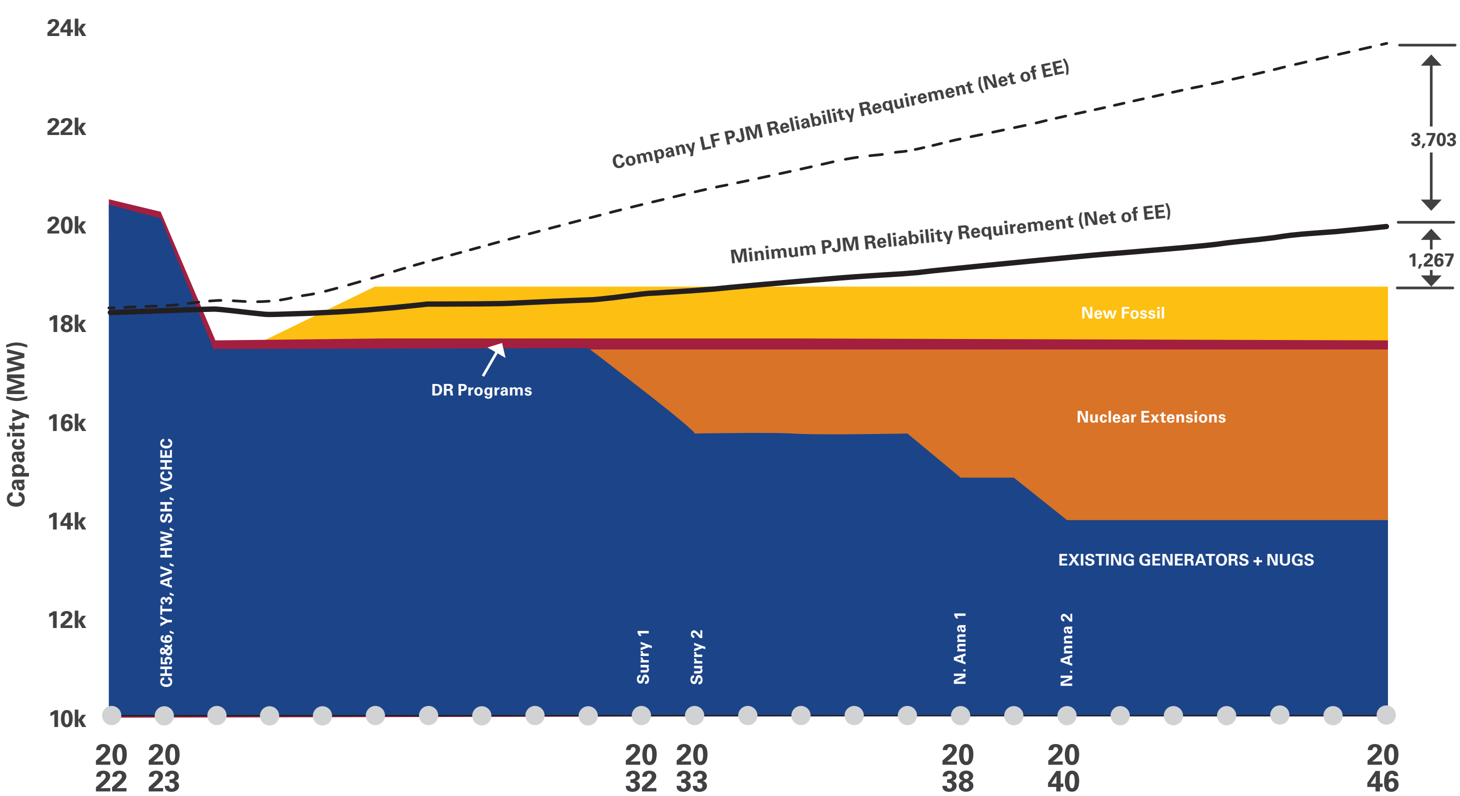
This section provides other information in response to specific SCC or NCUC requirements.

Seasonal Capacity and Energy Needs

As discussed in Chapter 5.6 of the 2020 Plan, when the Company adds increasing amounts of solar resources to the system, this will result in intra-day, intra-month, and seasonal challenges posed by the interplay of solar generation and load. These challenges could expand as neighboring states increase the amount of renewable energy generation on their systems, potentially leading to higher peak prices and a reduction in the level of imports available, similar to what happened during the Texas power crisis of February 2021. Appendix 2A shows the Company's capacity position under each Alternative Plan in the summer. Figures 7.1.1, 7.1.2, and 7.1.3 show the Company's capacity position under each Alternative Plan in the winter.

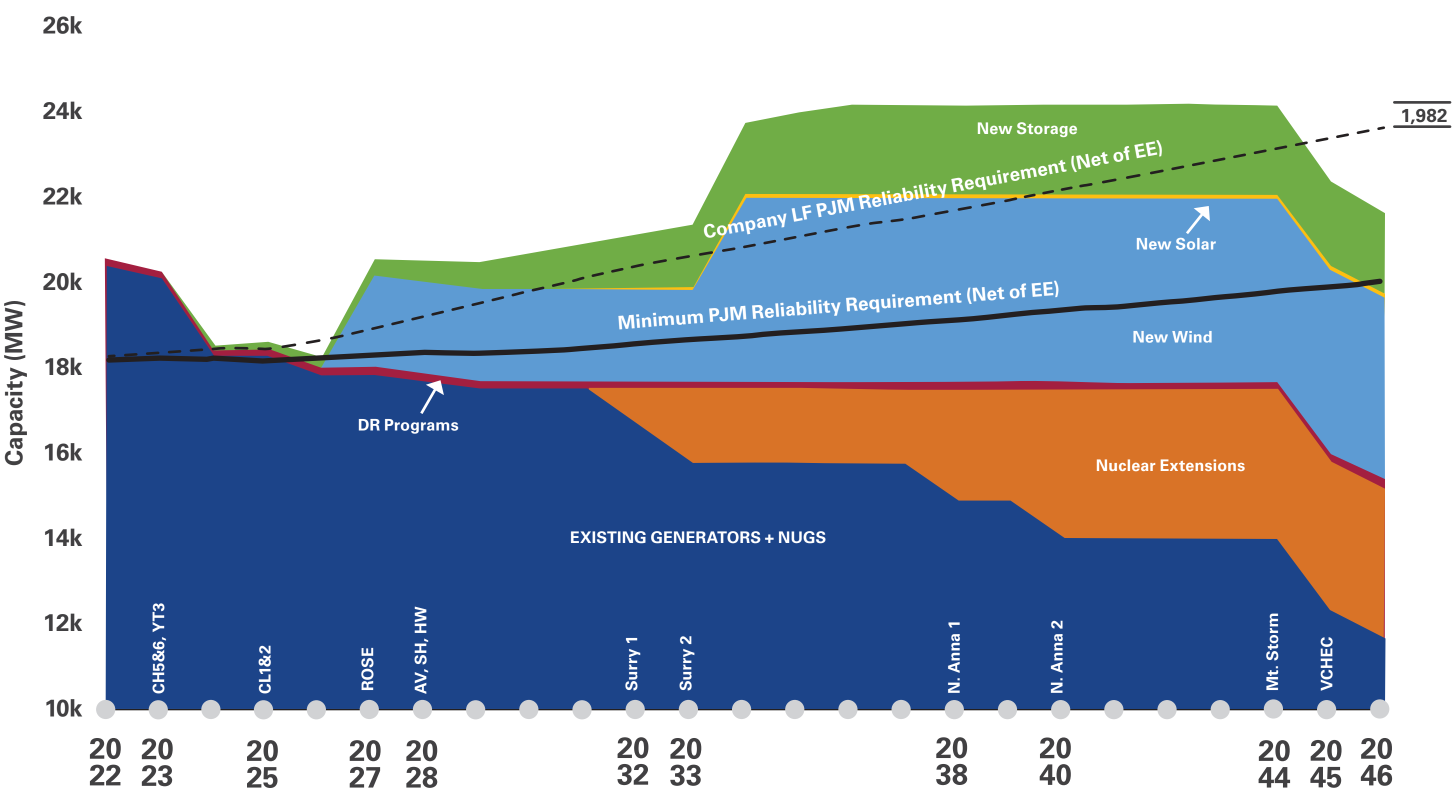
As can be seen in these figures, Alternative Plans B and C in this 2021 Update meet the winter requirements under the 2021 PJM Load Forecast in all years and under the 2021 Company Load Forecast in all but the last two years. New PJM ELCC values increased for wind and BESS; capacity values for BESS nearly doubled. The Company believes that as BESS and intermittent resources become a larger percentage of the resources in PJM, the ELCC will decrease in value, in which case the Company may need additional resources after 2035 to meet customer's winter requirements.

Figure 7.1.1: Capacity for Alternative Plan A – Winter



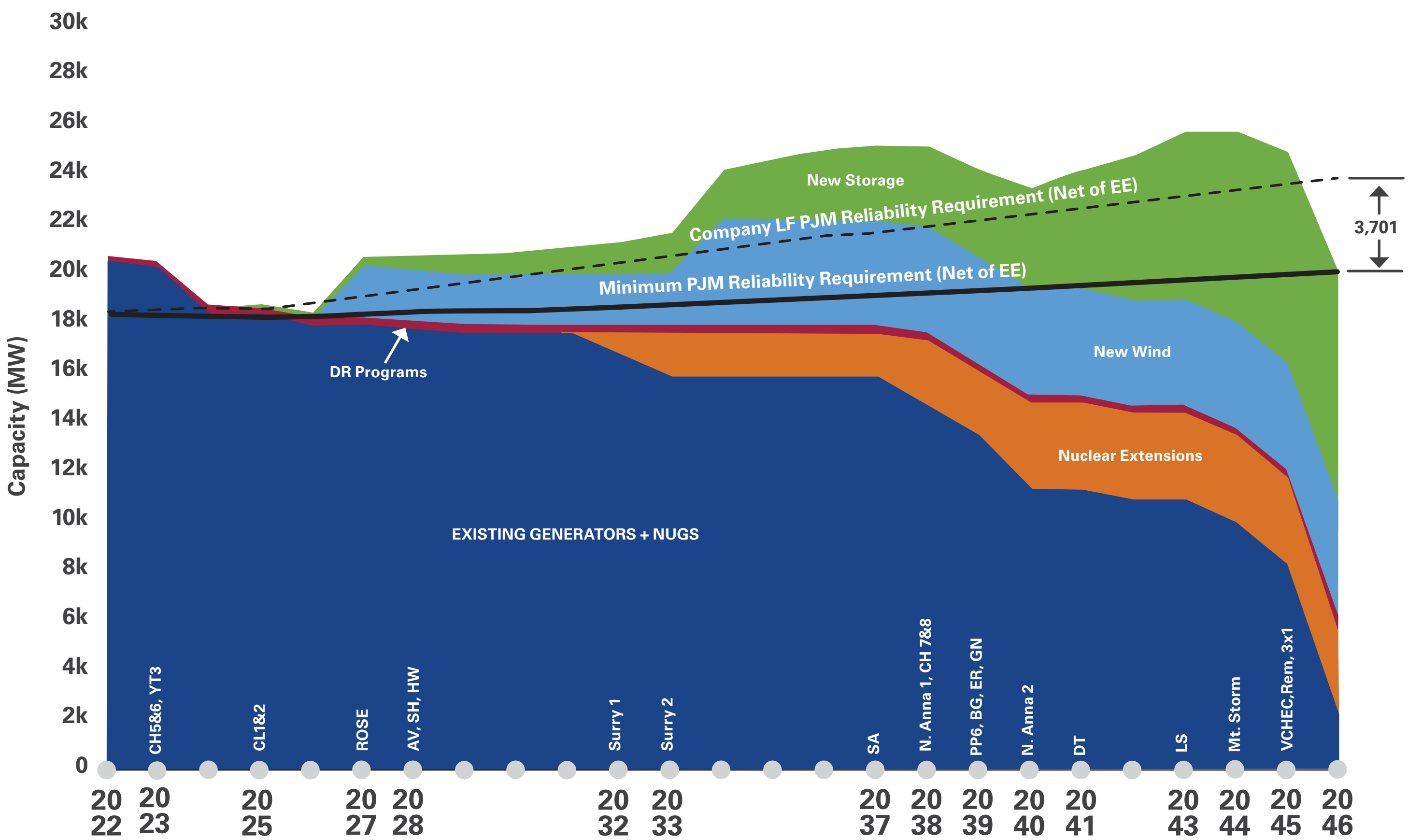
Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass); "VCHEC" = Virginia Hybrid Energy Center (coal).

Figure 7.1.2: Capacity for Alternative Plan B – Winter



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass); "VCHEC"= Virginia Hybrid Energy Center (coal); "Mt. Storm" = Mount Storm (coal).

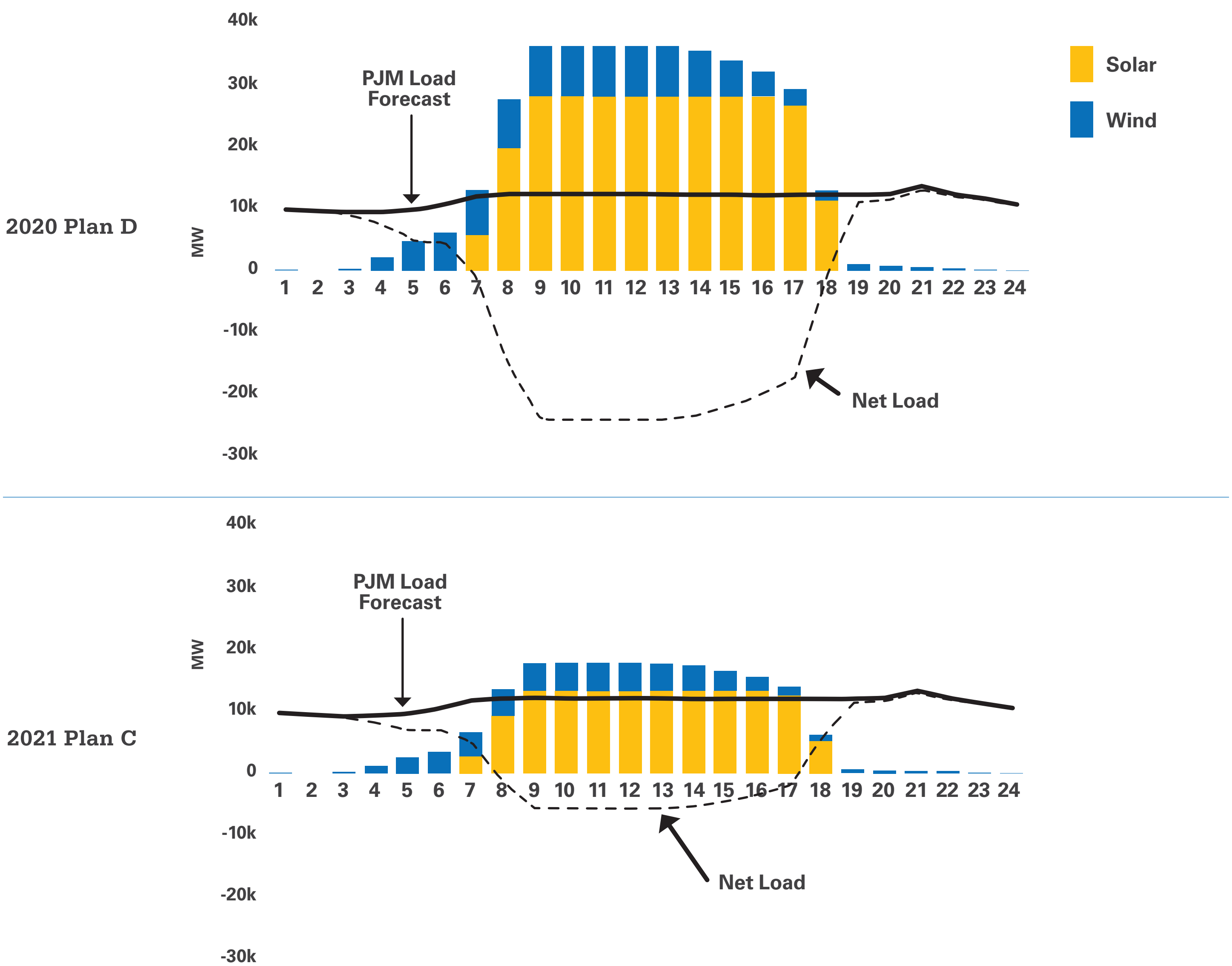
Figure 7.1.3: Capacity for Alternative Plan C – Winter



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass); "VCHEC"= Virginia Hybrid Energy Center (coal); "Mt. Storm" = Mount Storm (coal); "CH 7&8" = Chesterfield Units 7 & 8 (gas); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "ER" = Elizabeth River (gas); "GN" = Gravel Neck (gas); "DT" = Darbytown (gas); "LS" = Ladysmith (gas); "Rem" = Remington (gas); "SA" = South Anna/Gordonsville (gas); "3x1" = Warren, Brunswick, Greensville.

In addition, the future potential winter reliability issues the Company discussed in the 2020 Plan were reduced in this 2021 Update. The customer load requirements are lower and fewer new solar resources are built in the 2021 Update, making the concerns around the duck curve less impactful. Those concerns related to both the magnitude of the difference and the steepness of the net load requirements as shown in Figure 7.1.4. Even though this concern potentially occurs beyond 2035, the Company will continue to study and analyze the fleet to make sure it meets customer requirements reliably throughout the Study Period.

Figure 7.1.4: Duck Curve Comparison (2020 Plan D vs 2021 Plan C) *April 2045 (typical 24-hr day)*



The SCC directed the Company to consider market purchases during the winter from the PJM wholesale market or from merchant generators located in the DOM Zone. The Company is concerned that overreliance on the market for purchases could present issues if other states within PJM build significant amounts of solar generation and those zones expect the market to provide energy at the same time the Company is expecting that energy (e.g., extended cloudy winter periods). If that were to become reality, either energy shortages or extreme price spikes would occur. Concerning purchases from merchant generators located within the DOM Zone, those generators would likely be needed to meet the non-DOM LSE load within the DOM Zone, which is also winter peaking. The merchant generators located within the DOM Zone are likely also committed to PJM or specific customers. That said, this is not public information, making it difficult for the Company to incorporate those potential resources into its planning.

Environmental Justice

The Virginia Environmental Justice Act sets the policy of Virginia to promote environmental justice, ensuring the fair treatment and meaningful involvement of every person—regardless of race, color, national origin, income, faith, or disability—regarding the development, implementation, or enforcement of any environmental law, regulation, or policy. The Secretary of the North Carolina Department of Environmental Quality established an Environmental Justice and Equity Advisory Board to assist the agency in achieving fair and equal treatment of all communities across the state.

The clean energy transition requires substantial development of new infrastructure, which has the potential to affect surrounding communities. Dominion Energy and the Company are committed to ensuring that those communities have a meaningful voice in the planning and development processes. In cases where historically disadvantaged or marginalized communities are present, the Company's process dictates that it engage directly and intentionally to promote communication and engagement, to ensure that concerns are appropriately addressed, and that the Company works to mitigate any undue project impacts. The Company's aim is to ensure that all communities affected by its infrastructure projects have a voice in their development, and that the Company avoids disproportionately affecting or benefiting any one group as it increasingly builds infrastructure such as underground distribution lines, middle mile broadband, and other projects where community demand for the infrastructure outstrips short-term availability. The Company also wants all communities to have the chance to benefit from the economic opportunities presented by clean-energy investments.

Generally, the Company believes that environmental justice is best evaluated on a case-by-case basis, informed by the location of the project in question and project-specific characteristics. The Company notes that increasingly environmental justice will include allocating resources that communities desire, such as undergrounding distribution lines to promote greater reliability, access to EV charging infrastructure, and the Company's middle-mile broadband program. The Company has established an environmental justice review process for evaluating its specific projects and programs that implicate environmental justice consistent with relevant laws and regulations, as well as previously developed United States Environmental Protection Agency guidance, and currently accepted best practices. The Company has begun to present the results of these project-specific review processes in the relevant proceedings before the SCC, such as its applications to construct new generating facilities or new transmission lines. By contrast, attempting to evaluate generic projects in the abstract during integrated resource planning—when resources are evaluated by capacity and type in general, without any specific project facts or location—provides limited value in the Company's view.

Economic Development Rates

As of August 2021, the Company has eight customer service locations in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 231 MW. As of August 2021, the Company has no customers in North Carolina receiving service under economic development rates.

Dominion Energy

Our Company

Appendix

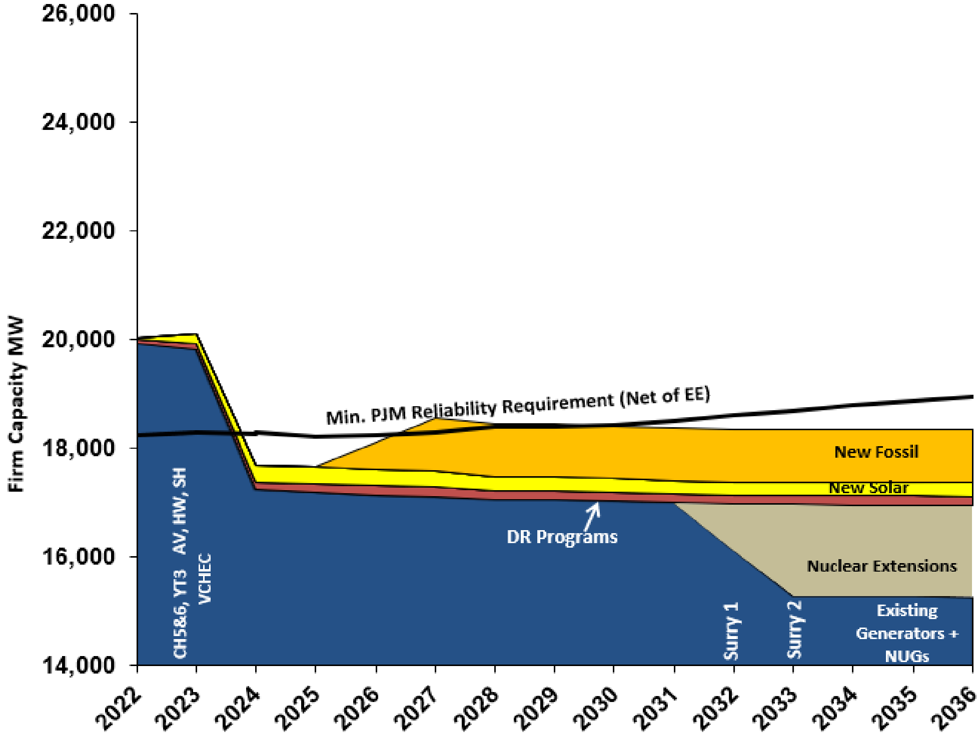
An important part of Dominion Energy's mission is to serve its customers safely and reliably.

The appendices listed below have been updated for the 2021 Update. Note that Appendices 4A through 4G are not able to be provided with the 2021 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class. Accordingly, consistent with the 2020 Plan, the Company is providing Appendices 4A through 4G using the 2021 Company Load Forecast. Unless otherwise noted, the appendix includes results for Alternative Plan B.

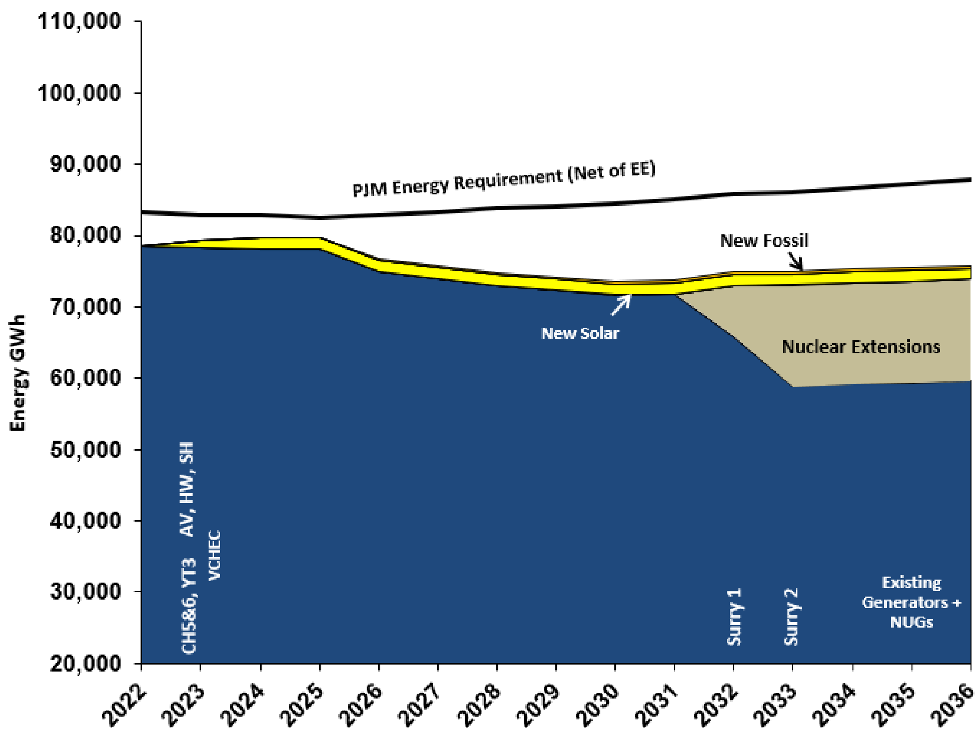
Appendix 2A	Capacity, Energy and RECs for Alternative Plans A, B, and C
Appendix 2B	Capacity Information Directed by the SCC
Appendix 3A	Generation Under Construction
Appendix 3B	Planned Generation Under Development
Appendix 3D	List of Planned Transmission Projects During the Planning Period
Appendix 4A	Total Sales by Customer Class
Appendix 4B	Virginia Sales by Customer Class
Appendix 4C	North Carolina Sales by Customer Class
Appendix 4D	Total Customer Count
Appendix 4E	Virginia Customer Count
Appendix 4F	North Carolina Customer Count
Appendix 4G	Zonal Summer and Winter Peak Demand
Appendix 4H	Projected Summer and Winter Peak Load and Energy Forecast
Appendix 4I	Required Reserve Margin
Appendix 4J	Summer and Winter Peaks
Appendix 4K	Wholesale Power Contracts
Appendix 4O	Commodity Price Forecasts
Appendix 5A	Existing Generation Units in Service
Appendix 5B	Other Generation Units
Appendix 5J	Potential Unit Retirements
Appendix 6A	Description of Active DSM Programs
Appendix 6F	Description of Proposed Phase IX DSM Programs
Appendix 7A	List of Transmission Lines under Construction

Appendix 2A: Plan A - Capacity, Energy, and RECs

Capacity

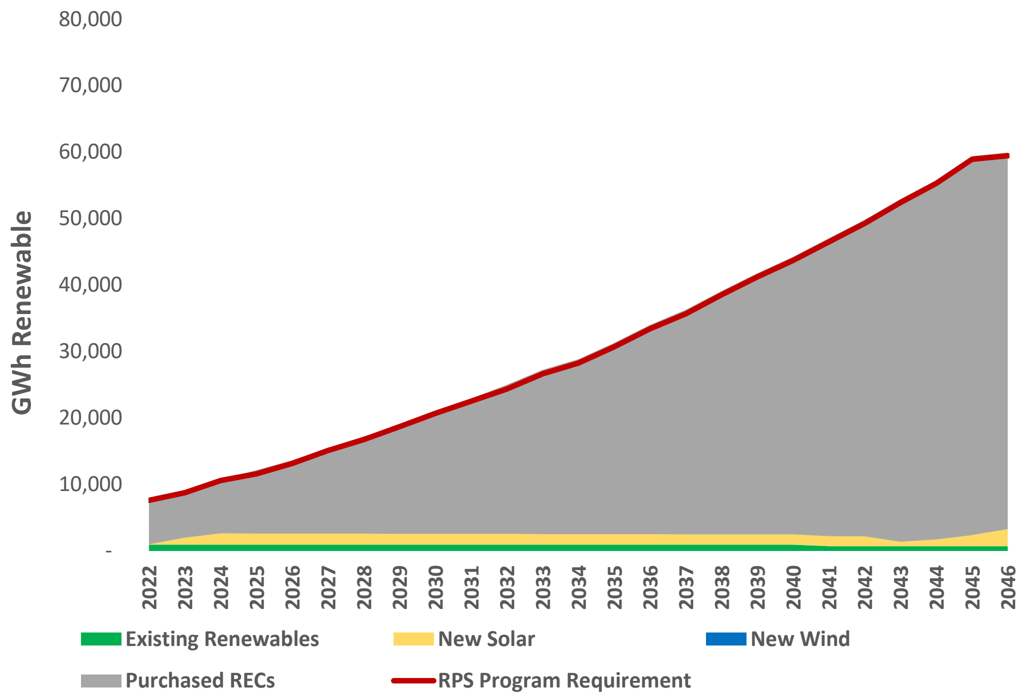


Energy



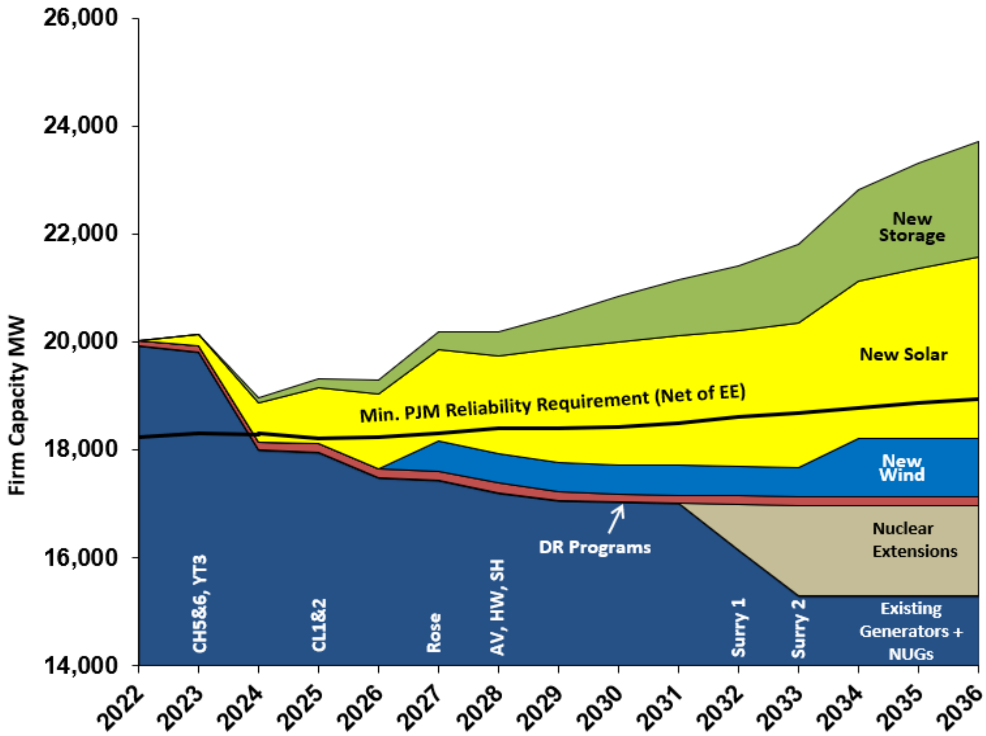
Appendix 2A: Plan A - Capacity, Energy, and RECs

RECs

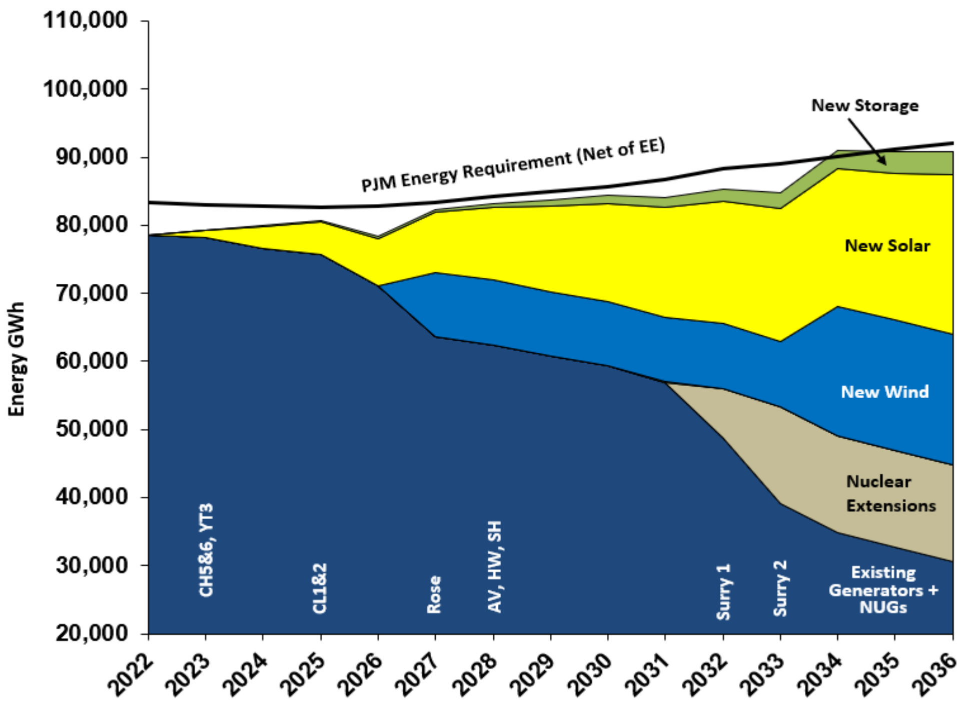


Appendix 2A: Plan B - Capacity, Energy, and RECs

Capacity

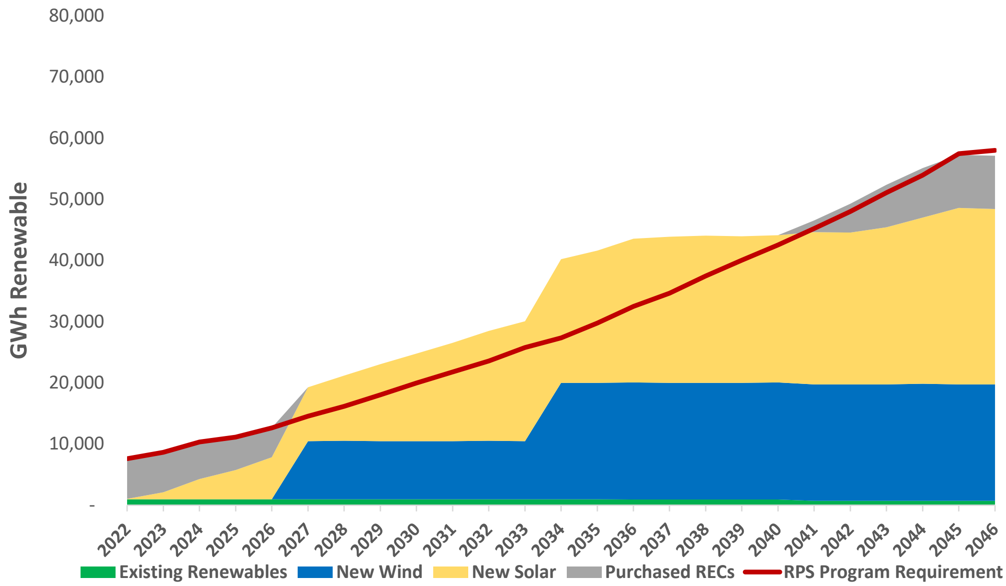


Energy



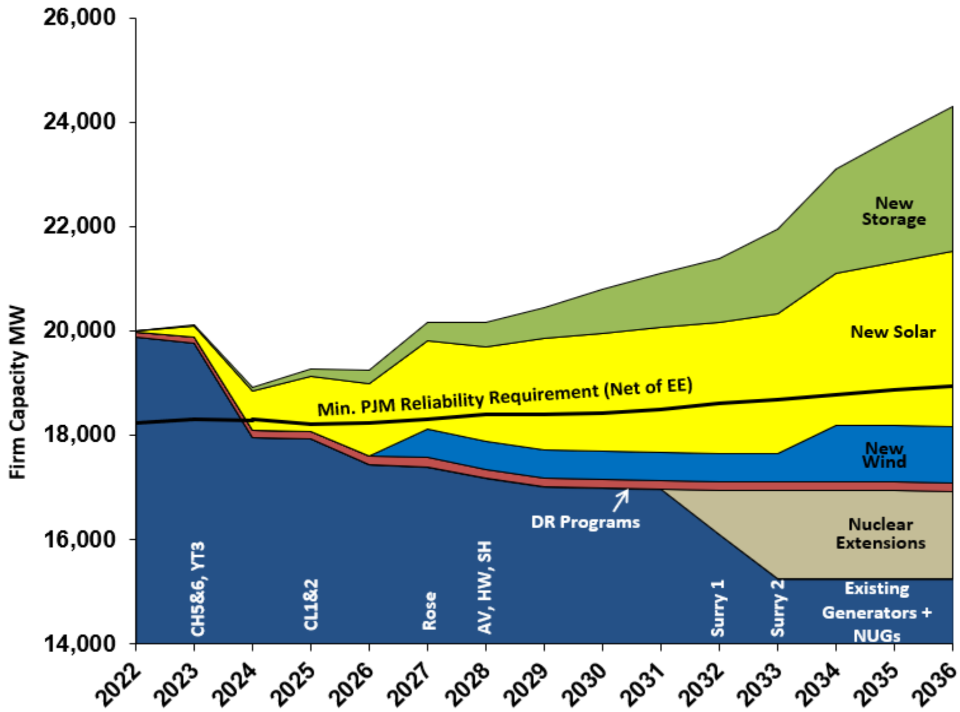
Appendix 2A: Plan B - Capacity, Energy, and RECs

RECs

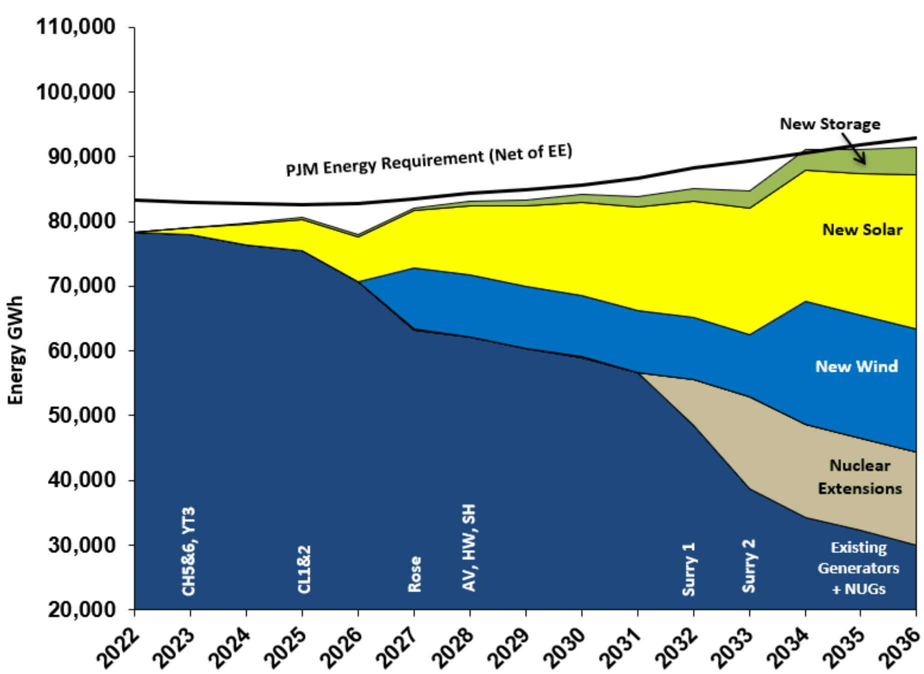


Appendix 2A: Plan C - Capacity, Energy, and RECs

Capacity

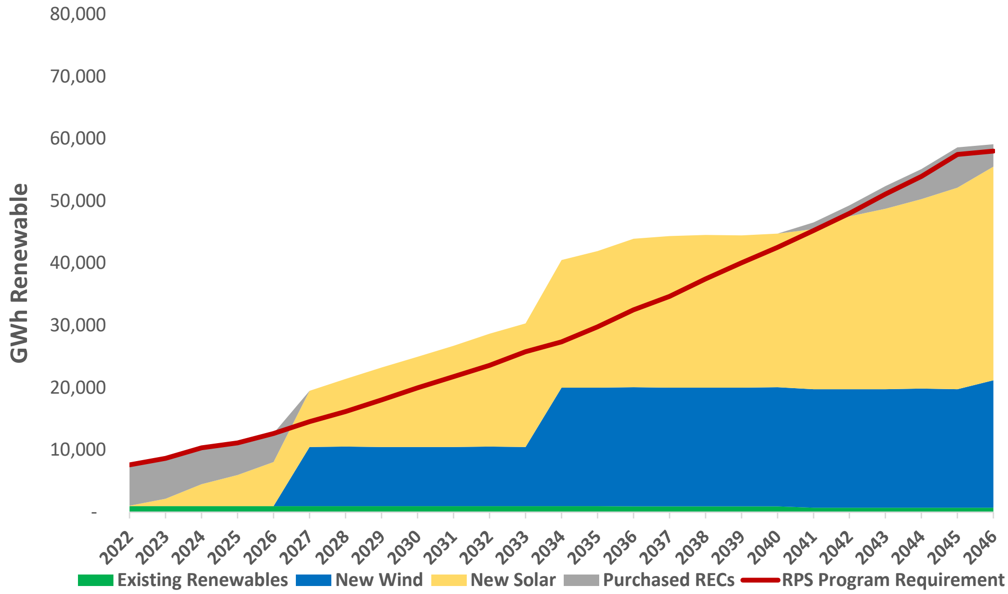


Energy



Appendix 2A: Plan C - Capacity, Energy, and RECs

RECs



Appendix 2B (i-iii): Capacity Information Directed by the SCC

	2021 PJM Load Forecast			
	Coincident Peak (CP)		Non-Coincident Peak (NCP)	
Year	DOM Zone Summer Forecast	LSE Equivalent	DOM Zone Summer Forecast	LSE Equivalent
2021	19,540	15,875	20,150	16,399
2022	19,648	15,904	20,248	16,420
2023	19,903	15,983	20,491	16,489
2024	20,109	15,995	20,694	16,498
2025	20,302	15,910	20,902	16,427
2026	20,367	15,940	20,962	16,452
2027	20,449	15,998	21,034	16,502
2028	20,532	16,081	21,109	16,578
2029	20,568	16,086	21,154	16,591
2030	20,607	16,114	21,194	16,618
2031	20,682	16,166	21,269	16,671
2032	20,776	16,258	21,365	16,765
2033	20,883	16,326	21,470	16,831
2034	20,992	16,417	21,576	16,920
2035	21,070	16,487	21,680	17,000
2036	21,129	16,559	21,775	17,100

Appendix 2B (iv-v) cont.: Capacity Information Directed by the SCC

Unit Name	Nameplate MW
Altavista	71.1
Bath County 1	477.0
Bath County 2	477.0
Bath County 3	477.0
Bath County 4	477.0
Bath County 5	477.0
Bath County 6	477.0
Bear Garden	559.0
Brunswick County	1,472.2
Chesapeake CT 1, 4, 6	51.1
Chesterfield 5	359.0
Chesterfield 6	693.9
Chesterfield 7	219.4
Chesterfield 8	227.2
Clover 1	424.0
Clover 2	424.0
Colonial Trail West	142.4
CVOW	12.0
Darbytown 1	92.1
Darbytown 2	92.1
Darbytown 3	92.1
Darbytown 4	92.1
Elizabeth River 1	129.6
Elizabeth River 2	129.6
Elizabeth River 3	129.6
Gaston 1-4	177.6
Gordonsville 1	150.2
Gordonsville 2	150.2
Gravel Neck 3	91.9
Gravel Neck 4	91.9
Gravel Neck 5	91.9
Gravel Neck 6	91.9
Gravel Neck GT 1, 2	40.1
Greensville	1,773.3
Hopewell	71.1
Ladysmith 1	178.5
Ladysmith 2	178.5
Ladysmith 3	178.5
Ladysmith 4	178.5
Ladysmith 5	178.5
Lowmoor 1	20.7

Appendix 2B (iv-v) cont.: Capacity Information Directed by the SCC

Unit Name	Nameplate MW
Lowmoor 2	20.7
Lowmoor 3	20.7
Lowmoor 4	20.7
Mt. Storm 1	570.2
Mt. Storm 2	570.2
Mt. Storm 3	522.0
Mt. Storm GT1	18.5
North Anna 1	979.7
North Anna 2	979.7
Northern Neck 1	20.7
Northern Neck 2	20.7
Northern Neck 3	20.7
Northern Neck 4	20.7
Possum Point 6	613.0
Possum Point CT 1-6	96.0
Remington 1	178.5
Remington 2	170.0
Remington 3	178.5
Remington 4	178.5
Roanoke Rapids 1-4	100.0
Rosemary	180.0
Southampton 1	71.1
Spring Grove	97.9
Surry 1	847.5
Surry 2	847.5
VCHEC	668.0
Warren	1,472.2
Yorktown 3	882.0

Appendix 2B (vi): Capacity Information Directed by the SCC

Dominion Energy Virginia
600 East Canal Street
Richmond, VA 23219
www.DominionEnergy.com

Dominion Energy

February 20, 2020

Mr. David Schweizer, P.E.
Manager, Generation
PJM Interconnection
2750 Monroe Boulevard
Audubon, PA 19403

Dear Mr. Schweizer,

Dominion Energy Virginia is requesting deactivation (retirement) of its Chesterfield 5 & 6 generating units located in Chester, Virginia. Chesterfield units 5 & 6 will be deactivated no later than May 31, 2023. Chesterfield units 5 & 6 have been committed into the RPM capacity market through May 31, 2022.

Dominion is requesting that the existing Capacity Injection Rights (CIR's) be transferred to PJM queue requests AF1-128 and AF1-129. Additionally, it is Dominion's understanding that the CIR's for previously deactivated Chesterfield units 3 & 4 have (or will) be applied to PJM queue request AF1-128. The total quantity of CIR's from deactivation will exceed those of the new requested units.

Dominion has performed financial analyses that show that current and forecasted market revenues do not support the continued operation of these units. Over the course of time the expected requirements or implementation dates for environmental or regulatory regulations may change, as well as significant changes in the energy, ancillary, and capacity markets.

Please call Jeff Currier at 804-273-4269 or Scott Gaskill at 804-273-4438 if you require any additional information.

Sincerely,

Joshua J. Bennett
Vice President Technical Services
Power Generation
Dominion Energy Virginia

Appendix 3A: Generation under Construction

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

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Annual Firm	MW Nameplate
Under Construction						
Battery Pilot	VA	Storage		2021	6	16
Grassfield Solar	VA	Intermittent	Solar	2021	7	20
Norge Solar	VA	Intermittent	Solar	2022	7	20
Sycamore Solar	VA	Intermittent	Solar	2022	14	42

(1) Commercial Operation Date

Appendix 3B: Planned Generation under Development

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

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[2]	MW Summer	MW Nameplate
Under Development[1]						
Surry Unit 1 Nuclear Extension	VA	Baseload	Nuclear	2032	838	875
Surry Unit 2 Nuclear Extension	VA	Baseload	Nuclear	2033	838	875
North Anna Unit 1 Nuclear Extension	VA	Baseload	Nuclear	2038	838	868
North Anna Unit 2 Nuclear Extension	VA	Baseload	Nuclear	2040	834	863
CE-2 Solar	VA	Intermittent	Solar	2022	1	4
CE-2 Solar	VA	Intermittent	Solar	2023	248	746
CE-2 Storage	VA	Intermittent	Solar	2022	16	20
CE-2 Storage	VA	Intermittent	Solar	2023	40	50
Commercial Offshore Wind	VA	Intermittent	Wind	2026	543	2,587

(1) Includes the additional resources under development in Plan B.

(2) Estimated commercial operation date.

Appendix 3D: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Dulles 230 kV Delivery - Add 6th Transformer	230	Aug-21	VA	0.6
Northern Neck Transformer #4 Replacement	230	Aug-21	VA	1.7
Genito 230 kV Delivery Point - DEV	230	Aug-21	VA	10.0
Winterpock 230 kV Delivery and 230 kV Ring Bus	230	Aug-21	VA	8.5
Dawson's Crossroads – Delivery Point (HEMC)	115	Aug-21	NC	0.7
Line #247 Suffolk to Swamp Rebuild	230	Sep-21	VA/NC	31.0
Waxpool 230 kV Delivery - Add 3rd Transformer	230	Nov-21	VA	0.5
Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230 kV Lines and New 230 kV Substation	230	Nov-21	VA	176.0
Varina 230 kV Delivery	230	Nov-21	VA	1
Pacific 230 kV Delivery - Add 4th Transformer	230	Nov-21	VA	0.4
Clover Substation – New 500 kV STATCOM and Rawlings Switching Station – New 500 kV STATCOM	500	Nov-21	VA	47.0
Line #49 New Road to Middleburg Rebuild	115	Dec-21	VA	12.7
Replacement of twelve 69 kV breakers at Davis Drive	69	Dec-21	VA	4.5
Line #65 Norris Bridge Rebuild	115	Dec-21	VA	103.0
Line #120 Dozier to Thompsons Corner Partial Rebuild	115	Dec-21	VA	12.6
Line #127 Buggs Island to Plywood Rebuild	115	Dec-21	VA	42.4
Line #16 Great Bridge to Hickory and Line #74 Chesapeake Energy Center to Great Bridge Rebuild	115	Dec-21	VA	27.0
New Switching Station to Retire Line #139 Everetts to Windsor DP; Hoggard Mill Substation (new station)	230/115	Dec-21	NC	11.5
Line #2173 - Loudoun to Elklick Rebuild	230	Dec-21	VA	13.5
Line #2008 Partial Rebuild and Line #156 Retirement	230/115	Dec-21	VA	14.5
Chase City 115 kV Delivery - Add 2nd Transformer	115	Dec-21	VA	0.5
Line #128 Rebuild Mt. Jackson - SVEC	115	Dec-21	VA	13.1
Plaza 230 kV Delivery - Upgrade Transformer	230	Dec-21	VA	0.5
Rollins Ford 230 kV Delivery	230	Dec-21	VA	10
Winters Branch 230 kV Delivery - Add 3rd Transformer	230	Jan-22	VA	0.25
Cut existing 115 kV Line #5 between Bremo and Cunningham substations and loop in and out of Fork Union Substation	115	Mar-22	VA	2.5
Sojourner 230 kV Delivery	230	Mar-22	VA	8
Shellhorn 230 kV Delivery – Add 3rd Transformer	230	Apr-22	VA	0.5
Line #2049 (Chesterfield – Allied) Partial Rebuild	230	Apr-22	VA	4.8
Line #2023 and Line #248 Potomac Yards Undergrounding & Glebe GIS Conversion	230	May-22	VA	120.0
Cumulus 230 kV Delivery - Add 3rd Transformer	230	Jun-22	VA	0.4
Paragon Park 230 kV Delivery - DEV	230	Jun-22	VA	2.5
BECO - Add 5th Transformer	230	Jun-22	VA	0.5
Cloverhill 230 kV Delivery - Add 3rd Transformer	230	Jun-22	VA	0.25
Line #274 Pleasant View to Beaumeade Rebuild	230	Jun-22	VA	10.0
Line #2001 Possum Point to Occoquan Reconductor and Uprate	230	Jun-22	VA	4.7
Line #43 Staunton - Harrisonburg Rebuild	115	Jun-22	VA	39.6
Lucky Hill Substation	230	Jul-22	VA	7.5
Lockridge 230 kV Delivery - DEV	230	Jul-22	VA	14.5
Poland Road 230 kV Delivery - Add 4th Transformer	230	Sep-22	VA	0.4
Nivo - Add 4th Transformer and Four Breaker Ring	230	Sep-22	VA	7
Lines #53 and #72 (Chesterfield to Brown Boveri Tap) Partial Rebuild	115	Sep-22	VA	9.75
Davis Drive - Add 3rd and 4th Transformer	230	Oct-22	VA	1
Youngs Branch 230 kV Delivery	230	Oct-22	VA	10
Nokesville - Add 2nd Transformer	230	Nov-22	VA	0.75
Sinai 115 kV Delivery - Add 2nd TX - DEV	115	Nov-22	VA	0.5
Nimbus 230 kV Delivery - DEV	230	Nov-22	VA	20.0
Wakeman 230 kV Delivery and new 230 kV line extension from Winters Banch to	230	Dec-22	VA	10.6
Hamilton - Add 2nd Transformer	230	Dec-22	VA	0.75
Garysville 230 kV Delivery - PGEC	230	Dec-22	VA	3
Shellhorn - Add 4th Transformer	230	Dec-22	VA	0.5
Line #239 and Line #2141 Partial Rebuild	230	Dec-22	VA	5

Appendix 3D: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Line #2175 Idylwood to Tysons – New 230 kV Line and Rebuild Tysons with GIS	230	Dec-22	VA	181.8
Line #552 Bristers to Chancellor Rebuild	500	Dec-22	VA	62.2
Line #205 and #2003 Chesterfield to Tyler Partial Rebuild	230	Dec-22	VA	11.1
Line #29 Fredericksburg to Possum Point Partial Rebuild	115	Dec-22	VA	19.2
Line #295 and Partial Line #265 Rebuild	230	Dec-22	VA	15.5
Line #17 – Chesterfield to Northeast Rebuild	115	Dec-22	VA	18.2
Lines #73 – Elmont to Four Rivers Rebuild	115	Dec-22	VA	11.7
Line #100 – Locks to Harrowgate Partial Rebuild	115	Dec-22	VA	6.9
Edinburg Transformer #3 Replacement	138/115	Dec-22	VA	3
Line #239 and Line #2141 Partial Rebuild	230	Dec-22	NC	5
Harrisonburg Transformer #4 Replacement	230/69	Dec-22	VA	3.2
Cumulus 230 kV Delivery - Add 4th Transformer	230	Dec-22	VA	0.5
Line #45 (Kerr Dam to Duke Interconnection) Rebuild	115	Dec-22	VA	9.3
Line #96 (Everetts to Parmele) Rebuild	115	Dec-22	NC	27
Farmwell 230 kV Delivery - Add 3rd Transformer	230	Jan-23	VA	0.5
Waxpool 230 kV Delivery - Add 4th Transformer	230	Mar-23	VA	0.4
Winters Branch 230 kV Delivery - Add 4th Transformer	230	Mar-23	VA	0.25
Judes Ferry 230 kV DP	230	May-23	VA	1.1
Fines Corner 230 kV DP	230	May-23	VA	1.0
Brickyard 230 kV Delivery	230	May-23	VA	2.0
King and Queen 230 kV Delivery	230	Jun-23	VA	1.86
Chickahominy 2nd 500-230 kV 2nd Transformer	500/230	Jun-23	VA	22
New 2nd 230 kV circuit (Lanexa to Northern Neck)	230	Jun-23	VA	14
Northern Neck - Expand the 230 kV 4-breaker ring bus to a 6-breaker ring bus	230	Jun-23	VA	5
Lanexa - Expand 230 kV 6-breaker ring bus to a breaker-and-a-half arrangement	230	Jun-23	VA	4
Line #172 (Liberty to Lomar) and Line #197 (Cannon Branch to Lomar) - Conversion to 230 kV	230	Jun-23	VA	10
Liberty, Wellington, Godwin, Pioneer, Sandlot and Cannon Branch - Perform substation work for the 115 kV to 230 kV Line conversion	230	Jun-23	VA	21
Line #2011 (Cannon Branch to Clifton) - Extension to Winters Branch via Brickyard	230	Jun-23	VA	10
Substation work for the 230 kV Line #2011 extension at Cannon Branch, Brickyard and Winters Branch	230	Jun-23	VA	4
Line #227 Partial Rebuild	230	Jun-23	VA	15.8
Possum Point Breakers Replacement	230	Jun-23	VA	19.0
Global Plaza 230 kV Delivery - DEV	230	Jun-23	VA	40.0
New Station to Retire Line #5 Fork Union to Cunningham DP Segment	115	Jun-23	VA	16.3
Mercury 115 kV Delivery - Add 2nd Transformer	115	Sep-23	VA	0.5
Lincoln Park 230 kV Delivery	230	Sep-23	VA	10
Hourglass 230 kV Delivery – NOVEC	230	Sep-23	VA	11
Prince Edward 230 kV DP	230	Nov-23	VA	1.2
Fredericksburg Transformer #7 Replacement	230/115	Nov-23	VA	4
Line #550 Mount Storm to Valley Rebuild	500	Dec-23	WV/VA	288.2
Line #581 Chancellor - Ladysmith 500 kV Rebuild	500	Dec-23	VA	44.4
Line #34 Skiffes Creek to Yorktown and Line #61 Whealton to Yorktown Partial Rebuild and Fort Eustis Tap Rebuild	115	Dec-23	VA	24.2
Line #224 Lanexa to Northern Neck Rebuild	230	Dec-23	VA	86.0
Lines #265, 200, and 2051 Partial Rebuild	230	Dec-23	VA	11.5
Line #141 & Line #28 Rebuild	115	Dec-23	VA	20.0
Peninsula Transformer #4 Replacement and 230 kV Ring Bus	230	Dec-23	VA	16.1
DTC 230 kV Delivery - DEV	230	Dec-23	VA	25.0
Harrisonburg Transformer #6 Replacement	230/69	Dec-23	VA	3.2
Line #238 (Carson to Clubhouse) and Line #249 (Carson to Locks) Partial Rebuild	230	Dec-23	VA	3.5
Line #2002 (Carson to Poe) Partial Rebuild	230	Dec-23	VA	4.25
Line #1024 (Chestnut to South Justice Branch) Rebuild	115	Dec-23	VA	5.1
Line #87 (Churchland to Hodges Ferry) Partial Rebuild	115	Dec-23	VA	8
Line #26 (Balcony Falls to Buena Vista) Partial Rebuild	115	Dec-23	VA	15.3
Line #83 (Craigsville to Line #83/293 Junction) Partial Rebuild	115	Dec-23	VA	23
Mt. Storm - GIS	500	May-24	WV	69.0

Appendix 3D: List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Cloud 230 kV Delivery- MEC and two single circuit 230 kV lines extension to Cloud from Line #235 (Clover - Farmville)	230	Jun-24	VA	45
Easters 230 kV Delivery - MEC	230	Jun-24	VA	20
Line #53 (Chesterfield - Kevlar) Install Reymet Tap	115	Jun-24	VA	3
New 230 kV Switching Station (Stevensburg - Batna) with a 224 MVA, 230/115 kV transformer. Line #2199 (Gordonsville to Remington), Line #70 (Remington to Mt. Run) and Line #2 (Mt. Run to Oak Green) will be connected to the new station.	230/115	Jun-24	VA	22
Takeoff 230 kV Delivery - Add Two Transformers	230	Jun-24	VA	1
Park Center 230 kV Delivery	230	Aug-24	VA	10
Altair 230 kV Delivery - NOVEC	230	Sep-24	VA	15
Racefield 230 kV Delivery	230	Nov-24	VA	12
Interconnection 230 kV Delivery	230	Dec-24	VA	16
Line#1001 (Battleboro to Chestnut) Rebuild	115	Dec-24	VA	14
Line #574 Elmont to Ladysmith Rebuild	500	Dec-24	VA	65.5
Line #2113 Waller to Lightfoot Partial Rebuild	230	Dec-24	VA	4.0
Line #2154 and #19 Waller to Skiffes Creek Rebuild	230	Dec-24	VA	10.0
Lines #2063 and Partial #2164 Rebuild	230	Dec-24	VA	22.0
Line #81 and Partial Line #2056 Rebuild	115/230	Dec-24	NC	25.0
Line #254 Clubhouse-Lakeview Rebuild	230	Dec-24	VA	27.0
Line #2181 and Line #2058 Hathaway to Rocky Mount (DEP) Rebuild	230	Dec-24	NC	13.0
Line #569 Loudoun - Morrisville Rebuild	500	Dec-24	VA	4.5
Line #14 (Fudge Hollow to AEP Interconetion) Partial Rebuild	138	Dec-24	VA	30
Aviator 230 kV Delivery	230	Feb-25	VA	22
Line #514 (Doubs to Goose Creek) Partial Rebuild and Uprate Line terminal	500	Jun-25	VA	7.6
Line #117 - Install 115 kV breaker at Stuarts Draft station to sectionalize 115 kV line	115	Jun-25	VA	5
Line #2172 (Brambleton to Evergreen Mills - Circuit 1) Reconductor and Uprate	230	Jun-25	VA	2.32
Line #2210 (Brambleton to Evergreen Mills - Circuit 2) Reconductor and Uprate	230	Jun-25	VA	2.26
Line #2213 from Cabin Run to Yardley Ridge Reconductor and Uprate	230	Jun-25	VA	1.75
New single circuit 230 kV line extension (Farmwell to Nimbus)	230	Jun-25	VA	5.7
Midlothian Area 300 MW Load Drop Relief Area Improvements	230	Jun-25	VA	6.22
Columbia Tap - CVEC	115	Oct-25	VA	7.0
Harrisonburg 2nd 115 kV 33.67MVar cap bank and a 115 kV breaker	115	Dec-25	VA	1.25
New switching station (Walnut Creek) at the junction of 115 kV line #39 and 115 kV line #91 with a 115 kV capacitor bank	115	Dec-25	VA	3
Line #293 and Partial Line #83 Rebuild	230	Dec-25	VA	44.8
Line #2019 (Thalia to Greenwich) Partial Rebuild	230	Dec-25	VA	3
Line #2010 Underground Relocation	230	Dec-25	VA	40
Spring Hill 230 kV Delivery	230	Dec-25	VA	35.0
Line #209 and Line #58 Partial Rebuild	230/115	Dec-25	VA	19.5
Re-conductor Line #2114 (Remington CT – Elk Run – Rollins Ford)	230	Dec-25	VA	35
Re-conductor Line #2222 (Rollins Ford – Gainesville)	230	Dec-25	VA	2
Re-conductor Line #2008 (Cub Run – Walney – Takeoff)	230	Dec-25	VA	6
New 230 kV double-circuit line extension to Global Plaza from Line #2015 (Dulles to Reston)	230	Dec-25	VA	44
New 230 kV substation (Takeoff) and a new 230 kV double-circuit line extension from Aviator to Takeoff. Reconductor three 230 kV lines.	230	Dec-25	VA	76.7
Line #2007 (Lynnhaven to Thalia) Rebuild	230	Dec-25	VA	7
Line #2011(Clifton to Cannon Branch) Re-conductor	230	Dec-25	VA	17
Line #2152 (Beaumeade to Nimbus) Re-conductor	230	Dec-25	VA	6
Line # (Nimbus to Buttermilk) Re-conductor	230	Dec-25	VA	5
Line #2143 and #2150 (Beaumeade to Paragon Park) Re-conductor	230	Dec-25	VA	4
Line #2209 (Evergreen Mills to Yardley Ridge) Re-conductor	230	Dec-25	VA	5
Line #2095 (Cabin Run to Shellhorn) Re-conductor	230	Dec-25	VA	8
Idylwood - Convert Straight Bus to Breaker-and-a-Half	230	Dec-26	VA	159.0
Line #272 (Dooms to Grottoes) Rebuild	230	Dec-26	VA	30.8

Appendix 4A: Total (DOM LSE) Sales (GWh) by Customer Class

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2009	29,904	28,455	8,644	10,448	276	1,990	79,716
2010	32,547	29,233	8,512	10,670	281	1,932	83,175
2011	30,779	28,957	7,960	10,555	273	1,921	80,445
2012	29,174	28,927	7,849	10,496	277	2,011	78,735
2013	30,184	29,372	8,097	10,261	276	1,984	80,174
2014	31,290	29,964	8,812	10,402	261	1,956	82,685
2015	30,923	30,282	8,765	10,159	275	1,981	82,385
2016	28,213	31,366	8,715	10,161	253	1,856	80,564
2017	29,737	32,292	8,638	10,555	258	1,609	83,088
2018	32,139	33,591	8,324	10,761	260	1,607	86,681
2019	31,439	35,296	7,302	10,645	263	1,580	86,524
2020	32,670	32,911	6,503	11,073	261	1,472	84,889
2021	31,046	34,867	6,685	10,658	247	1,546	85,050
2022	31,621	37,103	6,849	10,300	243	1,523	87,639
2023	31,765	38,071	6,902	10,318	242	1,531	88,829
2024	31,947	38,974	6,878	10,298	241	1,527	89,865
2025	31,986	39,741	6,813	10,264	240	1,523	90,567
2026	32,414	41,037	6,790	10,229	239	1,513	92,223
2027	33,024	42,376	6,780	10,197	235	1,498	94,110
2028	33,686	43,744	6,755	10,164	234	1,473	96,057
2029	34,336	44,992	6,729	10,164	233	1,448	97,903
2030	35,032	46,119	6,677	10,164	232	1,420	99,643
2031	35,817	47,168	6,599	10,164	231	1,389	101,367
2032	36,661	48,155	6,517	10,164	230	1,349	103,077
2033	37,366	48,902	6,441	10,164	230	1,314	104,416
2034	38,151	49,557	6,363	10,164	229	1,275	105,739
2035	38,946	50,055	6,282	10,164	228	1,234	106,909
2036	39,821	50,430	6,203	10,163	227	1,185	108,030

Note: Historic (2009 - 2020); Projected (2021 - 2036)
Appendix 4A has been provided with the 2021 Company Load Forecast instead of the 2021 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4B: Virginia Sales (GWh) by Customer Class

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2009	28,325	27,646	7,147	10,312	268	1,901	75,599
2010	30,831	28,408	6,872	10,529	273	1,883	78,797
2011	29,153	28,163	6,342	10,423	265	1,870	76,216
2012	27,672	28,063	6,235	10,370	269	1,958	74,568
2013	28,618	28,487	6,393	10,134	267	1,934	75,833
2014	29,645	29,130	6,954	10,272	253	1,906	78,160
2015	29,293	29,432	7,006	10,029	266	1,930	77,956
2016	26,652	30,537	6,947	10,033	245	1,803	76,217
2017	28,194	31,471	6,893	10,429	250	1,556	78,794
2018	30,437	32,752	6,598	10,633	252	1,555	82,228
2019	29,829	34,472	5,591	10,517	254	1,530	82,194
2020	30,969	32,159	4,872	10,924	253	1,425	80,602
2021	29,415	34,108	4,933	10,510	240	1,496	80,702
2022	29,919	36,351	5,217	10,151	235	1,474	83,348
2023	30,062	37,319	5,269	10,169	234	1,483	84,535
2024	30,243	38,222	5,244	10,148	233	1,479	85,569
2025	30,281	38,988	5,179	10,115	232	1,474	86,269
2026	30,708	40,284	5,155	10,080	232	1,465	87,922
2027	31,317	41,622	5,144	10,047	227	1,450	89,807
2028	31,978	42,990	5,118	10,014	226	1,426	91,752
2029	32,626	44,237	5,091	10,014	225	1,402	93,596
2030	33,321	45,363	5,037	10,014	224	1,375	95,335
2031	34,105	46,412	4,959	10,014	224	1,344	97,057
2032	34,948	47,399	4,875	10,014	223	1,306	98,766
2033	35,655	48,145	4,798	10,014	222	1,272	100,105
2034	36,436	48,800	4,720	10,013	221	1,234	101,425
2035	37,230	49,298	4,638	10,013	220	1,195	102,594
2036	38,104	49,672	4,558	10,013	219	1,148	103,714

Note: Historic (2009 - 2020); Projected (2021 - 2036)
Appendix 4B has been provided with the 2021 Company Load Forecast instead of the 2021 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4C: North Carolina Sales (GWh) by Customer Class

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2009	1,579	809	1,497	136	8	88	4,117
2010	1,716	825	1,640	141	8	49	4,379
2011	1,626	795	1,618	132	8	51	4,230
2012	1,502	864	1,614	126	8	53	4,167
2013	1,567	885	1,704	127	8	50	4,341
2014	1,645	834	1,858	130	8	50	4,525
2015	1,630	850	1,759	130	8	51	4,428
2016	1,562	829	1,768	128	8	53	4,347
2017	1,542	821	1,744	126	8	53	4,294
2018	1,701	839	1,725	128	8	52	4,453
2019	1,610	824	1,710	127	9	50	4,331
2020	1,701	751	1,630	149	8	47	4,287
2021	1,631	760	1,752	148	7	50	4,348
2022	1,702	752	1,631	149	8	49	4,291
2023	1,703	752	1,632	149	8	49	4,294
2024	1,704	753	1,633	149	8	49	4,296
2025	1,705	753	1,634	149	8	49	4,299
2026	1,706	754	1,635	149	8	48	4,301
2027	1,708	754	1,636	150	8	48	4,303
2028	1,709	755	1,637	150	8	47	4,305
2029	1,710	755	1,638	150	8	46	4,307
2030	1,711	755	1,639	150	8	45	4,308
2031	1,712	756	1,640	150	8	44	4,310
2032	1,713	756	1,641	150	8	43	4,311
2033	1,712	757	1,642	150	8	42	4,311
2034	1,715	757	1,643	150	8	41	4,314
2035	1,716	758	1,644	150	8	39	4,315
2036	1,717	758	1,645	150	8	38	4,316

Note: Historic (2009 - 2020); Projected (2021 - 2036)
Appendix 4C has been provided with the 2021 Company Load Forecast instead of the 2021 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4D: Total (DOM LSE) Customer Count

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2009	2,139,604	232,148	581	29,073	2,687	5	2,404,099
2010	2,157,581	232,988	561	29,041	2,798	5	2,422,974
2011	2,171,795	233,760	535	29,104	3,031	5	2,438,229
2012	2,187,670	234,947	514	29,114	3,246	4	2,455,496
2013	2,206,657	236,596	526	28,847	3,508	3	2,476,138
2014	2,229,639	237,757	631	28,818	3,653	3	2,500,500
2015	2,252,438	239,623	662	28,923	3,814	3	2,525,463
2016	2,275,551	240,804	654	29,069	3,941	3	2,550,022
2017	2,298,894	242,091	648	28,897	4,149	3	2,574,683
2018	2,323,662	243,701	644	28,716	4,398	3	2,601,124
2019	2,362,949	246,043	634	28,452	4,792	3	2,642,873
2020	2,397,544	246,865	626	29,883	4,889	3	2,679,810
2021	2,412,685	247,962	600	29,866	4,960	3	2,696,076
2022	2,444,073	250,330	590	29,844	5,104	3	2,729,944
2023	2,475,142	252,785	584	29,817	5,248	3	2,763,579
2024	2,505,836	255,216	578	29,791	5,392	3	2,796,815
2025	2,536,933	257,669	572	29,766	5,536	3	2,830,479
2026	2,568,027	260,126	566	29,748	5,680	3	2,864,150
2027	2,597,789	262,503	560	29,732	5,824	3	2,896,411
2028	2,625,488	264,753	554	29,717	5,968	3	2,926,483
2029	2,651,346	266,888	548	29,699	6,112	3	2,954,596
2030	2,676,084	268,953	542	29,682	6,256	3	2,981,520
2031	2,699,958	270,964	536	29,666	6,400	3	3,007,527
2032	2,723,087	272,928	530	29,650	6,544	3	3,032,742
2033	2,745,530	274,851	524	29,636	6,688	3	3,057,232
2034	2,767,457	276,741	518	29,622	6,832	3	3,081,173
2035	2,789,018	278,608	512	29,609	6,976	3	3,104,726
2036	2,810,278	280,456	506	29,597	7,120	3	3,127,960

Note: Historic (2009 - 2020); Projected (2021 - 2036)
Appendix 4D has been provided with the 2021 Company Load Forecast instead of the 2021 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4E: Virginia Customer Count

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2009	2,038,843	216,663	522	27,206	2,290	3	2,285,526
2010	2,056,576	217,531	504	27,185	2,404	3	2,304,203
2011	2,070,786	218,341	482	27,252	2,639	3	2,319,503
2012	2,086,647	219,447	464	27,265	2,856	2	2,336,680
2013	2,105,500	221,039	477	26,996	3,118	2	2,357,131
2014	2,128,313	222,143	579	26,966	3,267	2	2,381,269
2015	2,150,818	223,946	611	27,070	3,430	2	2,405,877
2016	2,173,472	225,029	603	27,223	3,560	2	2,429,889
2017	2,196,466	226,270	596	27,041	3,768	2	2,454,143
2018	2,220,797	227,757	594	26,872	4,017	2	2,480,039
2019	2,259,491	229,988	584	26,614	4,417	2	2,521,096
2020	2,292,457	230,782	576	27,901	4,516	2	2,556,234
2021	2,308,256	232,226	551	27,874	4,581	2	2,573,489
2022	2,339,208	234,558	541	27,852	4,725	2	2,606,886
2023	2,369,851	236,978	535	27,826	4,870	2	2,640,062
2024	2,400,118	239,374	529	27,801	5,014	2	2,672,838
2025	2,430,778	241,791	523	27,777	5,158	2	2,706,030
2026	2,461,447	244,213	517	27,759	5,303	2	2,739,242
2027	2,490,808	246,557	511	27,744	5,447	2	2,771,069
2028	2,518,139	248,776	505	27,730	5,592	2	2,800,743
2029	2,543,647	250,880	499	27,713	5,736	2	2,828,478
2030	2,568,049	252,916	493	27,696	5,881	2	2,855,037
2031	2,591,597	254,898	487	27,681	6,025	2	2,880,690
2032	2,614,409	256,835	481	27,666	6,170	2	2,905,562
2033	2,636,546	258,730	475	27,652	6,314	2	2,929,718
2034	2,658,171	260,593	469	27,638	6,459	2	2,953,331
2035	2,700,695	264,281	457	27,613	6,747	2	2,999,796
2036	2,700,401	264,255	457	27,614	6,747	2	2,999,477

Note: Historic (2009 - 2020); Projected (2021 - 2036)
Appendix 4E has been provided with the 2021 Company Load Forecast instead of the 2021 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4F: North Carolina Customer Count

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2009	100,761	15,485	59	1,867	398	2	118,573
2010	101,005	15,457	56	1,857	395	2	118,772
2011	101,009	15,418	53	1,852	392	2	118,726
2012	101,024	15,501	50	1,849	390	2	118,816
2013	101,158	15,557	50	1,851	390	1	119,007
2014	101,326	15,614	52	1,853	386	1	119,231
2015	101,620	15,677	52	1,853	384	1	119,586
2016	102,079	15,775	51	1,846	381	1	120,133
2017	102,429	15,821	52	1,857	381	1	120,541
2018	102,865	15,944	50	1,844	381	1	121,085
2019	103,458	16,055	50	1,838	375	1	121,777
2020	105,087	16,083	50	1,982	373	1	123,576
2021	104,429	15,736	49	1,993	379	1	122,587
2022	104,865	15,772	49	1,992	379	1	123,057
2023	105,291	15,807	49	1,991	378	1	123,517
2024	105,717	15,842	49	1,990	378	1	123,977
2025	106,155	15,878	49	1,989	378	1	124,449
2026	106,580	15,913	49	1,988	377	1	124,909
2027	106,981	15,946	49	1,988	377	1	125,341
2028	107,349	15,977	49	1,987	376	1	125,739
2029	107,698	16,008	49	1,986	376	1	126,118
2030	108,035	16,037	49	1,986	375	1	126,483
2031	108,361	16,066	49	1,985	375	1	126,837
2032	108,677	16,094	49	1,985	374	1	127,180
2033	108,984	16,121	49	1,984	374	1	127,513
2034	109,286	16,148	49	1,984	373	1	127,841
2035	109,583	16,175	49	1,983	373	1	128,164
2036	109,876	16,201	49	1,983	373	1	128,483

Note: Historic (2009 - 2021); Projected (2022 - 2036)
Appendix 4F has been provided with the 2021 Company Load Forecast instead of the 2021 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4G: Zonal Summer and Winter Peak Demand (MW)

Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)
2009	19,051	17,028
2010	18,137	17,904
2011	20,061	17,889
2012	19,249	16,881
2013	18,763	17,623
2014	18,692	19,784
2015	18,980	21,651
2016	19,538	18,948
2017	18,902	19,661
2018	19,244	21,232
2019	19,607	19,930
2020	20,258	18,908
2021	20,448	19,196
2022	20,709	19,656
2023	21,037	20,129
2024	21,433	20,575
2025	21,738	21,044
2026	22,048	21,609
2027	22,361	21,942
2028	22,678	22,440
2029	22,914	22,745
2030	23,109	23,169
2031	23,300	23,605
2032	23,479	23,868
2033	23,669	24,016
2034	23,869	24,295
2035	24,128	24,702
2036	24,389	25,116

Note: Historic (2009 - 2019); Projected (2020 - 2036)
Appendix 4G has been provided with the 2021 Company Load Forecast instead of the 2021 PJM Load Forecast because PJM does not provide forecasted sales or customer counts broken down by rate class.

Appendix 4H: Projected Summer & Winter Peak Load & Energy Forecast

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

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)[1]				(PROJECTED)														
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,528	16,599	16,356	16,808	16,901	17,121	17,298	17,464	17,520	17,590	17,662	17,693	17,726	17,791	17,871	17,964	18,057	18,124	18,175
1b. Additional Forecast																			
NCEMC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-119	-135	-74	-148	-181	-225	-213	-318	-344	-349	-288	-338	-367	-431	-430	-403	-415	-430	-500
3. Demand Response[2][5]	-58	-55	-54	-54	-46	-49	-68	-87	-99	-103	-105	-108	-112	-117	-121	-123	-125	-128	-131
4. Demand Response-Existing[2][3]	-2	-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Peak Adjustment	-	-	-																
6. Adjusted Load	16,409	16,464	16,282	16,661	16,720	16,895	17,084	17,145	17,176	17,242	17,373	17,355	17,359	17,360	17,442	17,561	17,643	17,695	17,676
7. % Increase in Adjusted Load (from previous year)	-3.4%	0.3%	-1.1%	2.3%	0.4%	1.0%	1.1%	0.4%	0.2%	0.4%	0.8%	-0.1%	0.0%	0.0%	0.5%	0.7%	0.5%	0.3%	-0.1%
B. Winter																			
1a. Base Forecast	17,792	16,842	14,661	14,469	16,901	17,121	17,298	17,464	17,520	17,590	17,662	17,693	17,726	17,791	17,871	17,964	18,057	18,124	18,175
1b. Additional Forecast																			
NCEMC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-119	-135	-14	-152	-200	-259	-294	-337	-302	-281	-321	-350	-363	-399	-342	-357	-391	-400	-414
3. Demand Response[2][4]	-6	-6	-6	-7	-17	-31	-46	-62	-77	-83	-85	-87	-90	-95	-100	-101	-103	-106	-109
4. Demand Response-Existing[2][3]	-1	-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Adjusted Load	17,673	16,707	14,647	14,317	16,701	16,862	17,004	17,127	17,218	17,309	17,341	17,343	17,363	17,392	17,530	17,606	17,666	17,724	17,761
6. % Increase in Adjusted Load	2.7%	-5.5%	-12.3%	-2.3%	16.7%	1.0%	0.8%	0.7%	0.5%	0.5%	0.2%	0.0%	0.1%	0.2%	0.8%	0.4%	0.3%	0.3%	0.2%
2. Energy (GWh)																			
A. Base Forecast	88,377	87,078	81,440	81,295	86,033	86,598	87,304	88,271	88,723	89,175	89,620	90,284	90,507	90,830	91,371	92,204	92,547	93,115	93,614
B. Additional Forecast																			
Future BTM[6]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Conservation & Demand Response[5]	-727	-801	-401	-858	-1,110	-1,409	-1,616	-1,740	-1,857	-1,923	-1,971	-2,031	-2,116	-2,208	-2,292	-2,347	-2,410	-2,524	-2,643
D. Demand Response-Existing[2][3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Adjusted Energy	87,650	86,277	81,039	80,437	84,923	85,189	85,688	86,531	86,866	87,252	87,648	88,253	88,391	88,622	89,078	89,857	90,137	90,591	90,971
F. % Increase in Adjusted Energy	-0.9%	-1.6%	-6.1%	-0.7%	5.6%	0.3%	0.6%	1.0%	0.4%	0.4%	0.5%	0.7%	0.2%	0.3%	0.5%	0.9%	0.3%	0.5%	0.4%

(1) Actual metered data.

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

(3) Existing DSM programs are included in the load forecast.

(4) Actual historical data based upon measured and verified EM&V results.

(5) Actual historical data based upon measured and verified EM&V results . Projected values represent modeled DSM firm capacity.

(6) Future behind the meter, which is not included in the base forecast

Appendix 4I: Required Reserve Margin

Company Name: Virginia Electric and Power Company

SCC Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)															
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
I. Reserve Margin(1)																			
1. Summer Reserve Margin																			
a. MW(1)	2,946	3,399	2,827	3,614	3,015	2,942	1,580	1,861	1,789	2,620	2,487	2,799	3,149	3,454	3,641	3,912	4,839	5,276	5,695
b. Percent of Load	17.8%	20.5%	17.3%	21.7%	18.0%	17.4%	9.2%	10.9%	10.4%	15.2%	14.3%	16.1%	18.1%	19.9%	20.9%	22.3%	27.4%	29.8%	32.2%
c. Actual Reserve Margin(2)	N/A	N/A	N/A	16.5%	16.9%	16.1%	8.0%	9.0%	8.4%	13.2%	12.7%	14.2%	16.0%	17.4%	18.4%	20.0%	25.1%	27.4%	29.4%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	5,876	3,555	3,166	1,289	1,256	830	1,381	1,304	1,294	1,512	1,674	1,726	1,888	2,610	2,815	2,963
b. Percent of Load	N/A	N/A	N/A	41.0%	21.3%	18.8%	7.6%	7.3%	4.8%	8.0%	7.5%	7.5%	8.7%	9.6%	9.8%	10.7%	14.8%	15.9%	16.7%
c. Actual Reserve Margin(2)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
II. Annual Loss-of-Load Hours(3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) To be calculated based on total net capability for summer and winter.

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

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

Appendix 4J: Summer and Winter Peak

Company Name: Virginia Electric and Power Company **SCC Schedule 5**

POWER SUPPLY DATA

	(ACTUAL)				(PROJECTED)														
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak[1]	16,409	16,464	16,282	16,661	16,720	16,895	17,084	17,145	17,176	17,242	17,373	17,355	17,359	17,360	17,442	17,561	17,643	17,695	17,676
b. Other Commitments[2]	119	135	74	148	181	225	213	318	344	349	288	338	367	431	430	403	415	430	500
c. Total System Summer Peak	16,528	16,599	16,356	16,808	16,901	17,121	17,298	17,464	17,520	17,590	17,662	17,693	17,726	17,791	17,871	17,964	18,057	18,124	18,175
d. Percent Increase in Total Summer Peak	-3.3%	0.4%	-1.5%	2.8%	0.6%	1.3%	1.0%	1.0%	0.3%	0.4%	0.4%	0.2%	0.2%	0.4%	0.5%	0.5%	0.5%	0.4%	0.3%
2. Winter																			
a. Adjusted Winter Peak[1]	17,673	16,707	14,647	14,317	16,701	16,862	17,004	17,127	17,218	17,309	17,341	17,343	17,363	17,392	17,530	17,606	17,666	17,724	17,761
b. Other Commitments[2]	119	135	14	152	200	259	294	337	302	281	321	350	363	399	342	357	391	400	414
c. Total System Winter Peak	17,792	16,842	14,661	14,469	16,901	17,121	17,298	17,464	17,520	17,590	17,662	17,693	17,726	17,791	17,871	17,964	18,057	18,124	18,175
d. Percent Increase in Total Winter Peak	2.8%	-5.3%	-12.9%	-1.3%	16.8%	1.3%	1.0%	1.0%	0.3%	0.4%	0.4%	0.2%	0.2%	0.4%	0.5%	0.5%	0.5%	0.4%	0.3%

(1) Adjusted load from Appendix 4H.

(2) Includes firm additional forecast, conservation efficiency, and peak adjustments from Appendix 4H.

Appendix 4K: Wholesale Power Sales Contracts

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

WHOLESALE POWER SALES CONTRACTS

Entity	Contract Length	Contract Type	2018 (Actual)	2019 (Actual)	2020 (Actual)	2021	2022 (Projected)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements(1)	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11	11	11
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements(1)	11	12	12	12	12	12	12	12	12	13	13	13	13	13	13	13	13	13	13
Virginia Municipal Electric Association	5/31/2031 with annual renewal	Full Requirements(1)	299	300	300	300	301	302	302	303	303	304	305	305	306	306	307	308	308	309	310

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

Appendix 4O: ICF RGGI + Federal CO_2 Price Forecast (Nominal $)

	Fuel Price					Power and REC Prices			RTO Capacity Prices		Emission Prices				
Year	Henry Hub Natural Gas ($/MMBtu)	Zone 5 Delivered Natural Gas ($/MMBtu)	CAPP CSX: 12,500 1%S FOB ($/MMBtu)	No. 2 Oil ($/MMBtu)	1% No.6 Oil ($/MMBtu)	PJM-DOM On-Peak ($/MWh)	PJM-DOM Off-Peak ($/MWh)	PJM Tier 1 REC Prices ($/MWh)	($/kW-yr)	($/MW-day)*	SO_2 ($/Ton)	CSAPR Ozone NO_x ($/Ton)	CSAPR Annual NO_x ($/Ton)	Federal CO2 Price ($/Ton)	RGGI CO_2 ($/Ton)
2021	3.66	3.88	2.54	15.33	11.28	42.67	28.96	14.53	41.45	113.55	2.40	2,850.00	2.00	0.00	8.50
2022	3.17	3.63	2.40	14.99	10.87	40.80	28.76	14.70	51.81	141.95	2.45	2,914.73	2.05	0.00	8.64
2023	2.92	3.13	2.27	13.50	9.97	36.04	27.41	14.70	53.84	147.50	2.34	1,911.03	2.75	0.00	7.13
2024	3.06	2.79	2.19	11.85	8.09	32.73	27.82	17.17	55.67	152.52	2.07	157.78	3.86	0.00	4.83
2025	3.12	2.62	2.23	11.95	7.93	31.85	27.29	16.05	57.46	157.42	2.02	52.43	4.03	0.00	4.62
2026	3.23	2.62	2.29	12.37	8.24	31.67	27.34	14.45	59.18	162.15	2.01	42.73	4.04	1.35	4.82
2027	3.34	2.69	2.35	12.84	8.59	31.55	27.47	12.21	60.93	166.94	2.02	33.01	4.03	1.44	5.03
2028	3.45	2.84	2.40	13.38	8.98	32.30	28.34	9.90	62.76	171.94	2.01	23.34	4.03	1.54	5.25
2029	3.57	2.96	2.46	13.96	9.42	33.11	29.24	7.32	64.65	177.11	2.01	13.68	4.03	1.64	5.49
2030	3.69	3.05	2.52	14.60	9.89	33.52	29.84	4.87	66.59	182.43	2.01	4.02	4.02	1.75	5.72
2031	3.80	3.18	2.59	15.27	10.39	34.32	30.79	5.11	68.56	187.82	2.00	4.02	4.02	1.87	5.99
2032	3.91	3.33	2.67	15.80	10.78	35.63	32.12	5.40	70.53	193.23	2.01	4.01	4.01	1.99	6.26
2033	4.02	3.50	2.74	16.13	11.02	36.88	33.47	5.75	72.53	198.73	2.01	4.01	4.01	2.12	6.54
2034	4.14	3.63	2.81	16.48	11.26	37.83	34.56	6.16	74.59	204.36	2.00	4.00	4.00	2.27	6.83
2035	4.26	3.76	2.89	16.83	11.50	38.62	35.55	6.64	76.71	210.17	2.00	3.99	3.99	2.42	7.13
2036	4.41	3.90	2.95	17.17	11.73	39.87	36.95	7.23	78.89	216.13	1.99	3.99	3.99	2.57	7.48

Note: *RTO capacity prices are restated in the units used by the PJM capacity market.

Note : CSAPR SO_2 and nationwide SO_2 prices are used as the SO_2 market price.

Appendix 4O: Commodity Price Forecast, Natural Gas

	Henry Hub Natural Gas ($/MMBtu)		
Year	RGGI + Federal CO_2 Commodity Forecast	RGGI + Federal CO_2 High Fuel Price Commodity Forecast	RGGI + Federal CO_2 Low Fuel Price Commodity Forecast
2021	3.66	3.66	3.66
2022	3.17	3.17	3.17
2023	2.92	3.34	2.83
2024	3.06	4.38	2.72
2025	3.12	4.83	2.63
2026	3.23	5.15	2.80
2027	3.34	5.47	2.98
2028	3.45	5.81	3.17
2029	3.57	6.17	3.37
2030	3.69	6.53	3.57
2031	3.80	6.81	3.68
2032	3.91	7.08	3.79
2033	4.02	7.37	3.91
2034	4.14	7.67	4.02
2035	4.26	7.97	4.14
2036	4.41	8.22	4.19

Appendix 4O: Commodity Price Forecast, Natural Gas

	Zone 5 Delivered Natural Gas ($/MMBtu)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	3.88	3.88	3.88
2022	3.63	3.63	3.63
2023	3.13	3.55	3.04
2024	2.79	4.11	2.45
2025	2.62	4.33	2.13
2026	2.62	4.55	2.20
2027	2.69	4.83	2.34
2028	2.84	5.20	2.56
2029	2.96	5.56	2.76
2030	3.05	5.89	2.93
2031	3.18	6.18	3.06
2032	3.33	6.50	3.21
2033	3.50	6.85	3.38
2034	3.63	7.16	3.52
2035	3.76	7.48	3.65
2036	3.90	7.70	3.67

Appendix 4O: Commodity Price Forecast, Coal (FOB)

	CAPP CSX: 12,500 1%S FOB ($/MMBtu)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	2.54	2.54	2.54
2022	2.40	2.40	2.40
2023	2.27	2.28	2.27
2024	2.19	2.21	2.19
2025	2.23	2.26	2.23
2026	2.29	2.31	2.29
2027	2.35	2.37	2.35
2028	2.40	2.43	2.40
2029	2.46	2.49	2.46
2030	2.52	2.55	2.52
2031	2.59	2.62	2.59
2032	2.67	2.69	2.66
2033	2.74	2.76	2.74
2034	2.81	2.83	2.81
2035	2.89	2.91	2.88
2036	2.95	2.97	2.95

Appendix 4O: Commodity Price Forecast, Oil

	No. 2 Oil ($/MMBtu)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	15.33	15.33	15.33
2022	14.99	14.99	14.99
2023	13.50	13.60	13.41
2024	11.85	12.16	11.42
2025	11.95	12.36	11.30
2026	12.37	12.81	11.25
2027	12.84	13.43	11.50
2028	13.38	14.00	12.05
2029	13.96	14.62	12.61
2030	14.60	15.38	13.36
2031	15.27	16.20	13.94
2032	15.80	16.82	14.35
2033	16.13	17.34	14.71
2034	16.48	17.89	15.16
2035	16.83	18.30	15.33
2036	17.17	18.62	15.63

Appendix 4O: Commodity Price Forecast, Oil

	1% No.6 Oil ($/MMBtu)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	11.28	11.28	11.28
2022	10.87	10.87	10.87
2023	9.97	10.05	9.89
2024	8.09	8.34	7.73
2025	7.93	8.27	7.41
2026	8.24	8.60	7.34
2027	8.59	9.06	7.50
2028	8.98	9.49	7.91
2029	9.42	9.95	8.33
2030	9.89	10.52	8.89
2031	10.39	11.15	9.32
2032	10.78	11.61	9.61
2033	11.02	11.99	9.87
2034	11.26	12.40	10.19
2035	11.50	12.68	10.29
2036	11.73	12.90	10.49

Appendix 4O: Commodity Price Forecast, On-Peak Power Price

	PJM-DOM On-Peak ($/MWh)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	42.67	42.67	42.67
2022	40.80	40.80	40.80
2023	36.04	37.89	34.98
2024	32.73	39.57	29.92
2025	31.85	41.55	28.47
2026	31.67	43.24	28.88
2027	31.55	45.10	29.35
2028	32.30	47.78	30.71
2029	33.11	50.47	32.15
2030	33.52	52.92	33.15
2031	34.32	54.71	33.95
2032	35.63	56.92	35.27
2033	36.88	59.17	36.56
2034	37.83	61.12	37.51
2035	38.62	62.97	38.29
2036	39.87	64.77	39.05

Appendix 4O: Commodity Price Forecast, Off-Peak Power Price

	PJM-DOM Off-Peak ($/MWh)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	28.96	28.96	28.96
2022	28.76	28.76	28.76
2023	27.41	29.19	26.51
2024	27.82	34.10	25.36
2025	27.29	35.99	24.26
2026	27.34	38.19	24.80
2027	27.47	40.62	25.46
2028	28.34	43.85	26.86
2029	29.24	47.18	28.33
2030	29.84	50.39	29.48
2031	30.79	52.55	30.44
2032	32.12	55.07	31.80
2033	33.47	57.70	33.19
2034	34.56	60.08	34.29
2035	35.55	62.43	35.28
2036	36.95	64.48	36.16

Appendix 4O: Commodity Price Forecast, PJM Tier 1 Renewable Energy Certificates

	PJM Tier 1 REC Prices ($/MWh)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	14.53	14.53	14.53
2022	14.70	14.70	14.70
2023	14.70	12.97	14.84
2024	17.17	8.05	17.86
2025	16.05	8.03	16.61
2026	14.45	8.38	14.81
2027	12.21	6.73	12.45
2028	9.90	5.04	10.03
2029	7.32	2.95	7.41
2030	4.87	2.08	4.97
2031	5.11	2.54	5.32
2032	5.40	3.13	5.74
2033	5.75	3.86	6.21
2034	6.16	4.74	6.75
2035	6.64	5.77	7.35
2036	7.23	6.84	8.08

Appendix 4O: Commodity Price Forecast, PJM RTO Capacity

	PJM RTO Capacity Prices ($/kW-yr)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	41.45	41.45	41.45
2022	51.81	50.27	52.11
2023	53.84	49.56	54.66
2024	55.67	48.53	57.05
2025	57.46	47.33	59.42
2026	59.18	45.96	61.28
2027	60.93	44.50	62.85
2028	62.76	42.99	64.49
2029	64.65	41.40	66.18
2030	66.59	39.73	67.92
2031	68.56	37.96	69.67
2032	70.53	36.08	71.42
2033	72.53	34.10	73.19
2034	74.59	32.03	75.00
2035	76.71	29.87	76.87
2036	78.89	31.68	79.89

Appendix 4O: Commodity Price Forecast, PJM RTO Capacity

	RTO Capacity Prices ($/MW-day)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	113.55	113.55	113.55
2022	141.95	137.73	142.77
2023	147.50	135.78	149.76
2024	152.52	132.95	156.30
2025	157.42	129.66	162.78
2026	162.15	125.91	167.90
2027	166.94	121.92	172.20
2028	171.94	117.78	176.69
2029	177.11	113.43	181.31
2030	182.43	108.86	186.07
2031	187.82	104.01	190.88
2032	193.23	98.85	195.66
2033	198.73	93.43	200.52
2034	204.36	87.75	205.48
2035	210.17	81.84	210.60
2036	216.13	86.80	218.87

Note: *RTO capacity prices are restated in the units used by the PJM capacity market.

Appendix 4O: Commodity Price Forecast, SO_2 Emission Allowances

	SO_2 (\$/Ton)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	2.40	2.40	2.40
2022	2.45	2.45	2.45
2023	2.34	2.34	2.34
2024	2.07	2.07	2.07
2025	2.02	2.02	2.02
2026	2.01	2.01	2.01
2027	2.02	2.02	2.02
2028	2.01	2.01	2.01
2029	2.01	2.01	2.01
2030	2.01	2.01	2.01
2031	2.00	2.00	2.00
2032	2.01	2.01	2.01
2033	2.01	2.01	2.01
2034	2.00	2.00	2.00
2035	2.00	2.00	2.00
2036	1.99	1.99	1.99

Note: CSAPR SO_2 and nationwide SO_2 prices are used as the SO_2 market price.

Appendix 4O: Commodity Price Forecast, NOx Emission Allowances

	CSAPR Ozone NOx ($/Ton)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	2,850.00	2850.00	2,850.00
2022	2,914.73	2914.73	2,914.73
2023	1,911.03	1911.03	1,911.03
2024	157.78	157.78	157.78
2025	52.43	52.43	52.43
2026	42.73	42.73	42.73
2027	33.01	33.01	33.01
2028	23.34	23.34	23.34
2029	13.68	13.68	13.68
2030	4.02	4.02	4.02
2031	4.02	4.02	4.02
2032	4.01	4.01	4.01
2033	4.01	4.01	4.01
2034	4.00	4.00	4.00
2035	3.99	3.99	3.99
2036	3.99	3.99	3.99

Appendix 4O: Commodity Price Forecast, NOx Emission Allowances

	CSAPR Annual NOx ($/Ton)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	2.00	2.00	2.00
2022	2.05	2.05	2.05
2023	2.75	2.75	2.75
2024	3.86	3.86	3.86
2025	4.03	4.03	4.03
2026	4.04	4.04	4.04
2027	4.03	4.03	4.03
2028	4.03	4.03	4.03
2029	4.03	4.03	4.03
2030	4.02	4.02	4.02
2031	4.02	4.02	4.02
2032	4.01	4.01	4.01
2033	4.01	4.01	4.01
2034	4.00	4.00	4.00
2035	3.99	3.99	3.99
2036	3.99	3.99	3.99

Appendix 4O: Commodity Price Forecast, CO_2

	Federal CO_2 ($/Ton)		
Year	RGGI + Federal CO2 Commodity Forecast	RGGI + Federal CO2 High Fuel Price Commodity Forecast	RGGI + Federal CO2 Low Fuel Price Commodity Forecast
2021	0.00	0.00	0.00
2022	0.00	0.00	0.00
2023	0.00	0.00	0.00
2024	0.00	0.00	0.00
2025	0.00	0.00	0.00
2026	1.35	5.76	1.96
2027	1.44	6.13	2.09
2028	1.54	6.55	2.22
2029	1.64	6.99	2.38
2030	1.75	7.47	2.53
2031	1.87	7.97	2.71
2032	1.99	8.50	2.89
2033	2.12	9.06	3.09
2034	2.27	9.66	3.29
2035	2.42	10.30	3.50
2036	2.57	10.98	3.73

Appendix 4O: Commodity Price Forecast, CO_2

	RGGI CO_2 (\$/Ton)		
Year	**RGGI + Federal CO2 Commodity Forecast**	**RGGI + Federal CO2 High Fuel Price Commodity Forecast**	**RGGI + Federal CO2 Low Fuel Price Commodity Forecast**
2021	8.50	8.50	8.50
2022	8.64	8.64	8.64
2023	7.13	6.62	7.29
2024	4.83	3.18	5.41
2025	4.62	2.68	5.31
2026	4.82	2.75	5.56
2027	5.03	2.82	5.82
2028	5.25	2.89	6.09
2029	5.49	2.97	6.38
2030	5.72	3.04	6.68
2031	5.99	3.12	7.01
2032	6.26	3.19	7.34
2033	6.54	3.28	7.70
2034	6.83	3.35	8.07
2035	7.13	3.43	8.46
2036	7.48	3.51	8.88

Appendix 5A: Existing Generation Units in Service

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.(1)	MW Summer
Altavista	Altavista, VA	Base	Biomass	Feb-1992	51
Bath County 1-6	Warm Springs, VA	Intermediate	Hydro-Pumped Storage	Dec-1985	1,808
Bear Garden	Buckingham County, VA	Intermediate	Natural Gas-CC	May-2011	622
Brunswick	Brunswick County, VA	Intermediate	Natural Gas-CC	May-2016	1,376
Chesapeake CT 1, 4, 6	Chesapeake, VA	Peak	Light Fuel Oil	Dec-1967	39
Chesterfield 5	Chester, VA	Base	Coal	Aug-1964	336
Chesterfield 6	Chester, VA	Base	Coal	Dec-1969	678
Chesterfield 7	Chester, VA	Intermediate	Natural Gas-CC	Jun-1990	197
Chesterfield 8	Chester, VA	Intermediate	Natural Gas-CC	May-1992	195
Clover 1	Clover, VA	Base	Coal	Oct-1995	220
Clover 2	Clover, VA	Base	Coal	Mar-1996	219
Colonial Trail West	Surry, VA	Intermittent	Renewable	Dec-2019	51
CVOW	Virginia Beach, VA	Intermittent	Renewable	Oct-2020	3
Darbytown 1	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84
Darbytown 2	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84
Darbytown 3	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84
Darbytown 4	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84
Elizabeth River 1	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	110
Elizabeth River 2	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	110
Elizabeth River 3	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	110
Gaston Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Feb-1963	220
Gordonsville 1	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109
Gordonsville 2	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109
Gravel Neck 1-2	Surry, VA	Peak	Light Fuel Oil	Aug-1970	28
Gravel Neck 3	Surry, VA	Peak	Natural Gas-Turbine	Oct-1989	85
Gravel Neck 4	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85
Gravel Neck 5	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85
Gravel Neck 6	Surry, VA	Peak	Natural Gas-Turbine	Nov-1989	85
Greensville	Brunswick County, VA	Intermediate	Natural Gas-CC	Dec-2018	1,588
Hopewell	Hopewell, VA	Base	Biomass	Jul-1989	51
Ladysmith 1	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151
Ladysmith 2	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151
Ladysmith 3	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	161
Ladysmith 4	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	160
Ladysmith 5	Woodford, VA	Peak	Natural Gas-Turbine	Apr-2009	160
Lowmoor CT 1-4	Covington, VA	Peak	Light Fuel Oil	Jul-1971	48
Mount Storm 1	Mt. Storm, WV	Base	Coal	Sep-1965	548
Mount Storm 2	Mt. Storm, WV	Base	Coal	Jul-1966	553
Mount Storm 3	Mt. Storm, WV	Base	Coal	Dec-1973	520
Mount Storm CT	Mt. Storm, WV	Peak	Light Fuel Oil	Oct-1967	11
North Anna 1	Mineral, VA	Base	Nuclear	Jun-1978	838
North Anna 2	Mineral, VA	Base	Nuclear	Dec-1980	834
North Anna Hydro	Mineral, VA	Intermediate	Hydro-Conventional	Dec-1987	1
Northern Neck CT 1-4	Warsaw, VA	Peak	Light Fuel Oil	Jul-1971	47
Possum Point 6	Dumfries, VA	Intermediate	Natural Gas-CC	Jul-2003	573
Possum Point CT 1-6	Dumfries, VA	Peak	Light Fuel Oil	May-1968	72
Remington 1	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	153
Remington 2	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	151

Appendix 5A: Existing Generation Units in Service

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.(1)	MW Summer
Remington 3	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152
Remington 4	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152
Roanoke Rapids Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Sep-1955	95
Rosemary	Roanoke Rapids, NC	Peak	Light Fuel Oil	Dec-1990	165
Scott Solar	Powhatan, VA	Intermittent	Renewable	Dec-2016	6
Spring Grove	Surry, VA	Intermittent	Renewable	Nov-2020	35
Solar Partnership Program	Distributed	Intermittent	Renewable	Jan-2012	2
Southampton	Franklin, VA	Base	Biomass	Mar-1992	51
Surry 1	Surry, VA	Base	Nuclear	Dec-1972	838
Surry 2	Surry, VA	Base	Nuclear	May-1973	838
Virginia City Hybrid Energy Center	Virginia City, VA	Intermediate	Coal	Jul-2012	610
Warren	Front Royal, VA	Intermediate	Natural Gas-CC	Dec-2014	1,370
Whitehouse Solar	Louisa, VA	Intermittent	Renewable	Dec-2016	7
Woodland Solar	Isle of Wight, VA	Intermittent	Renewable	Dec-2016	7
Yorktown 3	Yorktown, VA	Peak	Heavy Fuel Oil	Dec-1974	790
Subtotal - Base					6,575
Subtotal - Intermediate					8,873
Subtotal - Peak					3,597
Subtotal - Intermittent					110
Total					19,156

Note: Summer MW for solar generation represents firm capacity at ownership.

(1) Commercial operation date

Appendix 5B: Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units[1]					
W. E. Partners II	NC	Biomass	300	3/15/2012	Auto renew
W. E. Partners 1	NC	Biomass	100	4/26/2013	Auto renew
Weyerhaeuser/Domtar	NC	Coal/biomass	28,400[2]	7/27/1991	Auto renew
3620 Virginia Dare Trail N	NC	Solar	4	9/14/2009	Auto renew
Plymouth Solar	NC	Solar	5,000	10/4/2012	10/3/2027
Dogwood Solar	NC	Solar	20,000	12/9/2014	12/8/2029
HXOap Solar	NC	Solar	20,000	12/16/2014	12/15/2029
Bethel Price Solar	NC	Solar	5,000	12/9/2014	12/8/2029
Jakana Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Lewiston Solar	NC	Solar	5,000	12/18/2014	12/17/2029
Williamston Solar	NC	Solar	5,000	12/4/2014	12/3/2029
Windsor Solar	NC	Solar	5,000	12/17/2014	12/16/2029
510 REPP One Solar	NC	Solar	1,250	3/11/2015	3/10/2030
Everetts Wildcat Solar	NC	Solar	5,000	3/11/2015	3/10/2030
SolNC5 Solar	NC	Solar	5,000	5/12/2015	5/11/2030
Creswell Aligood Solar	NC	Solar	14,000	5/13/2015	5/12/2030
Two Mile Desert Road - SolNC1	NC	Solar	5,000	8/10/2015	8/9/2030
SolNCPower6 Solar	NC	Solar	5,000	11/1/2015	10/31/2030
Downs Farm Solar	NC	Solar	5,000	12/1/2015	11/30/2030
GKS Solar- SolNC2	NC	Solar	5,000	12/16/2015	12/15/2030
Windsor Cooper Hill Solar	NC	Solar	5,000	12/18/2015	12/17/2030
Green Farm Solar	NC	Solar	5,000	1/6/2016	1/5/2031
FAE X - Shawboro	NC	Solar	20,000	1/26/2016	1/25/2031
FAE XVII - Watson Seed	NC	Solar	20,000	1/28/2016	1/27/2031
Bradley PVI- FAE IX	NC	Solar	5,000	2/4/2016	2/3/2031
Conetoe Solar	NC	Solar	5,000	2/5/2016	2/4/2031
SolNC3 Solar-Sugar Run Solar	NC	Solar	5,000	2/5/2016	2/4/2031
Gates Solar	NC	Solar	5,000	2/8/2016	2/7/2031
Long Farm 46 Solar	NC	Solar	5,000	2/12/2016	2/11/2031
Battleboro Farm Solar	NC	Solar	5,000	2/17/2016	2/16/2031
Winton Solar	NC	Solar	5,000	2/8/2016	2/7/2031
SolNC10 Solar	NC	Solar	5,000	1/13/2016	1/12/2031
Tarboro Solar	NC	Solar	5,000	12/31/2015	12/30/2030
Bethel Solar	NC	Solar	4,400	3/3/2016	3/2/2031
Garysburg Solar	NC	Solar	5,000	3/18/2016	3/17/2031
Woodland Solar	NC	Solar	5,000	4/7/2016	4/6/2031
Gaston Solar	NC	Solar	5,000	4/18/2016	4/17/2031
TWE Kelford Solar	NC	Solar	4,700	6/6/2016	6/5/2031
FAE XVIII - Meadows	NC	Solar	20,000	6/9/2016	6/8/2031
Seaboard Solar	NC	Solar	5,000	6/29/2016	6/28/2031
Simons Farm Solar	NC	Solar	5,000	7/13/2016	7/12/2031
Whitakers Farm Solar	NC	Solar	3,400	7/20/2016	7/19/2031
MC1 Solar	NC	Solar	5,000	8/19/2016	8/18/2031
Williamston West Farm Solar	NC	Solar	5,000	8/23/2016	8/22/2031
River Road Solar	NC	Solar	5,000	8/23/2016	8/22/2031
White Farm Solar	NC	Solar	5,000	8/26/2016	8/25/2031
Hardison Farm Solar	NC	Solar	5,000	9/9/2016	9/8/2031
Modlin Farm Solar	NC	Solar	5,000	9/14/2016	9/13/2031
Battleboro Solar	NC	Solar	5,000	10/7/2016	10/6/2031
Williamston Speight Solar	NC	Solar	15,000	11/23/2016	11/22/2031

Appendix 5B: Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units[1]					
Barnhill Road Solar	NC	Solar	3,100	11/30/2016	11/29/2031
Hemlock Solar	NC	Solar	5,000	12/5/2016	12/4/2031
Leggett Solar	NC	Solar	5,000	12/14/2016	12/13/2031
Schell Solar Farm	NC	Solar	5,000	12/22/2016	12/21/2031
FAE XXXV - Turkey Creek	NC	Solar	13,500	1/31/2017	1/30/2027
FAE XXII - Baker PVI	NC	Solar	5,000	1/30/2017	1/29/2032
FAE XXI -Benthall Bridge PVI	NC	Solar	5,000	1/30/2017	1/29/2032
Aulander Hwy 42 Solar	NC	Solar	5,000	12/30/2016	12/29/2031
Floyd Road Solar	NC	Solar	5,000	6/19/2017	6/18/2032
Flat Meeks- FAE II	NC	Solar	5,000	10/27/2017	10/26/2032
HXNAir Solar One	NC	Solar	5,000	12/21/2017	12/20/2032
Cork Oak Solar	NC	Solar	20,000	12/29/2017	12/28/2027
Sunflower Solar	NC	Solar	16,000	12/29/2017	12/28/2027
Davis Lane Solar	NC	Solar	5,000	12/31/2017	12/30/2032
FAE XIX- American Legion PVI	NC	Solar	15,840	1/2/2018	1/1/2033
FAE XXV-Vaughn's Creek	NC	Solar	20,000	1/2/2018	1/1/2033
TWE Ahoskie Solar Project	NC	Solar	5,000	1/12/2018	1/11/2033
Cottonwood Solar	NC	Solar	3,000	1/25/2018	1/24/2033
Shiloh Hwy 1108 Solar	NC	Solar	5,000	2/9/2018	2/8/2033
Chowan Jehu Road Solar	NC	Solar	5,000	2/9/2018	2/8/2033
Phelps 158 Solar Farm	NC	Solar	5,000	2/26/2018	2/25/2033
Sandy Solar	NC	Solar	5,000	5/30/2018	5/29/2033
Northern Cardinal Solar	NC	Solar	2,000	6/29/2018	6/28/2033
Carl Friedrich Gauss Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Sun Farm VI Solar	NC	Solar	4,975	9/10/2018	9/9/2033
Sun Farm V Solar	NC	Solar	4,975	9/10/2018	9/9/2033
Citizens Hertford	NC	Solar	16,200	6/6/2019	6/5/2029
Camden Dam Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Mill Pond Solar	NC	Solar	5,000	9/10/2018	9/9/2033
Jamesville Road	NC	Solar	5,000	9/10/2018	9/9/2033
North 301	NC	Solar	20,000	12/18/2019	12/17/2029
Five Forks	NC	Solar	20,000	12/23/2019	12/22/2029
Whitehurst PVI Solar	NC	Solar	10,000	3/13/2020	3/12/2035
FAE XXXIII - Grandy	NC	Solar	20,000	3/13/2020	3/12/2030
Alpha Value Solar	NC	Solar	5,000	7/9/2020	9/9/2033
FAE XXXIV - Underwood	NC	Solar	16,000	10/23/2020	10/22/2030
Highway -158 PVI	NC	Solar	9,000	11/10/2020	11/9/2030
Gliden Solar	NC	Solar	5,000	12/30/2020	12/29/2035
Sun Farm VIII	NC	Solar	3,975	12/17/2020	9/9/2033
MeadWestvaco (formerly Westvaco)	VA	Coal/Biomass	140,000	11/3/1982	8/25/2028
Smurfit-Stone Container	VA	Coal/biomass	48,400[3]	3/21/1981	Auto renew
Brasfield Dam	VA	Hydro	2,800	10/12/1993	Auto renew
Columbia Mills	VA	Hydro	343	2/7/1985	Auto renew
Lakeview (Swift Creek) Dam	VA	Hydro	400	11/26/2008	Auto renew
Banister Dam	VA	Hydro	1,785	9/28/2008	Auto renew
Burnshire Dam	VA	Hydro	100	7/11/2016	Auto renew
Cushaw Hydro	VA	Hydro	5,500	11/21/2018	11/20/2033
Suffolk Landfill	VA	Methane	3,280	8/1/2020	7/31/2025
Alexandria/Arlington - Covanta	VA	MSW	21,000	1/29/1988	1/28/2023
Essex Solar Center	VA	Solar	20,000	12/14/2017	12/13/2037

Appendix 5B: Other Generation Units

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

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Primary Fuel Type	kW Summer	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units(1)					
Rives Road Solar	VA	Solar	19,700	5/15/2020	5/14/2033
Pamplin Solar	VA	Solar	15,700	7/13/2020	7/12/2033
Hickory Solar	VA	Solar	32,000	9/8/2020	9/7/2033

(1) Achieved commercial operation as of April 30, 2021; Generating facilities that have contracted directly with the Company.

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

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

Appendix 5J: Potential Unit Retirements for Plan B

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

UNIT PERFORMANCE DATA

Planned Unit Retirements(1)

Unit Name	Location	Unit Type	Primary Fuel Type	Projected Retirement Year	MW Summer	MW Winter
Chesapeake CT 1	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**15**	**20**
Chesapeake GT1					15	
Chesapeake CT 2	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**24**	**33**
Chesapeake GT4					12	
Chesapeake GT6					12	
Lowmoor CT	**Covington, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**48**	**65**
Lowmoor GT1					12	
Lowmoor GT2					12	
Lowmoor GT3					12	
Lowmoor GT4					12	
Mount Storm CT	**Mt. Storm, WV**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**11**	**15**
Mt. Storm GT1					11	
Northern Neck CT	**Warsaw, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2022**	**47**	**63**
Northern Neck GT1					12	
Northern Neck GT2					11	
Northern Neck GT3					12	
Northern Neck GT4					12	
Possum Point CT	**Dumfries, VA**	**Steam-Cycle**	**Light Fuel Oil**	**2022**	**72**	**106**
Possum Point CT1					12	
Possum Point CT2					12	
Possum Point CT3					12	
Possum Point CT4					12	
Possum Point CT5					12	
Possum Point CT6					12	
Yorktown 3	**Yorktown, VA**	**Steam-Cycle**	**Heavy Fuel Oil**	**2023**	**790**	**792**
Chesterfield 5	**Chester, VA**	**Steam-Cycle**	**Coal**	**2023**	**336**	**342**
Chesterfield 6	**Chester, VA**	**Steam-Cycle**	**Coal**	**2023**	**678**	**690**
Clover 1	**Clover, VA**	**Steam-Cycle**	**Coal**	**2025**	**220**	**222**
Clover 2	**Clover, VA**	**Steam-Cycle**	**Coal**	**2025**	**219**	**219**
Rosemary	**Roanoke Rapids, NC**	**Combine Cycle**	**Fuel Oil**	**2027**	**165**	**165**
Altavista	**Altavista, VA**	**Steam-Cycle**	**Biomass**	**2028**	**51**	**51**
Hopewell	**Hopewell, VA**	**Steam-Cycle**	**Biomass**	**2028**	**51**	**51**
Southampton	**Franklin, VA**	**Steam-Cycle**	**Biomass**	**2028**	**51**	**51**

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

Appendix 6A: Description of Active DSM Programs

Air Conditioner Cycling Program

Branded Name:	Smart Cooling Rewards
State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Peak-Shaving
NC Program Type:	Peak-Shaving
VA Duration:	2010 – 2045
NC Duration:	2011 – 2045

Program Description:

This Program provides participants with an external radio frequency cycling switch that operates on central air conditioners and heat pump systems. Participants allow the Company to cycle their central air conditioning and heat pump systems during peak load periods. The cycling switch is installed by a contractor and located on or near the outdoor air conditioning unit(s). The Company remotely signals the unit when peak load periods are expected, and the air conditioning or heat pump system is cycled off and on for short intervals.

Program Marketing:
The Company uses business reply cards, online enrollment, and call center services.

Non-Residential Distributed Generation Program

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

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

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

Residential Appliance Recycling Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

Program Description:
This Program provides incentives to eligible residential customers to recycle specific types of qualifying freezers and refrigerators that are of specific of age and size. Appliance pick-up and proper recycling services are included.

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

Residential Efficient Products Marketplace Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

Program Description:
This Program provides eligible residential customers an incentive to purchase specific energy efficient appliances with a rebate through an online marketplace and through participating retail stores. The program offers rebates for the purchase of specific energy efficient appliances, including lighting efficiency upgrades such as A-line bulbs, reflectors, decoratives, globes, retrofit kit and fixtures, as well as other appliances such as freezers, refrigerators, clothes washers, dehumidifiers, air purifiers, clothes dryers, and dishwashers.

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

Residential Home Energy Assessment Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2019 – 2045
NC Duration:	2020 – 2045

Program Description:
This Program provides qualifying residential customers with an incentive to install a variety of energy saving measures following completion of a walk-through home energy assessment. The energy saving measures include replacement of existing light bulbs with LED bulbs, heat pump tune-up, duct insulation/sealing, fan motors upgrades, installation of efficient faucet aerators and showerheads, water heater turndown, replacement of electric domestic hot water with heat pump water heater, heat pump upgrades (ducted and ductless),

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

Non-Residential Lighting Systems & Controls Program

Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2019 – 2045
NC Duration: 2020 – 2045

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

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

Non-Residential Heating and Cooling Efficiency Program
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2019 – 2045
NC Duration: 2020 – 2045

Program Description:
This Program provides qualifying non-residential customers with incentives to implement new and upgrade existing high efficiency heating and cooling system equipment to more efficient HVAC technologies that can produce verifiable savings.

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

Non-Residential Window Film Program
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2019 – 2045
NC Duration: 2020 – 2045

Program Description:
This Program provides qualifying non-residential customers with incentives to install solar reduction window film to lower their cooling bills and improve occupant comfort.

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

Non-Residential Small Manufacturing Program
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2019 – 2045
NC Duration: 2020 – 2045

Program Description:
This Program provides qualifying non-residential customers with incentives for the installation of energy efficiency improvements, consisting of primarily compressed air systems measures for small manufacturing facilities.

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

Non-Residential Office Program
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2019 – 2045
NC Duration: 2020 – 2045

Program Description:
This Program provides qualifying non-residential customers with incentives for the installation of energy efficiency improvements, consisting of recommissioning measures at smaller office facilities.

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

Residential Customer Engagement Program
Target Class: Residential
VA Program Type: Energy Efficiency
VA Duration: 2021-2046

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

Appendix 6A: Description of Active DSM Programs

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

Residential Smart Thermostat Program (DR)

Target Class:	Residential
VA Program Type:	Demand Response
NC Program Type:	Demand Response
VA Duration:	2021-2046
NC Duration:	2022-2046

Program Description:

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

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

Residential Smart Thermostat Program (EE)

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2021-2046
NC Duration:	2022-2046

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

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

Residential Energy Efficient Kits Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2021-2046
NC Duration:	2022-2046

Program Description:
The Residential Energy Efficiency Kits Program would provide residential customers with new customer accounts the opportunity to receive Welcome Kits. The Welcome kit will initially include a Tier I advanced power strip and an educational insert informing customers about opportunities to manage their energy use and how to opt into receiving additional free measures by going online to the program website or calling the program hotline.

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

Residential Home Retrofit Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2021-2046
NC Duration:	2022-2046

Program Description:

The Residential Home Retrofit Program would target high users of electricity within the Company's Virginia service territory with an incentive to conduct a comprehensive and deep whole house diagnostic home energy assessment by BPI certified whole house building technicians. The diagnostic-driven audit will typically take between 2 ½ and 4 hours depending on home size, and will include: visual inspection of all areas of the home including attic and crawl spaces; blower door testing of envelope leakage; duck blaster equivalent testing of ducting system if present; line logger testing of major appliances; thermal imaging where required; physical measurements of key spaces and insulation levels; and efficiency determinations of major equipment.

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

Small Business Improvement Enhanced Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2021-2046
NC Duration:	2022-2046

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

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

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

Non-Residential New Construction Program
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2021-2046
NC Duration: 2022-2046

Program Description:
The Non-Residential New Construction Program would provide qualifying facility owners with incentives to install energy efficient measures in their new construction project. Program engineers will determine what potential energy efficiency upgrades are of interest to the owner and feasible within their budget. These measures coupled with basic facility design data will be analyzed to determine the optimized building design. This in-depth analysis will be performed using building energy simulation models, which will allow for ' bundles' of measures to be tested for potential energy savings gains from interactive effects. The results will be presented to the facility owner to determine which measures(s) are to be installed.

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

Residential Electric Vehicle (EE & DR)
Target Class: Residential
VA Program Type: Energy Efficiency/Demand Response
VA Duration: 2021-2046

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

Residential Electric Vehicle (Peak Shaving)
Target Class: Residential
VA Program Type: Peak Shaving
VA Duration: 2021-2046

Program Description:
The Residential Electric Vehicle Peak Shaving Program is for customers who already have a qualifying Level 2 charger and wish to participate in the demand response component only (no purchase incentive).

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

Residential Manufactured Housing
Target Class: Residential
VA Program Type: Energy Efficiency
VA Duration: 2021-2046

Program Description:
The Residential Manufactured Housing Program would provide residential customers in manufactured housing with educational assistance and an incentive to install energy efficiency measures. The auditor will perform a walk-through audit covering the envelope and all energy systems in the home, paying particular attention to the condition of DHW and HVAC systems, levels of insulation, and the condition of belly board.

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

Residential New Construction
Target Class: Residential
VA Program Type: Energy Efficiency
VA Duration: 2021-2046

Program Description:

The Program will provide incentives to home builders for the construction of new homes that are ENERGY STAR certified by directly recruiting existing networks of homebuilders and Home Energy Rating System Raters to build and inspect ENERGY STAR Certified New Homes. ENERGY STAR certification requires that homes be efficient at the system level and involves a whole-house set of standards that ensure homes are at least 15% more efficient than a home built to state-level minimum codes. Key components include: Shell improvements, HVAC performance, proper ventilation requirements and durability (proper weather sealing, flashing details, site and foundation details). Participating homes must submit an energy model developed using Ekotrope or REM/Rate energy modeling software, along with a copy of the home's ENERGY STAR certificate (both provided by the rater) in order to qualify for an incentive.

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

Residential/Non-Residential Multifamily
Target Class: Residential / Non-Residential
VA Program Type: Energy Efficiency
VA Duration: 2021-2046

Program Description:
The Program is designed to encourage investment in both residential and commercial (i.e., common spaces) within multi-family properties. The program design is based on a whole building

approach where the implementation vendor will identify as many cost-effective measure opportunities as possible in the entire building and encourage property owners to address the measures as a bundle. This approach provides a one- stop- shop program for multi-family property owners with solutions to include direct install-in-unit measures, incentives for prescriptive efficiency improvements, and access to project improvements for both in-unit and commercial common areas. Furthermore, the Program will identify, track and report residential and commercial savings separately according to the account type.

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

Non-Residential Midstream Energy Efficient Products

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
VA Duration:	2021-2046

Program Description:

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

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

House Bill 2789 (Heating and Cooling/Health and Safety)

Target Class:	Residential
VA Program Type:	Energy Efficiency
VA Duration:	2021-2046

Program Description:
This Program, the first of two programs consistent with the directives contained in Virginia House Bill 2789 (2019 Session), would offer incentives for the installation of measures that reduce residential heating and cooling costs and enhance the health and safety of residents, including repairs and improvements to home heating and cooling systems and installation of energy-saving measures in the house, such as insulation and air sealing. The Program's eligibility is limited based on income, age, and disability status.

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

Appendix 6F: Description of Proposed Phase IX DSM Programs

Residential Income and Age Qualifying
Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: Proposed
NC Duration: Future

Program Description:

The Residential Income and Age Qualifying Program would provide income and age qualifying residential customers with in-home energy assessments and installation of select energy-saving measures at no cost to eligible participants As with the Company's other low-income programs, the Company will partner with Weatherization Assistance Providers (WSPs) to perform community outreach and install program measures to eligible customers.

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

Residential Water Savings
Target Class: Residential
VA Program Type: Energy Efficiency/Demand Response
NC Program Type: Energy Efficiency/Demand Response
VA Duration: Proposed
NC Duration: Future

Program Description:

The Residential Water Savings Program would provide incentives to residential customers for the installation of smart communicating water heating and pool pump technologies, leveraging the energy efficiency and demand response savings opportunities of both technologies. All residential customers who purchase a qualifying heat pump water heater or a variable speed pool pump would receive an incentive (i.e., the energy efficiency component of the Program). Those customers would then be offered the opportunity to enroll in the demand response ("DR") component of the Program. Customers who already have a qualifying product noted above, could choose to participate in the peak reduction component of the Program, which can be called year-round. Customers would be allowed to opt out of a certain number of events.

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

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

Program Description:
The Residential Smart Home Program would offer the Company's residential customers a full suite of smart home products that provide seamless integration into their homes. The Program would provide incentives to residential customers who purchase smart control technologies. Customers will be offered two types of smart home kits to choose from – with and without a smart thermostat.

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

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

Program Description:
The Residential Virtual Audit would offer the Company's residential customers the opportunity to participate in an online, self-directed home energy assessment. The energy assessment would be completed entirely by the customer, with no trade ally entering the home. Customers who complete the self-assessment would then be given the opportunity to

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

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

Program Description:
The Non-Residential Agricultural would provide financial incentives for the installation of specific high-efficiency equipment for qualifying agribusiness operations. The financial incentives and technical assistance would be offered through prescriptive rebates and custom rebates.

Program Marketing:

Appendix 6F: Description of Proposed Phase IX DSM Programs

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

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

Program Description:
The Non-Residential Building Automation Program would capture energy savings associated with supporting the installation of new building automation systems in facilities that do not have centralized controls or that have an antiquated system that requires full replacement. The proposed program design is flexible in that the incentives can be paid to end customers or controls contractors, meeting the needs of individual project situations.

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

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

Program Description:
The Non-Residential Building Optimization would seek to capture energy savings through control system audits and tune-up measures in facilities with building energy management systems.

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

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

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

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

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

Program Description:
The Non-Residential Enhanced Prescriptive Program would be a replacement to the DSM Phase VI Non-Residential Prescriptive Program. The Program would provide qualifying non-residential customers with financial incentives for the installation of refrigeration, commercial kitchen equipment, HVAC improvements and maintenance, and installation of other

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

House Bill 2789 (Solar Component) Program
Target Class: Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: Proposed
NC Duration: Future

Program Description:
The HB 2789 (Solar Component) Program, consistent with the directives contained in Virginia House Bill 2789 (2019 Session), and as amended in the 2020 session, would offer incentives to participants of the first component HB 2789 (Heating and Cooling/Health and Safety), as well as eligible participants that have installed heating or cooling measures from other prior or future Company-sponsored DSM Programs, for the installation of equipment to generate electricity from sunlight. The Program's eligibility is limited based on income,

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

Appendix 7A: List of Transmission Lines Under Construction

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Dulles 230 kV Delivery - Add 6th Transformer	230	Aug-21	VA	0.6
Northern Neck Transformer #4 Replacement	230	Aug-21	VA	1.7
Winterpock 230 kV Delivery and 230 kV Ring Bus	230	Aug-21	VA	8.5
Dawson's Crossroads – Delivery Point (HEMC)	115	Aug-21	NC	0.7
Line #247 Suffolk to Swamp Rebuild	230	Sep-21	VA/NC	31.0
Waxpool 230 kV Delivery - Add 3rd Transformer	230	Nov-21	VA	0.5
Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230 kV Lines and New 230 kV Substation	230	Nov-21	VA	176.0
Varina 230 kV Delivery	230	Nov-21	VA	1
Pacific 230 kV Delivery – Add 4th Transformer	230	Nov-21	VA	0.4
Clover Substation – New 500 kV STATCOM and Rawlings Switching Station – New 500 kV STATCOM	500	Nov-21	VA	47.0
Line #49 New Road to Middleburg Rebuild	115	Dec-21	VA	12.7
Line #65 Norris Bridge Rebuild	115	Dec-21	VA	103.0
Line #120 Dozier to Thompsons Corner Partial Rebuild	115	Dec-21	VA	12.6
Line #127 Buggs Island to Plywood Rebuild	115	Dec-21	VA	42.4
Line #16 Great Bridge to Hickory and Line #74 Chesapeake Energy Center to Great Bridge Rebuild	115	Dec-21	VA	27.0
New Switching Station to Retire Line #139 Everetts to Windsor DP; Hoggard Mill Substation (new station)	230/115	Dec-21	NC	11.5
Line #2173 – Loudoun to Elklick Rebuild	230	Dec-21	VA	13.5
Line #2008 Partial Rebuild and Line #156 Retirement	230/115	Dec-21	VA	14.5
Chase City 115 kV Delivery - Add 2nd Transformer	115	Dec-21	VA	0.5
Line #128 Rebuild Mt. Jackson – SVEC	115	Dec-21	VA	13.1
Plaza 230 kV Delivery – Upgrade Transformer	230	Dec-21	VA	0.5
Rollins Ford 230 kV Delivery	230	Dec-21	VA	10
Paragon Park 230 kV Delivery – DEV	230	Jun-22	VA	2.5
Line #274 Pleasant View to Beaumeade Rebuild	230	Jun-22	VA	10.0
Line #2001 Possum Point to Occoquan Reconductor and Uprate	230	Jun-22	VA	4.7
Line #43 Staunton – Harrisonburg Rebuild	115	Jun-22	VA	39.6
Line #2175 Idylwood to Tysons – New 230 kV Line and Rebuild Tysons with GIS	230	Dec-22	VA	181.8
Line #552 Bristers to Chancellor Rebuild	500	Dec-22	VA	62.2
Line #295 and Partial Line #265 Rebuild	230	Dec-22	VA	15.5
Waxpool 230 kV Delivery – Add 4th Transformer	230	Mar-23	VA	0.4
Line #550 Mount Storm to Valley Rebuild	500	Dec-23	WV/VA	288.2
Line #34 Skiffes Creek to Yorktown and Line #61 Whealton to Yorktown Partial Rebuild and Fort Eustis Tap Rebuild	115	Dec-23	VA	24.2
Idylwood – Convert Straight Bus to Breaker-and-a-Half	230	Dec-26	VA	159.0

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PUBLIC VERSION

September 1, 2021

BY ELECTRONIC DELIVERY

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

Commonwealth of Virginia, ex rel. State Corporation Commission,
In re: Virginia Electric and Power Company's 2021 Update to its Integrated Resource Plan
pursuant to Va. Code 56-597 et seq.
Case No. PUR-2021-00201

Dear Mr. Logan:

Please find enclosed for electronic filing in the above-captioned proceeding the **public version** of Virginia Addendum 1 to the 2021 update to the 2020 Integrated Resource Plan of Virginia Electric and Power Company. An extraordinarily sensitive (redacted) version is also being filed under seal under separate cover.

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

Very truly yours,

/s/ Vishwa B. Link

Vishwa B. Link

Enclosure

cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.
Paul E. Pfeffer, Esq.
Audrey T. Bauhan, Esq.
Sarah R. Bennett, Esq.

Consolidated Bill Analysis

The Company completed a consolidated bill analysis for each Alternative Plan presented in the 2021 Update. This analysis encompasses three different customer classes and spans 2021 through 2035.

The Company calculated projected bills for each customer class under each Alternative Plan based on requirements set by the SCC ("Directed Methodology"). These requirements dictate that the Company use constant class allocation factors across time and no sales growth, either at the system or class level, in its calculations. As discussed in prior proceedings, the Company believes that this methodology results in overstated bill projections because it does not reflect anticipated growth in sales over the 15-year period on which each build plan is based.

Under the Directed Methodology, all Alternative Plans also assume a capacity factor for existing and future solar resources of 21.2%—the three-year historical average of solar tracking facilities in Virginia. As discussed in prior proceedings, the Company believes that a projected capacity factor for future solar facilities better reflects their long-term output and has therefore incorporated such capacity factors into one of the sensitivities presented in Section 2.6.

Given these concerns with the Directed Methodology, the Company has also calculated projected bills under each Alternative Plan using (i) forecasted system and class sales growth, and the associated class allocation factors and (ii) a 25.4% capacity factor for solar resources ("Company Methodology").

The electric bill of the Company's typical residential customer in Virginia (*i.e.*, one which uses 1,000 kWh per month) was $122.66 as of December 31, 2019. As of May 1, 2020, this typical bill was $116.18, with the decrease largely attributable to a significant reduction in the fuel factor. Figure 2.5.1 presents the summary results of typical residential customer bill projections under both the Company Methodology and the Directed Methodology based on Alternative Plan B for 2030 and 2035.

Figure 2.5.1 shows that, when using the Company Methodology and a baseline of May 1, 2020, the typical residential customer's bill is expected to increase at a compound annual growth rate ("CAGR") of 2.5% over the next 15 years. When using the Company Methodology and December 31, 2019 as the baseline, the projected increase in the typical residential customer's bill is approximately 2.1% on a compound annual basis.

As an additional point of comparison, in July 2008—the year following passage of the Virginia Electric Utility Regulation Act—the electric bill of the Company's typical residential customer in Virginia was $107.20. Using 2008 as the baseline, the projected compound annual growth rate for the typical residential customer bill through 2035 is approximately 1.7% using the Company Methodology.

Figure 2.5.1 – Residential Bill Projection (1,000 kWh per Month)

	Plan B – Company Methodology[1]			**Plan B – Directed Methodology**		
	Projected Bill	CAGR Dec 2019	CAGR May 2020	Projected Bill	CAGR Dec 2019	CAGR May 2020
Dec 31, 2019	$122.66			$122.66		
May 1, 2020	$116.18			$116.18		
May 1, 2021	$117.47			$117.47		
Year End 2030	$163.13	2.6%	3.2%	$177.89	3.4%	4.1%
Year End 2035	$171.05	2.1%	2.5%	$199.35	3.1%	3.5%
Total Bill Increase (May 2020-2035)	$54.87			$83.17		

Note: (1) Derived using the system resources selected in Alternative Plan B incorporating the Company Methodology for the purposes of the billing analysis, including forecasted sales growth, forecasted class allocation factors, and a 25.4% capacity factor for solar resources.

For perspective, the average bill for residential customers in states participating in RGGI, normalized for 1,000 kWh monthly usage, is approximately $179.41 based on federal data. The Company's typical residential bill as of May 1, 2021 (*i.e.*, $117.47) compares favorably to this benchmark, as shown in Figure 2.5.2.

Figure 2.5.2 – Residential Bill Comparison for RGGI States[1]

Note: (1) Based on residential rate data for RGGI states from U.S. Energy Information Administration as of June 2021, normalized for 1,000 kilowatt-hour monthly usage. Typical 1,000 kilowatt-hour residential bill for Company uses rates in effect May 1, 2021.

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Extraordinarily Sensitive Information Redacted

Rate Outlook 2020 to 2035

RESIDENTIAL BILL PROJECTION - PLAN A, COMPANY METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	[redacted]													
FUEL (MARKET FORECAST)	$ 23.25	$ 17.36	$ 17.02	$ 20.45														
DSM (APPROVED & PROPOSED)	$ 1.13	$ 1.13	$ 1.47	$ 1.37														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.03														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	$ 12.91	$ 12.76	$ 12.87	$ 13.42	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]													
STRATEGIC UNDERGROUND PLAN	$ 1.84	$ 1.40	$ 1.40	$ 2.14														
RURAL BROADBAND	$ -	$ -	$ -	$ 0.03														
A5 Environmental																		
RIDER E	$ 1.99	$ 1.99	$ 1.67	$ 1.25	[redacted]													
RIDER RGGI	$ -	$ -	$ -	$ 2.39														
RIDER CCR	$ -	$ -	$ -	$ 2.95														
Additional Resources in Plan A																		
GAS CT (2026 & 2027)	$ -	$ -	$ -	$ -	[redacted]													
BIOMASS - 2023 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.81	$ 0.70	$ (0.56)	$ (0.68)	$ (0.70)	$ (0.71)	$ (0.91)	$ (0.10)	$ -	$ -	$ -	$ -	$ -	$ -
VCHEC - 2023 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.51	$ 12.21	$ (3.36)	$ (3.20)	$ (3.13)	$ (3.05)	$ (2.95)	$ (2.85)	$ (2.78)	$ (2.72)	$ (2.58)	$ (2.53)	$ (2.47)	$ (2.58)
RPS Program-Related Resources Plan A																		
RIDER RPS [4]	$ -	$ -	$ -	$ 0.18	$ 0.49	$ 1.23	$ 1.39	$ 1.92	$ 1.90	$ 1.90	$ 1.80	$ 1.59	$ 1.28	$ 0.93	$ 1.04	$ 1.17	$ 1.34	$ 1.51
RIDER CE [5]	$ -	$ -	$ -	$ 0.19	$ 0.22	$ 0.29	$ 0.27	$ 0.26	$ 0.24	$ 0.23	$ 0.22	$ 0.21	$ 0.20	$ 0.19	$ 0.18	$ 0.18	$ 0.17	$ 0.16
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.04)	$ (0.07)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.06)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.05)	$ (0.04)	$ (0.02)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ (0.01)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.03)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 0.18**	**$ 0.21**	**$ 0.19**	**$ 0.18**	**$ 0.11**	**$ 0.11**	**$ 0.12**	**$ 0.12**	**$ 0.11**	**$ 0.11**	**$ 0.09**	**$ 0.08**	**$ 0.08**	**$ 0.07**
RIDER PPA [5]	$ -	$ -	$ -	$ -	$ 0.27	$ 0.37	$ 0.60	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.62
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.54)	$ (0.52)	$ (0.51)	$ (0.50)	$ (0.51)	$ (0.52)	$ (0.52)	$ (0.52)	$ (0.54)	$ (0.55)	$ (0.56)	$ (0.56)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.53)	$ (0.28)	$ (0.16)	$ (0.13)	$ (0.09)	$ (0.06)	$ (0.06)	$ (0.06)	$ (0.07)	$ (0.07)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.08)	$ (0.08)	$ (0.08)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.27**	**$ 0.37**	**$ (0.01)**	**$ 0.01**	**$ (0.51)**	**$ (0.25)**	**$ (0.14)**	**$ (0.12)**	**$ (0.08)**	**$ (0.06)**	**$ (0.08)**	**$ (0.09)**	**$ (0.10)**	**$ (0.11)**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	$ -	$ -	$ -	$ 0.37	$ 0.94	$ 1.81	$ 1.56	$ 2.11	$ 1.50	$ 1.76	$ 1.78	$ 1.58	$ 1.31	$ 0.97	$ 1.05	$ 1.16	$ 1.32	$ 1.47
PLAN A TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.55**	**$ 122.80**	**$ 128.79**	**$ 140.02**	**$ 123.30**	**$ 124.13**	**$ 126.03**	**$ 127.35**	**$ 129.87**	**$ 129.06**	**$ 129.05**	**$ 129.16**	**$ 128.93**	**$ 130.05**	**$ 129.77**	**$ 129.49**
CAGR PLAN A (2019 BASE)													0.5%					0.3%
CAGR PLAN A (MAY 2020 BASE)													1.0%					0.7%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Rider PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Solar only.

Extraordinarily Sensitive Information Redacted

Rate Outlook 2020 to 2035

RESIDENTIAL BILL PROJECTION - PLAN B, COMPANY METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	61.82	61.82	61.82	61.82	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54
TRANSMISSION - RIDER T	19.72	19.72	20.29	16.60	[redacted]													
FUEL (MARKET FORECAST)	23.25	17.36	17.02	20.45														
DSM (APPROVED & PROPOSED)	1.13	1.13	1.47	1.37														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.03														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	12.91	12.76	12.87	13.39	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	-	-	-	-	[redacted]													
STRATEGIC UNDERGROUND PLAN	1.84	1.40	1.40	2.14														
RURAL BROADBAND	-	-	-	0.03														
A5 Environmental																		
RIDER E	1.99	1.99	1.67	1.25	[redacted]													
RIDER RGGI	-	-	-	2.39														
RIDER CCR	-	-	-	2.95														
Additional Resources in Plan B																		
INCREMENTAL GENERIC DSM	-	-	-	-	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	-	-	-	-														
VCHEC 2045 RETIREMENT	-	-	-	-	0.08	0.26	0.23	0.22	0.22	0.20	0.19	0.18	0.17	0.16	0.14	0.13	0.12	0.11
RPS Program-Related Resources Plan B																		
RIDER RPS [4]	-	-	-	0.18	0.49	1.23	1.39	1.92	1.90	1.90	1.80	1.59	1.28	0.93	1.04	1.17	1.34	1.51
RIDER CE [5]	-	-	-	0.19	2.19	3.62	5.38	8.10	10.00	11.99	14.02	15.89	17.62	19.42	21.12	22.83	24.29	25.26
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.08)	(0.18)	(0.74)	(1.36)	(1.97)	(2.55)	(3.23)	(3.93)	(4.56)	(5.25)	(6.08)	(6.88)	(7.65)	(8.37)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(0.30)	(0.82)	(0.62)	(0.58)	(0.50)	(0.37)	(0.38)	(0.39)	(0.45)	(0.50)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.02)	(0.08)	(0.28)	(0.52)	(0.78)	(1.04)	(1.31)	(1.61)	(1.91)	(2.24)	(2.58)	(2.93)	(3.30)	(3.68)
TOTAL RIDER CE	**-**	**-**	**-**	**0.19**	**2.09**	**3.36**	**4.36**	**6.23**	**6.95**	**7.59**	**8.86**	**9.77**	**10.65**	**11.56**	**12.09**	**12.63**	**12.89**	**12.71**
RIDER PPA [6]	-	-	-	-	0.32	0.44	0.78	1.13	1.61	2.02	2.43	2.89	3.20	3.68	4.19	4.68	5.05	5.56
RIDER PPA - FUEL BENEFIT	-	-	-	-	(0.01)	(0.08)	(0.74)	(0.85)	(1.18)	(1.49)	(1.86)	(2.22)	(2.55)	(2.95)	(3.39)	(3.82)	(4.22)	(4.61)
RIDER PPA - REC PROXY	-	-	-	-	-	-	-	-	(0.37)	(0.45)	(0.39)	(0.33)	(0.27)	(0.20)	(0.21)	(0.23)	(0.28)	(0.27)
RIDER PPA - CAPACITY OFFSET	-	-	-	-	-	-	(0.12)	(0.18)	(0.32)	(0.46)	(0.61)	(0.76)	(0.92)	(1.10)	(1.28)	(1.46)	(1.66)	(1.86)
TOTAL RIDER PPA	**-**	**-**	**-**	**-**	**0.31**	**0.36**	**(0.07)**	**0.10**	**(0.26)**	**(0.39)**	**(0.42)**	**(0.42)**	**(0.54)**	**(0.57)**	**(0.68)**	**(0.82)**	**(1.11)**	**(1.17)**
RIDER OSW [2]	-	-	-	-	2.23	2.66	5.99	9.41	11.16	17.34	16.12	17.47	16.87	19.13	21.70	22.45	27.93	26.08
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	-	(0.44)	(3.42)	(3.50)	(3.57)	(3.62)	(3.71)	(3.82)	(4.41)	(8.05)	(8.22)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	-	-	(0.35)	(0.31)	(0.22)	(0.15)	(0.14)	(0.13)	(0.15)	(0.21)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	-	(0.49)	(0.50)	(0.50)	(0.51)	(0.51)	(0.52)	(0.52)	(1.05)	(1.07)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**-**	**-**	**-**	**-**	**2.23**	**2.66**	**5.99**	**9.41**	**10.72**	**13.42**	**11.78**	**13.10**	**12.52**	**14.76**	**17.23**	**17.38**	**18.68**	**16.57**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**0.37**	**5.11**	**7.60**	**11.67**	**17.65**	**19.32**	**22.52**	**22.01**	**24.04**	**23.91**	**26.68**	**29.68**	**30.35**	**31.80**	**29.62**
PLAN B TOTAL	**122.66**	**116.18**	**116.55**	**122.77**	**130.01**	**134.02**	**142.34**	**148.41**	**157.70**	**160.99**	**161.81**	**163.16**	**163.13**	**166.71**	**169.16**	**171.47**	**174.03**	**171.05**
CAGR PLAN B (2019 BASE)													2.6%					2.1%
CAGR PLAN B (MAY 2020 BASE)													3.2%					2.5%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted
Rate Outlook 2020 to 2035

RESIDENTIAL BILL PROJECTION - PLAN C, COMPANY METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	[redacted]													
FUEL (MARKET FORECAST)	$ 23.25	$ 17.36	$ 17.02	$ 20.45														
DSM (APPROVED & PROPOSED)	$ 1.13	$ 1.13	$ 1.47	$ 1.37														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.03														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]													
STRATEGIC UNDERGROUND PLAN	$ 1.84	$ 1.40	$ 1.40	$ 2.14														
RURAL BROADBAND	$ -	$ -	$ -	$ 0.03														
A5 Environmental																		
RIDER E	$ 1.99	$ 1.99	$ 1.67	$ 1.25	[redacted]													
RIDER RGGI	$ -	$ -	$ -	$ 2.39														
RIDER CCR	$ -	$ -	$ -	$ 2.95														
Additional Resources in Plan C																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	$ -	$ -	$ -	$ -														
BEAR GARDEN 2039 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.04	$ 0.14	$ 0.11	$ 0.10	$ 0.12	$ 0.11	$ 0.09	$ 0.12	$ 0.11	$ 0.10	$ 0.09	$ 0.07	$ 0.06	$ 0.17
VCHEC 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.08	$ 0.26	$ 0.23	$ 0.22	$ 0.22	$ 0.20	$ 0.19	$ 0.18	$ 0.17	$ 0.16	$ 0.14	$ 0.13	$ 0.12	$ 0.11
BRUNSWICK 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.09	$ 0.12	$ 0.11	$ 0.11	$ 0.11	$ 0.08	$ 0.08	$ 0.08	$ 0.07	$ 0.07	$ 0.07	$ 0.06	$ 0.07	$ 0.07
GREENSVILLE 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.05	$ 0.19	$ 0.16	$ 0.15	$ 0.14	$ 0.13	$ 0.12	$ 0.12	$ 0.12	$ 0.11	$ 0.10	$ 0.12	$ 0.12	$ 0.11
WARREN 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.07	$ 0.08	$ 0.07	$ 0.08	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.08	$ 0.08	$ 0.09	$ 0.08
RPS Program-Related Resources Plan C																		
RIDER RPS [4]	$ -	$ -	$ -	$ 0.18	$ 0.49	$ 1.23	$ 1.39	$ 1.92	$ 1.90	$ 1.90	$ 1.80	$ 1.59	$ 1.28	$ 0.93	$ 1.04	$ 1.17	$ 1.34	$ 1.51
RIDER CE [5]	$ -	$ -	$ -	$ 0.19	$ 2.19	$ 3.62	$ 5.38	$ 8.10	$ 10.00	$ 11.99	$ 14.02	$ 15.89	$ 17.65	$ 19.55	$ 21.47	$ 23.67	$ 25.52	$ 26.81
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.08)	$ (0.18)	$ (0.74)	$ (1.36)	$ (1.97)	$ (2.55)	$ (3.23)	$ (3.93)	$ (4.56)	$ (5.25)	$ (6.08)	$ (6.88)	$ (7.65)	$ (8.37)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.30)	$ (0.82)	$ (0.62)	$ (0.58)	$ (0.50)	$ (0.37)	$ (0.38)	$ (0.39)	$ (0.45)	$ (0.50)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.02)	$ (0.08)	$ (0.28)	$ (0.52)	$ (0.78)	$ (1.04)	$ (1.31)	$ (1.61)	$ (1.91)	$ (2.24)	$ (2.58)	$ (3.03)	$ (3.48)	$ (3.95)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 2.09**	**$ 3.36**	**$ 4.36**	**$ 6.23**	**$ 6.95**	**$ 7.59**	**$ 8.86**	**$ 9.77**	**$ 10.68**	**$ 11.69**	**$ 12.44**	**$ 13.37**	**$ 13.94**	**$ 14.00**
RIDER PPA [6]	$ -	$ -	$ -	$ -	$ 0.32	$ 0.44	$ 0.78	$ 1.13	$ 1.61	$ 2.02	$ 2.44	$ 2.89	$ 3.21	$ 3.68	$ 4.20	$ 5.04	$ 5.71	$ 6.53
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.01)	$ (0.08)	$ (0.74)	$ (0.85)	$ (1.18)	$ (1.49)	$ (1.86)	$ (2.22)	$ (2.55)	$ (2.95)	$ (3.39)	$ (3.82)	$ (4.22)	$ (4.61)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.37)	$ (0.45)	$ (0.39)	$ (0.33)	$ (0.27)	$ (0.20)	$ (0.21)	$ (0.23)	$ (0.28)	$ (0.27)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.12)	$ (0.18)	$ (0.32)	$ (0.46)	$ (0.61)	$ (0.76)	$ (0.92)	$ (1.10)	$ (1.28)	$ (1.51)	$ (1.75)	$ (2.00)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.31**	**$ 0.36**	**$ (0.07)**	**$ 0.10**	**$ (0.26)**	**$ (0.39)**	**$ (0.42)**	**$ (0.42)**	**$ (0.53)**	**$ (0.56)**	**$ (0.67)**	**$ (0.52)**	**$ (0.54)**	**$ (0.35)**
RIDER OSW [2]	$ -	$ -	$ -	$ -	$ 2.23	$ 2.66	$ 5.99	$ 9.41	$ 11.16	$ 17.34	$ 16.12	$ 17.47	$ 16.87	$ 19.13	$ 21.70	$ 22.45	$ 27.93	$ 26.08
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.44)	$ (3.42)	$ (3.50)	$ (3.57)	$ (3.62)	$ (3.71)	$ (3.82)	$ (4.41)	$ (8.05)	$ (8.22)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.35)	$ (0.31)	$ (0.22)	$ (0.15)	$ (0.14)	$ (0.13)	$ (0.15)	$ (0.21)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.49)	$ (0.50)	$ (0.50)	$ (0.51)	$ (0.51)	$ (0.52)	$ (0.52)	$ (1.05)	$ (1.07)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2.23**	**$ 2.66**	**$ 5.99**	**$ 9.41**	**$ 10.72**	**$ 13.42**	**$ 11.78**	**$ 13.10**	**$ 12.52**	**$ 14.76**	**$ 17.23**	**$ 17.38**	**$ 18.68**	**$ 16.57**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 5.11**	**$ 7.60**	**$ 11.67**	**$ 17.65**	**$ 19.32**	**$ 22.52**	**$ 22.02**	**$ 24.04**	**$ 23.95**	**$ 26.81**	**$ 30.03**	**$ 31.40**	**$ 33.42**	**$ 31.73**
PLAN C TOTAL	**$ 122.66**	**$ 116.18**	**$ 116.55**	**$ 122.77**	**$ 130.39**	**$ 134.61**	**$ 142.84**	**$ 148.91**	**$ 158.23**	**$ 161.44**	**$ 162.23**	**$ 163.62**	**$ 163.57**	**$ 167.25**	**$ 169.90**	**$ 172.91**	**$ 175.98**	**$ 173.55**
CAGR PLAN C (2019 BASE)													2.7%					2.2%
CAGR PLAN C (MAY 2020 BASE)													3.3%					2.6%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted
Rate Outlook 2020 to 2035

SMALL GENERAL SERVICES BILL PROJECTION - PLAN A, COMPANY METHODOLOGY

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Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	276.54	276.54	276.54	276.54	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65
TRANSMISSION - RIDER T	76.59	76.59	89.37	70.55	[redacted]													
FUEL (MARKET FORECAST)	139.52	104.14	102.13	122.69														
DSM (APPROVED & PROPOSED)	5.33	5.33	6.49	6.59														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.16														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	61.54	58.22	57.99	66.03	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	-	-	-	-	[redacted]													
STRATEGIC UNDERGROUND PLAN	8.75	5.90	5.90	9.18														
RURAL BROADBAND	-	-	-	0.12														
A5 Environmental																		
RIDER E	9.44	9.44	7.48	5.99	[redacted]													
RIDER RGGI	-	-	-	14.36														
RIDER CCR	-	-	-	17.67														
Additional Resources in Plan A																		
GAS CT (2026 & 2027)	-	-	-	-	[redacted]													
BIOMASS - 2023 RETIREMENT	-	-	-	-	3.31	2.71	(2.62)	(3.20)	(3.29)	(3.34)	(4.29)	(0.49)	-	-	-	-	-	-
VCHEC - 2023 RETIREMENT	-	-	-	-	2.08	47.37	(15.88)	(15.12)	(14.80)	(14.44)	(13.95)	(13.46)	(13.14)	(12.88)	(12.22)	(11.96)	(11.69)	(12.18)
RPS Program-Related Resources Plan A																		
RIDER RPS [4]	-	-	-	1.09	2.92	7.39	8.33	11.54	11.39	11.38	10.81	9.52	7.69	5.56	6.23	7.02	8.05	9.05
RIDER CE [5]	-	-	-	0.92	0.91	1.39	1.28	1.22	1.15	1.09	1.04	0.99	0.95	0.91	0.87	0.83	0.80	0.77
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.26)	(0.40)	(0.37)	(0.35)	(0.35)	(0.34)	(0.34)	(0.35)	(0.35)	(0.35)	(0.37)	(0.37)	(0.38)	(0.38)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(0.32)	(0.23)	(0.12)	(0.08)	(0.06)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)
RIDER CE - CAPACITY OFFSET	-	-	-	-	-	(0.07)	(0.10)	(0.10)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
TOTAL RIDER CE	**-**	**-**	**-**	**0.92**	**0.65**	**0.92**	**0.81**	**0.76**	**0.38**	**0.41**	**0.47**	**0.45**	**0.43**	**0.41**	**0.35**	**0.31**	**0.27**	**0.23**
RIDER PPA [5]	-	-	-	-	1.36	2.12	3.47	3.52	3.53	3.51	3.50	3.49	3.49	3.49	3.50	3.50	3.52	3.53
RIDER PPA - FUEL BENEFIT	-	-	-	-	-	-	(3.21)	(3.11)	(3.05)	(2.98)	(3.03)	(3.09)	(3.09)	(3.13)	(3.23)	(3.31)	(3.35)	(3.38)
RIDER PPA - REC PROXY	-	-	-	-	-	-	-	-	(3.20)	(1.66)	(0.95)	(0.75)	(0.54)	(0.35)	(0.36)	(0.37)	(0.39)	(0.41)
RIDER PPA - CAPACITY OFFSET	-	-	-	-	-	-	(0.38)	(0.40)	(0.40)	(0.40)	(0.40)	(0.41)	(0.41)	(0.41)	(0.42)	(0.42)	(0.43)	(0.43)
TOTAL RIDER PPA	**-**	**-**	**-**	**-**	**1.36**	**2.12**	**(0.12)**	**0.01**	**(3.13)**	**(1.54)**	**(0.88)**	**(0.76)**	**(0.56)**	**(0.40)**	**(0.51)**	**(0.60)**	**(0.65)**	**(0.68)**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	-	-	-	2.01	4.93	10.43	9.02	12.31	8.65	10.26	10.40	9.21	7.56	5.56	6.07	6.73	7.67	8.59
PLAN A TOTAL	**577.71**	**536.16**	**545.89**	**591.89**	**597.03**	**644.18**	**581.70**	**584.68**	**591.81**	**595.85**	**606.67**	**599.71**	**597.66**	**597.26**	**595.80**	**602.32**	**601.22**	**600.19**
CAGR PLAN A (2019 BASE)													0.3%					0.2%
CAGR PLAN A (MAY 2020 BASE)													1.0%					0.7%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Rider PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Solar only.

Extraordinarily Sensitive Information Redacted

Rate Outlook 2020 to 2035

SMALL GENERAL SERVICES BILL PROJECTION - PLAN B, COMPANY METHODOLOGY

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Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 276.54	$ 276.54	$ 276.54	$ 276.54	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	[redacted]													
FUEL (MARKET FORECAST)	$ 139.52	$ 104.14	$ 102.13	$ 122.69														
DSM (APPROVED & PROPOSED)	$ 5.33	$ 5.33	$ 6.49	$ 6.59														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]													
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18														
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12														
A5 Environmental																		
RIDER E	$ 9.44	$ 9.44	$ 7.48	$ 5.99	[redacted]													
RIDER RGGI	$ -	$ -	$ -	$ 14.36														
RIDER CCR	$ -	$ -	$ -	$ 17.67														
Additional Resources in Plan B																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	$ -	$ -	$ -	$ -														
VCHEC 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.32	$ 1.01	$ 1.07	$ 1.04	$ 1.02	$ 0.94	$ 0.91	$ 0.83	$ 0.79	$ 0.74	$ 0.68	$ 0.62	$ 0.58	$ 0.52
RPS Program-Related Resources Plan B																		
RIDER RPS [4]	$ -	$ -	$ -	$ 1.09	$ 2.92	$ 7.39	$ 8.33	$ 11.54	$ 11.39	$ 11.38	$ 10.81	$ 9.52	$ 7.69	$ 5.56	$ 6.23	$ 7.02	$ 8.05	$ 9.05
RIDER CE [5]	$ -	$ -	$ -	$ 0.92	$ 8.95	$ 17.09	$ 25.39	$ 38.24	$ 47.20	$ 56.60	$ 66.18	$ 74.99	$ 83.17	$ 91.66	$ 99.71	$ 107.77	$ 114.67	$ 119.24
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.46)	$ (1.09)	$ (4.43)	$ (8.14)	$ (11.79)	$ (15.28)	$ (19.39)	$ (23.60)	$ (27.37)	$ (31.52)	$ (36.46)	$ (41.30)	$ (45.90)	$ (50.19)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.82)	$ (4.90)	$ (3.70)	$ (3.45)	$ (2.97)	$ (2.23)	$ (2.26)	$ (2.36)	$ (2.72)	$ (3.01)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.09)	$ (0.37)	$ (1.31)	$ (2.45)	$ (3.67)	$ (4.89)	$ (6.20)	$ (7.58)	$ (9.02)	$ (10.56)	$ (12.17)	$ (13.83)	$ (15.58)	$ (17.38)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 8.40**	**$ 15.63**	**$ 19.64**	**$ 27.65**	**$ 29.92**	**$ 31.53**	**$ 36.90**	**$ 40.37**	**$ 43.80**	**$ 47.34**	**$ 48.81**	**$ 50.28**	**$ 50.47**	**$ 48.66**
RIDER PPA [6]	$ -	$ -	$ -	$ -	$ 1.60	$ 2.51	$ 4.45	$ 6.38	$ 9.08	$ 11.33	$ 13.60	$ 16.15	$ 17.93	$ 20.50	$ 23.30	$ 25.95	$ 27.86	$ 30.54
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.07)	$ (0.48)	$ (4.42)	$ (5.10)	$ (7.09)	$ (8.96)	$ (11.14)	$ (13.32)	$ (15.31)	$ (17.69)	$ (20.32)	$ (22.89)	$ (25.34)	$ (27.65)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.21)	$ (2.70)	$ (2.32)	$ (1.96)	$ (1.60)	$ (1.19)	$ (1.25)	$ (1.38)	$ (1.67)	$ (1.60)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.54)	$ (0.85)	$ (1.51)	$ (2.18)	$ (2.87)	$ (3.59)	$ (4.35)	$ (5.19)	$ (6.01)	$ (6.90)	$ (7.82)	$ (8.77)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.53**	**$ 2.03**	**$ (0.51)**	**$ 0.44**	**$ (1.73)**	**$ (2.51)**	**$ (2.74)**	**$ (2.72)**	**$ (3.33)**	**$ (3.56)**	**$ (4.28)**	**$ (5.22)**	**$ (6.97)**	**$ (7.47)**
RIDER OSW [2]	$ -	$ -	$ -	$ -	$ 9.13	$ 12.55	$ 28.27	$ 44.41	$ 52.65	$ 81.83	$ 76.10	$ 82.48	$ 79.63	$ 90.32	$ 102.43	$ 105.97	$ 131.86	$ 123.09
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.62)	$ (20.53)	$ (21.01)	$ (21.39)	$ (21.74)	$ (22.28)	$ (22.94)	$ (26.48)	$ (48.28)	$ (49.33)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.09)	$ (1.86)	$ (1.34)	$ (0.88)	$ (0.82)	$ (0.79)	$ (0.90)	$ (1.28)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.33)	$ (2.35)	$ (2.37)	$ (2.39)	$ (2.41)	$ (2.43)	$ (2.46)	$ (4.98)	$ (5.04)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9.13**	**$ 12.55**	**$ 28.27**	**$ 44.41**	**$ 50.03**	**$ 58.97**	**$ 50.66**	**$ 56.86**	**$ 54.16**	**$ 64.75**	**$ 76.24**	**$ 76.23**	**$ 77.70**	**$ 67.44**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 21.97**	**$ 37.60**	**$ 55.73**	**$ 84.03**	**$ 89.62**	**$ 99.37**	**$ 95.63**	**$ 104.02**	**$ 102.32**	**$ 114.08**	**$ 127.00**	**$ 128.31**	**$ 129.25**	**$ 117.68**
PLAN B TOTAL	**$ 577.71**	**$ 536.16**	**$ 545.89**	**$ 591.75**	**$ 598.74**	**$ 626.19**	**$ 668.84**	**$ 695.91**	**$ 733.20**	**$ 744.14**	**$ 742.47**	**$ 745.01**	**$ 742.10**	**$ 758.10**	**$ 768.18**	**$ 779.57**	**$ 788.20**	**$ 773.06**
CAGR PLAN B (2019 BASE)													2.3%					1.8%
CAGR PLAN B (MAY 2020 BASE)													3.1%					2.4%

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[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted

Rate Outlook 2020 to 2035

SMALL GENERAL SERVICES BILL PROJECTION - PLAN C, COMPANY METHODOLOGY

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Rate projections assume return on equity of 9.20%.

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DISTRIBUTION & GENERATION (BASE) [1]	276.54	276.54	276.54	276.54	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65
TRANSMISSION - RIDER T	76.59	76.59	89.37	70.55	[redacted]													
FUEL (MARKET FORECAST)	139.52	104.14	102.13	122.69	[redacted]													
DSM (APPROVED & PROPOSED)	5.33	5.33	6.49	6.59	[redacted]													
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.16	[redacted]													
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	61.54	58.22	57.99	65.89	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-	[redacted]													
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	-	-	-	-	[redacted]													
STRATEGIC UNDERGROUND PLAN	8.75	5.90	5.90	9.18	[redacted]													
RURAL BROADBAND	-	-	-	0.12	[redacted]													
A5 Environmental																		
RIDER E	9.44	9.44	7.48	5.99	[redacted]													
RIDER RGGI	-	-	-	14.36	[redacted]													
RIDER CCR	-	-	-	17.67	[redacted]													
Additional Resources in Plan C																		
INCREMENTAL GENERIC DSM	-	-	-	-	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	-	-	-	-	[redacted]													
BEAR GARDEN 2039 RETIREMENT	-	-	-	-	0.16	0.55	0.51	0.47	0.56	0.50	0.44	0.59	0.52	0.46	0.40	0.34	0.29	0.80
VCHEC 2045 RETIREMENT	-	-	-	-	0.32	1.01	1.07	1.04	1.02	0.94	0.91	0.83	0.79	0.74	0.68	0.62	0.58	0.52
BRUNSWICK 2045 RETIREMENT	-	-	-	-	0.40	0.57	0.53	0.54	0.52	0.38	0.39	0.37	0.32	0.34	0.35	0.30	0.34	0.34
GREENSVILLE 2045 RETIREMENT	-	-	-	-	0.19	0.73	0.73	0.68	0.67	0.62	0.58	0.58	0.56	0.53	0.47	0.58	0.56	0.54
WARREN 2045 RETIREMENT	-	-	-	-	0.31	0.29	0.35	0.38	0.35	0.36	0.35	0.31	0.32	0.31	0.36	0.40	0.42	0.38
RPS Program-Related Resources Plan C																		
RIDER RPS [4]	-	-	-	1.09	2.92	7.39	8.33	11.54	11.39	11.38	10.81	9.52	7.69	5.56	6.23	7.02	8.05	9.05
RIDER CE [5]	-	-	-	0.92	8.95	17.09	25.39	38.24	47.20	56.60	66.18	74.99	83.32	92.28	101.33	111.72	120.49	126.55
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.46)	(1.09)	(4.43)	(8.14)	(11.79)	(15.28)	(19.39)	(23.60)	(27.37)	(31.52)	(36.46)	(41.30)	(45.90)	(50.19)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(1.82)	(4.90)	(3.70)	(3.45)	(2.97)	(2.23)	(2.26)	(2.36)	(2.72)	(3.01)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.09)	(0.37)	(1.31)	(2.45)	(3.67)	(4.89)	(6.20)	(7.58)	(9.02)	(10.56)	(12.17)	(14.27)	(16.42)	(18.62)
TOTAL RIDER CE	**-**	**-**	**-**	**0.92**	**8.40**	**15.63**	**19.64**	**27.65**	**29.92**	**31.53**	**36.90**	**40.37**	**43.96**	**47.96**	**50.43**	**53.78**	**55.44**	**54.73**
RIDER PPA [6]	-	-	-	-	1.60	2.51	4.45	6.38	9.08	11.33	13.64	16.15	17.93	20.51	23.32	27.63	30.99	35.14
RIDER PPA - FUEL BENEFIT	-	-	-	-	(0.07)	(0.48)	(4.42)	(5.10)	(7.09)	(8.96)	(11.14)	(13.32)	(15.31)	(17.69)	(20.32)	(22.89)	(25.34)	(27.65)
RIDER PPA - REC PROXY	-	-	-	-	-	-	-	-	(2.21)	(2.70)	(2.32)	(1.96)	(1.60)	(1.19)	(1.25)	(1.38)	(1.67)	(1.60)
RIDER PPA - CAPACITY OFFSET	-	-	-	-	-	-	(0.54)	(0.85)	(1.51)	(2.18)	(2.87)	(3.59)	(4.35)	(5.19)	(6.01)	(7.14)	(8.27)	(9.44)
TOTAL RIDER PPA	**-**	**-**	**-**	**-**	**1.53**	**2.03**	**(0.51)**	**0.44**	**(1.73)**	**(2.51)**	**(2.69)**	**(2.72)**	**(3.32)**	**(3.56)**	**(4.26)**	**(3.78)**	**(4.29)**	**(3.54)**
RIDER OSW [2]	-	-	-	-	9.13	12.55	28.27	44.41	52.65	81.83	76.10	82.48	79.63	90.32	102.43	105.97	131.86	123.09
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	-	(2.62)	(20.53)	(21.01)	(21.39)	(21.74)	(22.28)	(22.94)	(26.48)	(48.28)	(49.33)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	-	-	(2.09)	(1.86)	(1.34)	(0.88)	(0.82)	(0.79)	(0.90)	(1.28)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	-	(2.33)	(2.35)	(2.37)	(2.39)	(2.41)	(2.43)	(2.46)	(4.98)	(5.04)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**-**	**-**	**-**	**-**	**9.13**	**12.55**	**28.27**	**44.41**	**50.03**	**58.97**	**50.66**	**56.86**	**54.16**	**64.75**	**76.24**	**76.23**	**77.70**	**67.44**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**2.01**	**21.97**	**37.60**	**55.73**	**84.03**	**89.62**	**99.37**	**95.67**	**104.02**	**102.48**	**114.71**	**128.64**	**133.25**	**136.90**	**127.67**
PLAN C TOTAL	**577.71**	**536.16**	**545.89**	**591.75**	**600.50**	**628.69**	**671.31**	**698.35**	**735.84**	**746.32**	**744.56**	**747.26**	**744.22**	**760.71**	**771.75**	**786.44**	**797.40**	**784.87**
CAGR PLAN C (2019 BASE)													2.3%					1.9%
CAGR PLAN C (MAY 2020 BASE)													3.1%					2.5%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted
Rate Outlook 2020 to 2035

LARGE GENERAL SERVICES BILL PROJECTION - PLAN A, COMPANY METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

<u>LARGE GENERAL SERVICE</u> Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15
TRANSMISSION - RIDER T	$ 37,760.00	$ 37,760.00	$ 42,270.00	$ 45,260.00	[redacted]													
FUEL (MARKET FORECAST)	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00														
DSM (APPROVED & PROPOSED)	$ 150.00	$ 150.00	$ 6.49	$ 54.00														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00														
<u>Generation Infrastructure</u>																		
EXISTING GENERATION RIDERS [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,650.00														
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -														
<u>Distribution Infrastructure</u>																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -														
STRATEGIC UNDERGROUND PLAN	$ -	$ -	$ -	$ -														
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00														
<u>A5 Environmental</u>																		
RIDER E	$ 5,560.00	$ 5,560.00	$ 7.48	$ 3,140.00														
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00														
RIDER CCR	$ -	$ -	$ -	$ 17,670.00														
<u>Additional Resources in Plan A</u>																		
GAS CT (2026 & 2027)	$ -	$ -	$ -	$ -	[redacted]													
BIOMASS - 2023 RETIREMENT	$ -	$ -	$ -	$ -	$ 2,030.00	$ 1,690.00	$ (1,300.00)	$ (1,590.00)	$ (1,630.00)	$ (1,660.00)	$ (2,120.00)	$ (250.00)	$ -	$ -	$ -	$ -	$ -	$ -
VCHEC - 2023 RETIREMENT	$ -	$ -	$ -	$ -	$ 1,280.00	$ 29,380.00	$ (7,870.00)	$ (7,500.00)	$ (7,340.00)	$ (7,160.00)	$ (6,920.00)	$ (6,670.00)	$ (6,520.00)	$ (6,390.00)	$ (6,060.00)	$ (5,930.00)	$ (5,800.00)	$ (6,040.00)
<u>RPS Program-Related Resources Plan A</u>																		
RIDER RPS [4]	$ -	$ -	$ -	$ 1,092.00	$ 2,916.00	$ 7,386.00	$ 8,328.00	$ 11,538.00	$ 11,394.00	$ 11,382.00	$ 10,806.00	$ 9,516.00	$ 7,686.00	$ 5,556.00	$ 6,228.00	$ 7,020.00	$ 8,052.00	$ 9,048.00
RIDER CE [5]	$ -	$ -	$ -	$ 480.00	$ 560.00	$ 790.00	$ 730.00	$ 690.00	$ 660.00	$ 620.00	$ 590.00	$ 560.00	$ 540.00	$ 520.00	$ 490.00	$ 480.00	$ 460.00	$ 440.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (258.00)	$ (402.00)	$ (366.00)	$ (354.00)	$ (348.00)	$ (336.00)	$ (342.00)	$ (348.00)	$ (348.00)	$ (354.00)	$ (366.00)	$ (372.00)	$ (378.00)	$ (384.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (318.00)	$ (228.00)	$ (120.00)	$ (84.00)	$ (60.00)	$ (36.00)	$ (36.00)	$ (42.00)	$ (42.00)	$ (42.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ (40.00)	$ (60.00)	$ (60.00)	$ (60.00)	$ (60.00)	$ (60.00)	$ (60.00)	$ (60.00)	$ (60.00)	$ (60.00)	$ (60.00)	$ (60.00)	$ (70.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 302.00**	**$ 348.00**	**$ 304.00**	**$ 276.00**	**$ (66.00)**	**$ (4.00)**	**$ 68.00**	**$ 68.00**	**$ 72.00**	**$ 70.00**	**$ 28.00**	**$ 6.00**	**$ (20.00)**	**$ (56.00)**
RIDER PPA [5]	$ -	$ -	$ -	$ -	$ 1,350.00	$ 1,938.00	$ 3,172.00	$ 3,194.00	$ 3,198.00	$ 3,174.00	$ 3,166.00	$ 3,148.00	$ 3,148.00	$ 3,142.00	$ 3,154.00	$ 3,164.00	$ 3,176.00	$ 3,194.00
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,210.00)	$ (3,108.00)	$ (3,054.00)	$ (2,982.00)	$ (3,030.00)	$ (3,090.00)	$ (3,090.00)	$ (3,126.00)	$ (3,228.00)	$ (3,306.00)	$ (3,354.00)	$ (3,378.00)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,204.00)	$ (1,662.00)	$ (948.00)	$ (750.00)	$ (540.00)	$ (348.00)	$ (360.00)	$ (372.00)	$ (390.00)	$ (408.00)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (220.00)	$ (220.00)	$ (230.00)	$ (230.00)	$ (230.00)	$ (230.00)	$ (230.00)	$ (240.00)	$ (240.00)	$ (240.00)	$ (240.00)	$ (250.00)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,350.00**	**$ 1,938.00**	**$ (258.00)**	**$ (134.00)**	**$ (3,290.00)**	**$ (1,700.00)**	**$ (1,042.00)**	**$ (922.00)**	**$ (712.00)**	**$ (572.00)**	**$ (674.00)**	**$ (754.00)**	**$ (808.00)**	**$ (842.00)**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	$ -	$ -	$ -	$ 1,572.00	$ 4,568.00	$ 9,672.00	$ 8,374.00	$ 11,680.00	$ 8,038.00	$ 9,678.00	$ 9,832.00	$ 8,662.00	$ 7,046.00	$ 5,054.00	$ 5,582.00	$ 6,272.00	$ 7,224.00	$ 8,150.00
PLAN A TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 309,356.66**	**$ 370,770.69**	**$ 372,472.15**	**$ 412,806.15**	**$ 369,656.15**	**$ 372,278.15**	**$ 377,862.15**	**$ 380,248.15**	**$ 389,910.15**	**$ 385,774.15**	**$ 385,788.15**	**$ 388,352.15**	**$ 390,728.15**	**$ 399,794.15**	**$ 401,530.15**	**$ 403,720.15**
CAGR PLAN A (2019 BASE)													0.9%					0.9%
CAGR PLAN A (MAY 2020 BASE)													2.0%					1.6%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Rider PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Solar only.

Extraordinarily Sensitive Information Redacted
Rate Outlook 2020 to 2035

LARGE GENERAL SERVICES BILL PROJECTION - PLAN B, COMPANY METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15
TRANSMISSION - RIDER T	$ 37,760.00	$ 37,760.00	$ 42,270.00	$ 45,260.00	[redacted]													
FUEL (MARKET FORECAST)	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00														
DSM (APPROVED & PROPOSED)	$ 150.00	$ 150.00	$ 6.49	$ 54.00														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]													
STRATEGIC UNDERGROUND PLAN	$ -	$ -	$ -	$ -														
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00														
A5 Environmental																		
RIDER E	$ 5,560.00	$ 5,560.00	$ 7.48	$ 3,140.00	[redacted]													
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00														
RIDER CCR	$ -	$ -	$ -	$ 17,670.00														
Additional Resources in Plan B																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	$ -	$ -	$ -	$ -														
VCHEC 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 200.00	$ 630.00	$ 530.00	$ 510.00	$ 510.00	$ 470.00	$ 450.00	$ 410.00	$ 390.00	$ 370.00	$ 340.00	$ 310.00	$ 290.00	$ 260.00
RPS Program-Related Resources Plan B																		
RIDER RPS [4]	$ -	$ -	$ -	$ 1,092.00	$ 2,916.00	$ 7,386.00	$ 8,328.00	$ 11,538.00	$ 11,394.00	$ 11,382.00	$ 10,806.00	$ 9,516.00	$ 7,686.00	$ 5,556.00	$ 6,228.00	$ 7,020.00	$ 8,052.00	$ 9,048.00
RIDER CE [5]	$ -	$ -	$ -	$ 480.00	$ 5,540.00	$ 9,710.00	$ 14,440.00	$ 21,730.00	$ 26,840.00	$ 32,180.00	$ 37,620.00	$ 42,640.00	$ 47,300.00	$ 52,140.00	$ 56,690.00	$ 61,300.00	$ 65,220.00	$ 67,820.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (462.00)	$ (1,092.00)	$ (4,428.00)	$ (8,136.00)	$ (11,790.00)	$ (15,282.00)	$ (19,386.00)	$ (23,598.00)	$ (27,372.00)	$ (31,524.00)	$ (36,462.00)	$ (41,304.00)	$ (45,900.00)	$ (50,190.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,818.00)	$ (4,896.00)	$ (3,696.00)	$ (3,450.00)	$ (2,970.00)	$ (2,232.00)	$ (2,262.00)	$ (2,358.00)	$ (2,724.00)	$ (3,006.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (50.00)	$ (210.00)	$ (750.00)	$ (1,390.00)	$ (2,070.00)	$ (2,780.00)	$ (3,520.00)	$ (4,300.00)	$ (5,130.00)	$ (6,000.00)	$ (6,910.00)	$ (7,850.00)	$ (8,850.00)	$ (9,880.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 5,028.00**	**$ 8,408.00**	**$ 9,262.00**	**$ 12,204.00**	**$ 11,162.00**	**$ 9,222.00**	**$ 11,018.00**	**$ 11,292.00**	**$ 11,828.00**	**$ 12,384.00**	**$ 11,056.00**	**$ 9,788.00**	**$ 7,746.00**	**$ 4,744.00**
RIDER PPA [6]	$ -	$ -	$ -	$ -	$ 1,590.00	$ 2,290.00	$ 3,968.00	$ 5,638.00	$ 7,922.00	$ 9,866.00	$ 11,762.00	$ 13,912.00	$ 15,518.00	$ 17,592.00	$ 19,878.00	$ 22,040.00	$ 23,444.00	$ 25,532.00
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (66.00)	$ (480.00)	$ (4,422.00)	$ (5,100.00)	$ (7,086.00)	$ (8,964.00)	$ (11,136.00)	$ (13,320.00)	$ (15,306.00)	$ (17,688.00)	$ (20,316.00)	$ (22,890.00)	$ (25,338.00)	$ (27,648.00)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,214.00)	$ (2,700.00)	$ (2,322.00)	$ (1,962.00)	$ (1,602.00)	$ (1,188.00)	$ (1,248.00)	$ (1,380.00)	$ (1,668.00)	$ (1,596.00)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (310.00)	$ (480.00)	$ (850.00)	$ (1,240.00)	$ (1,630.00)	$ (2,040.00)	$ (2,470.00)	$ (2,950.00)	$ (3,420.00)	$ (3,920.00)	$ (4,450.00)	$ (4,990.00)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,524.00**	**$ 1,810.00**	**$ (764.00)**	**$ 58.00**	**$ (2,228.00)**	**$ (3,038.00)**	**$ (3,326.00)**	**$ (3,410.00)**	**$ (3,860.00)**	**$ (4,234.00)**	**$ (5,106.00)**	**$ (6,150.00)**	**$ (8,012.00)**	**$ (8,702.00)**
RIDER OSW [2]	$ -	$ -	$ -	$ -	$ 5,650.00	$ 7,140.00	$ 16,070.00	$ 25,250.00	$ 29,940.00	$ 46,530.00	$ 43,260.00	$ 46,900.00	$ 45,290.00	$ 51,360.00	$ 58,240.00	$ 60,270.00	$ 74,990.00	$ 70,000.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,622.00)	$ (20,526.00)	$ (21,006.00)	$ (21,390.00)	$ (21,738.00)	$ (22,278.00)	$ (22,938.00)	$ (26,484.00)	$ (48,276.00)	$ (49,332.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,088.00)	$ (1,860.00)	$ (1,344.00)	$ (882.00)	$ (816.00)	$ (792.00)	$ (900.00)	$ (1,278.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,330.00)	$ (1,340.00)	$ (1,350.00)	$ (1,360.00)	$ (1,370.00)	$ (1,380.00)	$ (1,400.00)	$ (2,840.00)	$ (2,860.00)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,650.00**	**$ 7,140.00**	**$ 16,070.00**	**$ 25,250.00**	**$ 27,318.00**	**$ 24,674.00**	**$ 18,826.00**	**$ 22,300.00**	**$ 20,848.00**	**$ 26,830.00**	**$ 33,106.00**	**$ 31,594.00**	**$ 22,974.00**	**$ 16,530.00**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 15,118.00**	**$ 24,744.00**	**$ 32,896.00**	**$ 49,050.00**	**$ 47,646.00**	**$ 42,240.00**	**$ 37,324.00**	**$ 39,698.00**	**$ 36,502.00**	**$ 40,536.00**	**$ 45,284.00**	**$ 42,252.00**	**$ 30,760.00**	**$ 21,620.00**
PLAN B TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 309,356.66**	**$ 370,690.69**	**$ 369,640.15**	**$ 398,962.15**	**$ 411,458.15**	**$ 425,796.15**	**$ 442,012.15**	**$ 443,780.15**	**$ 439,236.15**	**$ 440,774.15**	**$ 439,850.15**	**$ 452,390.15**	**$ 459,450.15**	**$ 469,878.15**	**$ 469,768.15**	**$ 461,004.15**
CAGR PLAN B (2019 BASE)													2.1%					1.7%
CAGR PLAN B (MAY 2020 BASE)													3.2%					2.5%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted
Rate Outlook 2020 to 2035

LARGE GENERAL SERVICES BILL PROJECTION - PLAN C, COMPANY METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15
TRANSMISSION - RIDER T	$ 37,760.00	$ 37,760.00	$ 42,270.00	$ 45,260.00	[redacted]					
FUEL (MARKET FORECAST)	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00						
DSM (APPROVED & PROPOSED)	$ 150.00	$ 150.00	$ 6.49	$ 54.00						
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00						
Generation Infrastructure										
EXISTING GENERATION RIDERS [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	[redacted]					
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -						
Distribution Infrastructure										
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]					
STRATEGIC UNDERGROUND PLAN	$ -	$ -	$ -	$ -						
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00						
A5 Environmental										
RIDER E	$ 5,560.00	$ 5,560.00	$ 7.48	$ 3,140.00	[redacted]					
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00						
RIDER CCR	$ -	$ -	$ -	$ 17,670.00						
Additional Resources in Plan C										
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	[redacted]					
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	$ -	$ -	$ -	$ -						
BEAR GARDEN 2039 RETIREMENT	$ -	$ -	$ -	$ -	$ 100.00	$ 340.00	$ 250.00	$ 240.00	$ 280.00	$ 250.00
VCHEC 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 200.00	$ 630.00	$ 530.00	$ 510.00	$ 510.00	$ 470.00
BRUNSWICK 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 230.00	$ 290.00	$ 270.00	$ 280.00	$ 280.00	$ 210.00
GREENSVILLE 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 120.00	$ 450.00	$ 360.00	$ 340.00	$ 330.00	$ 310.00
WARREN 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 190.00	$ 180.00	$ 170.00	$ 190.00	$ 170.00	$ 180.00
RPS Program-Related Resources Plan C										
RIDER RPS [4]	$ -	$ -	$ -	$ 1,092.00	$ 2,916.00	$ 7,386.00	$ 8,328.00	$ 11,538.00	$ 11,394.00	$ 11,382.00
RIDER CE [5]	$ -	$ -	$ -	$ 480.00	$ 5,540.00	$ 9,710.00	$ 14,440.00	$ 21,730.00	$ 26,840.00	$ 32,180.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (462.00)	$ (1,092.00)	$ (4,428.00)	$ (8,136.00)	$ (11,790.00)	$ (15,282.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,818.00)	$ (4,896.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (50.00)	$ (210.00)	$ (750.00)	$ (1,390.00)	$ (2,070.00)	$ (2,780.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 5,028.00**	**$ 8,408.00**	**$ 9,262.00**	**$ 12,204.00**	**$ 11,162.00**	**$ 9,222.00**
RIDER PPA [6]	$ -	$ -	$ -	$ -	$ 1,590.00	$ 2,290.00	$ 3,968.00	$ 5,638.00	$ 7,922.00	$ 9,872.00
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (66.00)	$ (480.00)	$ (4,422.00)	$ (5,100.00)	$ (7,086.00)	$ (8,964.00)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,214.00)	$ (2,700.00)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (310.00)	$ (480.00)	$ (850.00)	$ (1,240.00)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,524.00**	**$ 1,810.00**	**$ (764.00)**	**$ 58.00**	**$ (2,228.00)**	**$ (3,032.00)**
RIDER OSW [2]	$ -	$ -	$ -	$ -	$ 5,650.00	$ 7,140.00	$ 16,070.00	$ 25,250.00	$ 29,940.00	$ 46,530.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,622.00)	$ (20,526.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,330.00)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,650.00**	**$ 7,140.00**	**$ 16,070.00**	**$ 25,250.00**	**$ 27,318.00**	**$ 24,674.00**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 15,118.00**	**$ 24,744.00**	**$ 32,896.00**	**$ 49,050.00**	**$ 47,646.00**	**$ 42,246.00**
PLAN C TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 309,356.66**	**$ 370,690.69**	**$ 370,832.15**	**$ 400,582.15**	**$ 412,862.15**	**$ 427,212.15**	**$ 443,612.15**	**$ 445,060.15**
CAGR PLAN C (2019 BASE)										
CAGR PLAN C (MAY 2020 BASE)										

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15
TRANSMISSION - RIDER T	[redacted]							
FUEL (MARKET FORECAST)								
DSM (APPROVED & PROPOSED)								
RIDER PIPP - UNIVERSAL SERVICE FEE [2]								
Generation Infrastructure								
EXISTING GENERATION RIDERS [3]	[redacted]							
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL								
Distribution Infrastructure								
GT PLAN (APPROVED PHASE 1)	[redacted]							
STRATEGIC UNDERGROUND PLAN								
RURAL BROADBAND								
A5 Environmental								
RIDER E	[redacted]							
RIDER RGGI								
RIDER CCR								
Additional Resources in Plan C								
INCREMENTAL GENERIC DSM	[redacted]							
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)								
BEAR GARDEN 2039 RETIREMENT	$ 220.00	$ 290.00	$ 260.00	$ 230.00	$ 200.00	$ 170.00	$ 140.00	$ 400.00
VCHEC 2045 RETIREMENT	$ 450.00	$ 410.00	$ 390.00	$ 370.00	$ 340.00	$ 310.00	$ 290.00	$ 260.00
BRUNSWICK 2045 RETIREMENT	$ 220.00	$ 220.00	$ 200.00	$ 220.00	$ 230.00	$ 200.00	$ 230.00	$ 240.00
GREENSVILLE 2045 RETIREMENT	$ 290.00	$ 290.00	$ 280.00	$ 260.00	$ 230.00	$ 290.00	$ 280.00	$ 270.00
WARREN 2045 RETIREMENT	$ 170.00	$ 150.00	$ 160.00	$ 150.00	$ 180.00	$ 200.00	$ 210.00	$ 190.00
RPS Program-Related Resources Plan C								
RIDER RPS [4]	$ 10,806.00	$ 9,516.00	$ 7,686.00	$ 5,556.00	$ 6,228.00	$ 7,020.00	$ 8,052.00	$ 9,048.00
RIDER CE [5]	$ 37,620.00	$ 42,640.00	$ 47,390.00	$ 52,500.00	$ 57,610.00	$ 63,540.00	$ 68,520.00	$ 71,980.00
RIDER CE - FUEL BENEFIT	$ (19,386.00)	$ (23,598.00)	$ (27,372.00)	$ (31,524.00)	$ (36,462.00)	$ (41,304.00)	$ (45,900.00)	$ (50,190.00)
RIDER CE - REC PROXY VALUE	$ (3,696.00)	$ (3,450.00)	$ (2,970.00)	$ (2,232.00)	$ (2,262.00)	$ (2,358.00)	$ (2,724.00)	$ (3,006.00)
RIDER CE - CAPACITY OFFSET	$ (3,520.00)	$ (4,300.00)	$ (5,130.00)	$ (6,000.00)	$ (6,910.00)	$ (8,100.00)	$ (9,320.00)	$ (10,590.00)
TOTAL RIDER CE	**$ 11,018.00**	**$ 11,292.00**	**$ 11,918.00**	**$ 12,744.00**	**$ 11,976.00**	**$ 11,778.00**	**$ 10,576.00**	**$ 8,194.00**
RIDER PPA [6]	$ 11,802.00	$ 13,912.00	$ 15,518.00	$ 17,604.00	$ 19,900.00	$ 23,004.00	$ 25,264.00	$ 28,208.00
RIDER PPA - FUEL BENEFIT	$ (11,136.00)	$ (13,320.00)	$ (15,306.00)	$ (17,688.00)	$ (20,316.00)	$ (22,890.00)	$ (25,338.00)	$ (27,648.00)
RIDER PPA - REC PROXY	$ (2,322.00)	$ (1,962.00)	$ (1,602.00)	$ (1,188.00)	$ (1,248.00)	$ (1,380.00)	$ (1,668.00)	$ (1,596.00)
RIDER PPA - CAPACITY OFFSET	$ (1,630.00)	$ (2,040.00)	$ (2,470.00)	$ (2,950.00)	$ (3,420.00)	$ (4,060.00)	$ (4,700.00)	$ (5,370.00)
TOTAL RIDER PPA	**$ (3,286.00)**	**$ (3,410.00)**	**$ (3,860.00)**	**$ (4,222.00)**	**$ (5,084.00)**	**$ (5,326.00)**	**$ (6,442.00)**	**$ (6,406.00)**
RIDER OSW [2]	$ 43,260.00	$ 46,900.00	$ 45,290.00	$ 51,360.00	$ 58,240.00	$ 60,270.00	$ 74,990.00	$ 70,000.00
RIDER OSW - FUEL BENEFIT	$ (21,006.00)	$ (21,390.00)	$ (21,738.00)	$ (22,278.00)	$ (22,938.00)	$ (26,484.00)	$ (48,276.00)	$ (49,332.00)
RIDER OSW - REC PROXY VALUE	$ (2,088.00)	$ (1,860.00)	$ (1,344.00)	$ (882.00)	$ (816.00)	$ (792.00)	$ (900.00)	$ (1,278.00)
RIDER OSW - CAPACITY OFFSET	$ (1,340.00)	$ (1,350.00)	$ (1,360.00)	$ (1,370.00)	$ (1,380.00)	$ (1,400.00)	$ (2,840.00)	$ (2,860.00)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ 18,826.00**	**$ 22,300.00**	**$ 20,848.00**	**$ 26,830.00**	**$ 33,106.00**	**$ 31,594.00**	**$ 22,974.00**	**$ 16,530.00**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ 37,364.00**	**$ 39,698.00**	**$ 36,592.00**	**$ 40,908.00**	**$ 46,226.00**	**$ 45,066.00**	**$ 35,160.00**	**$ 27,366.00**
PLAN C TOTAL	**$ 440,458.15**	**$ 442,132.15**	**$ 441,074.15**	**$ 453,958.15**	**$ 461,574.15**	**$ 473,852.15**	**$ 474,968.15**	**$ 467,604.15**
CAGR PLAN C (2019 BASE)			2.1%					1.8%
CAGR PLAN C (MAY 2020 BASE)			3.3%					2.6%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted
Rate Outlook 2020 to 2035

RESIDENTIAL BILL PROJECTION - PLAN A, DIRECTED METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	61.82	61.82	61.82	61.82	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54
TRANSMISSION - RIDER T	19.72	19.72	20.29	16.60	[redacted]													
FUEL (MARKET FORECAST)	23.25	17.36	17.02	20.45														
DSM (APPROVED & PROPOSED)	1.13	1.13	6.49	1.37														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.03														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	12.91	12.76	12.87	13.42	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	-	-	-	-	[redacted]													
STRATEGIC UNDERGROUND PLAN	1.84	1.40	1.40	2.14														
RURAL BROADBAND	-	-	-	0.03														
A5 Environmental																		
RIDER E	1.99	1.99	7.48	1.25	[redacted]													
RIDER RGGI	-	-	-	2.39														
RIDER CCR	-	-	-	2.95														
Additional Resources in Plan A																		
GAS CT (2026 & 2027)	-	-	-	-	[redacted]													
BIOMASS - 2023 RETIREMENT	-	-	-	-	0.81	0.70	(0.59)	(0.72)	(0.76)	(0.78)	(1.03)	(0.12)	-	-	-	-	-	-
VCHEC - 2023 RETIREMENT	-	-	-	-	0.51	12.21	(3.56)	(3.41)	(3.40)	(3.39)	(3.36)	(3.31)	(3.30)	(3.31)	(3.21)	(3.19)	(3.17)	(3.36)
RPS Program-Related Resources Plan A																		
RIDER RPS [4]	-	-	-	0.18	0.49	1.24	1.41	1.96	1.97	2.02	1.96	1.77	1.46	1.07	1.23	1.40	1.64	1.86
RIDER CE [5]	-	-	-	0.19	0.22	0.31	0.29	0.28	0.26	0.26	0.25	0.24	0.24	0.23	0.23	0.22	0.22	0.21
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.04)	(0.07)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.07)	(0.07)	(0.07)	(0.07)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(0.06)	(0.04)	(0.02)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
RIDER CE - CAPACITY OFFSET	-	-	-	-	-	(0.02)	(0.02)	(0.02)	(0.02)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)
TOTAL RIDER CE	**-**	**-**	**-**	**0.19**	**0.18**	**0.23**	**0.20**	**0.19**	**0.13**	**0.13**	**0.14**	**0.14**	**0.14**	**0.14**	**0.12**	**0.12**	**0.11**	**0.10**
RIDER PPA [5]	-	-	-	-	0.27	0.39	0.65	0.66	0.67	0.69	0.70	0.72	0.73	0.75	0.76	0.77	0.79	0.81
RIDER PPA - FUEL BENEFIT	-	-	-	-	-	-	(0.54)	(0.53)	(0.52)	(0.51)	(0.52)	(0.54)	(0.54)	(0.55)	(0.57)	(0.59)	(0.60)	(0.61)
RIDER PPA - REC PROXY	-	-	-	-	-	-	-	-	(0.56)	(0.30)	(0.17)	(0.14)	(0.10)	(0.07)	(0.07)	(0.08)	(0.08)	(0.08)
RIDER PPA - CAPACITY OFFSET	-	-	-	-	-	-	(0.09)	(0.09)	(0.09)	(0.09)	(0.10)	(0.10)	(0.10)	(0.11)	(0.11)	(0.11)	(0.12)	(0.12)
TOTAL RIDER PPA	**-**	**-**	**-**	**-**	**0.27**	**0.39**	**0.02**	**0.04**	**(0.49)**	**(0.21)**	**(0.09)**	**(0.06)**	**(0.01)**	**0.02**	**0.01**	**0.00**	**(0.00)**	**(0.00)**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	-	-	-	0.37	0.94	1.85	1.62	2.19	1.60	1.94	2.01	1.85	1.58	1.23	1.36	1.52	1.74	1.96
PLAN A TOTAL	**122.66**	**116.18**	**127.38**	**122.80**	**129.56**	**141.45**	**125.49**	**126.44**	**129.06**	**131.41**	**135.21**	**135.17**	**136.10**	**137.23**	**138.05**	**140.08**	**140.62**	**141.03**
CAGR PLAN A (2019 BASE)													0.9%					0.9%
CAGR PLAN A (MAY 2020 BASE)													1.5%					1.2%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Rider PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Solar only.

Extraordinarily Sensitive Information Redacted

Rate Outlook 2020 to 2035

RESIDENTIAL BILL PROJECTION - PLAN B, DIRECTED METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 61.82	$ 61.82	$ 61.82	$ 61.82	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54	$ 61.54
TRANSMISSION - RIDER T	$ 19.72	$ 19.72	$ 20.29	$ 16.60	[redacted]													
FUEL (MARKET FORECAST)	$ 23.25	$ 17.36	$ 17.02	$ 20.45														
DSM (APPROVED & PROPOSED)	$ 1.13	$ 1.13	$ 6.49	$ 1.37														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.03														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	$ 12.91	$ 12.76	$ 12.87	$ 13.39	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]													
STRATEGIC UNDERGROUND PLAN	$ 1.84	$ 1.40	$ 1.40	$ 2.14														
RURAL BROADBAND	$ -	$ -	$ -	$ 0.03														
A5 Environmental																		
RIDER E	$ 1.99	$ 1.99	$ 7.48	$ 1.25	[redacted]													
RIDER RGGI	$ -	$ -	$ -	$ 2.39														
RIDER CCR	$ -	$ -	$ -	$ 2.95														
Additional Resources in Plan B																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	$ -	$ -	$ -	$ -														
VCHEC 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.08	$ 0.26	$ 0.24	$ 0.23	$ 0.24	$ 0.22	$ 0.22	$ 0.21	$ 0.20	$ 0.19	$ 0.18	$ 0.17	$ 0.16	$ 0.14
RPS Program-Related Resources Plan B																		
RIDER RPS [4]	$ -	$ -	$ -	$ 0.18	$ 0.49	$ 1.24	$ 1.41	$ 1.96	$ 1.97	$ 2.02	$ 1.96	$ 1.77	$ 1.46	$ 1.07	$ 1.23	$ 1.40	$ 1.64	$ 1.86
RIDER CE [5]	$ -	$ -	$ -	$ 0.19	$ 2.19	$ 3.80	$ 5.69	$ 8.62	$ 10.81	$ 13.25	$ 15.86	$ 18.36	$ 20.77	$ 23.37	$ 25.94	$ 28.50	$ 30.83	$ 32.54
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.07)	$ (0.17)	$ (0.70)	$ (1.21)	$ (1.72)	$ (2.22)	$ (2.82)	$ (3.42)	$ (3.97)	$ (4.59)	$ (5.35)	$ (6.07)	$ (6.79)	$ (7.46)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.30)	$ (0.86)	$ (0.75)	$ (0.66)	$ (0.57)	$ (0.44)	$ (0.52)	$ (0.61)	$ (0.72)	$ (0.81)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.02)	$ (0.08)	$ (0.30)	$ (0.55)	$ (0.84)	$ (1.15)	$ (1.49)	$ (1.85)	$ (2.26)	$ (2.69)	$ (3.17)	$ (3.66)	$ (4.19)	$ (4.74)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.19**	**$ 2.09**	**$ 3.55**	**$ 4.70**	**$ 6.86**	**$ 7.96**	**$ 9.03**	**$ 10.81**	**$ 12.43**	**$ 13.98**	**$ 15.64**	**$ 16.91**	**$ 18.17**	**$ 19.13**	**$ 19.52**
RIDER PPA [6]	$ -	$ -	$ -	$ -	$ 0.32	$ 0.46	$ 0.84	$ 1.21	$ 1.77	$ 2.26	$ 2.79	$ 3.39	$ 3.84	$ 4.49	$ 5.22	$ 5.92	$ 6.48	$ 7.23
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.64)	$ (0.73)	$ (1.01)	$ (1.27)	$ (1.59)	$ (1.91)	$ (2.20)	$ (2.55)	$ (2.96)	$ (3.34)	$ (3.72)	$ (4.08)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.42)	$ (0.50)	$ (0.42)	$ (0.38)	$ (0.32)	$ (0.24)	$ (0.28)	$ (0.33)	$ (0.38)	$ (0.42)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.12)	$ (0.19)	$ (0.34)	$ (0.51)	$ (0.69)	$ (0.88)	$ (1.09)	$ (1.32)	$ (1.57)	$ (1.83)	$ (2.10)	$ (2.39)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.32**	**$ 0.46**	**$ 0.08**	**$ 0.30**	**$ 0.00**	**$ (0.03)**	**$ 0.09**	**$ 0.23**	**$ 0.24**	**$ 0.38**	**$ 0.42**	**$ 0.43**	**$ 0.27**	**$ 0.34**
RIDER OSW [2]	$ -	$ -	$ -	$ -	$ 2.23	$ 2.79	$ 6.34	$ 10.01	$ 12.06	$ 19.16	$ 18.24	$ 20.19	$ 19.89	$ 23.02	$ 26.65	$ 28.02	$ 35.45	$ 33.59
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.44)	$ (3.45)	$ (3.56)	$ (3.63)	$ (3.71)	$ (3.82)	$ (3.98)	$ (4.61)	$ (8.46)	$ (8.69)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.30)	$ (0.32)	$ (0.24)	$ (0.16)	$ (0.16)	$ (0.17)	$ (0.19)	$ (0.25)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.55)	$ (0.56)	$ (0.58)	$ (0.60)	$ (0.62)	$ (0.63)	$ (0.65)	$ (1.34)	$ (1.38)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2.23**	**$ 2.79**	**$ 6.34**	**$ 10.01**	**$ 11.62**	**$ 15.17**	**$ 13.81**	**$ 15.65**	**$ 15.35**	**$ 18.43**	**$ 21.88**	**$ 22.59**	**$ 25.46**	**$ 23.28**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 0.37**	**$ 5.12**	**$ 8.04**	**$ 12.52**	**$ 19.13**	**$ 21.55**	**$ 26.19**	**$ 26.67**	**$ 30.08**	**$ 31.02**	**$ 35.53**	**$ 40.44**	**$ 42.59**	**$ 46.50**	**$ 45.00**
PLAN B TOTAL	**$ 122.66**	**$ 116.18**	**$ 127.38**	**$ 122.77**	**$ 130.79**	**$ 135.78**	**$ 145.42**	**$ 152.09**	**$ 163.05**	**$ 168.91**	**$ 172.16**	**$ 175.76**	**$ 177.89**	**$ 184.47**	**$ 190.02**	**$ 194.86**	**$ 200.85**	**$ 199.35**
CAGR PLAN B (2019 BASE)													3.4%					3.1%
CAGR PLAN B (MAY 2020 BASE)													4.1%					3.5%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted

Rate Outlook 2020 to 2035

RESIDENTIAL BILL PROJECTION - PLAN C, DIRECTED METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

RESIDENTIAL Schedule 1 (1,000 kWh)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	61.82	61.82	61.82	61.82	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54	61.54
TRANSMISSION - RIDER T	19.72	19.72	20.29	16.60	[redacted]													
FUEL (MARKET FORECAST)	23.25	17.36	17.02	20.45														
DSM (APPROVED & PROPOSED)	1.13	1.13	6.49	1.37														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.03														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	12.91	12.76	12.87	13.39	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	-	-	-	-	[redacted]													
STRATEGIC UNDERGROUND PLAN	1.84	1.40	1.40	2.14														
RURAL BROADBAND	-	-	-	0.03														
A5 Environmental																		
RIDER E	1.99	1.99	7.48	1.25	[redacted]													
RIDER RGGI	-	-	-	2.39														
RIDER CCR	-	-	-	2.95														
Additional Resources in Plan C																		
INCREMENTAL GENERIC DSM	-	-	-	-	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	-	-	-	-														
BEAR GARDEN 2039 RETIREMENT	-	-	-	-	0.04	0.14	0.11	0.11	0.13	0.12	0.11	0.14	0.13	0.12	0.11	0.09	0.08	0.22
VCHEC 2045 RETIREMENT	-	-	-	-	0.08	0.26	0.24	0.23	0.24	0.22	0.22	0.21	0.20	0.19	0.18	0.17	0.16	0.14
BRUNSWICK 2045 RETIREMENT	-	-	-	-	0.09	0.13	0.12	0.12	0.12	0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.09	0.10
GREENSVILLE 2045 RETIREMENT	-	-	-	-	0.05	0.19	0.16	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.12	0.16	0.15	0.15
WARREN 2045 RETIREMENT	-	-	-	-	0.08	0.08	0.08	0.09	0.08	0.09	0.08	0.08	0.08	0.08	0.10	0.11	0.11	0.11
RPS Program-Related Resources Plan C																		
RIDER RPS [4]	-	-	-	0.18	0.49	1.24	1.41	1.96	1.97	2.02	1.96	1.77	1.46	1.07	1.23	1.40	1.64	1.86
RIDER CE [5]	-	-	-	0.19	2.19	3.80	5.69	8.62	10.81	13.25	15.86	18.36	20.81	23.53	26.37	29.55	32.39	34.54
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.07)	(0.17)	(0.70)	(1.21)	(1.72)	(2.22)	(2.82)	(3.42)	(3.97)	(4.59)	(5.35)	(6.07)	(6.79)	(7.46)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(0.30)	(0.86)	(0.75)	(0.66)	(0.57)	(0.44)	(0.52)	(0.61)	(0.72)	(0.81)
RIDER CE - CAPACITY OFFSET	-	-	-	-	(0.02)	(0.08)	(0.30)	(0.55)	(0.84)	(1.15)	(1.49)	(1.85)	(2.26)	(2.69)	(3.17)	(3.78)	(4.42)	(5.08)
TOTAL RIDER CE	**-**	**-**	**-**	**0.19**	**2.09**	**3.55**	**4.70**	**6.86**	**7.96**	**9.03**	**10.81**	**12.43**	**14.02**	**15.80**	**17.33**	**19.09**	**20.47**	**21.18**
RIDER PPA [6]	-	-	-	-	0.32	0.46	0.84	1.21	1.77	2.26	2.80	3.39	3.84	4.49	5.23	6.36	7.32	8.48
RIDER PPA - FUEL BENEFIT	-	-	-	-	-	-	(0.64)	(0.73)	(1.01)	(1.27)	(1.59)	(1.91)	(2.20)	(2.55)	(2.96)	(3.34)	(3.72)	(4.08)
RIDER PPA - REC PROXY	-	-	-	-	-	-	-	-	(0.42)	(0.50)	(0.42)	(0.38)	(0.32)	(0.24)	(0.28)	(0.33)	(0.38)	(0.42)
RIDER PPA - CAPACITY OFFSET	-	-	-	-	-	-	(0.12)	(0.19)	(0.34)	(0.51)	(0.69)	(0.88)	(1.09)	(1.32)	(1.57)	(1.89)	(2.23)	(2.58)
TOTAL RIDER PPA	**-**	**-**	**-**	**-**	**0.32**	**0.46**	**0.08**	**0.30**	**0.00**	**(0.03)**	**0.10**	**0.23**	**0.24**	**0.38**	**0.42**	**0.80**	**0.99**	**1.40**
RIDER OSW [2]	-	-	-	-	2.23	2.79	6.34	10.01	12.06	19.16	18.24	20.19	19.89	23.02	26.65	28.02	35.45	33.59
RIDER OSW - FUEL BENEFIT	-	-	-	-	-	-	-	-	(0.44)	(3.45)	(3.56)	(3.63)	(3.71)	(3.82)	(3.98)	(4.61)	(8.46)	(8.69)
RIDER OSW - REC PROXY VALUE	-	-	-	-	-	-	-	-	-	-	(0.30)	(0.32)	(0.24)	(0.16)	(0.16)	(0.17)	(0.19)	(0.25)
RIDER OSW - CAPACITY OFFSET	-	-	-	-	-	-	-	-	-	(0.55)	(0.56)	(0.58)	(0.60)	(0.62)	(0.63)	(0.65)	(1.34)	(1.38)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**-**	**-**	**-**	**-**	**2.23**	**2.79**	**6.34**	**10.01**	**11.62**	**15.17**	**13.81**	**15.65**	**15.35**	**18.43**	**21.88**	**22.59**	**25.46**	**23.28**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**-**	**-**	**-**	**0.37**	**5.12**	**8.04**	**12.52**	**19.13**	**21.55**	**26.19**	**26.68**	**30.08**	**31.06**	**35.69**	**40.87**	**43.89**	**48.55**	**47.72**
PLAN C TOTAL	**122.66**	**116.18**	**127.38**	**122.77**	**131.17**	**136.37**	**145.95**	**152.62**	**163.62**	**169.40**	**172.64**	**176.28**	**178.40**	**185.10**	**190.92**	**196.64**	**203.32**	**202.60**
CAGR PLAN C (2019 BASE)													3.5%					3.2%
CAGR PLAN C (MAY 2020 BASE)													4.1%					3.6%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted

Rate Outlook 2020 to 2035

SMALL GENERAL SERVICES BILL PROJECTION - PLAN A, DIRECTED METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	276.54	276.54	276.54	276.54	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65	272.65
TRANSMISSION - RIDER T	76.59	76.59	89.37	70.55	[redacted]													
FUEL (MARKET FORECAST)	139.52	104.14	102.13	122.69														
DSM (APPROVED & PROPOSED)	5.33	5.33	6.49	6.59														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	0.16														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	61.54	58.22	57.99	66.03	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	-	-	-	-	[redacted]													
STRATEGIC UNDERGROUND PLAN	8.75	5.90	5.90	9.18														
RURAL BROADBAND	-	-	-	0.12														
A5 Environmental																		
RIDER E	9.44	9.44	7.48	5.99	[redacted]													
RIDER RGGI	-	-	-	14.36														
RIDER CCR	-	-	-	17.67														
Additional Resources in Plan A																		
GAS CT (2026 & 2027)	-	-	-	-	[redacted]													
BIOMASS - 2023 RETIREMENT	-	-	-	-	3.31	2.71	(2.39)	(2.93)	(3.06)	(3.18)	(4.18)	(0.49)	-	-	-	-	-	-
VCHEC - 2023 RETIREMENT	-	-	-	-	2.08	47.37	(14.42)	(13.82)	(13.76)	(13.74)	(13.60)	(13.42)	(13.38)	(13.40)	(13.00)	(12.94)	(12.85)	(13.61)
RPS Program-Related Resources Plan A																		
RIDER RPS [4]	-	-	-	1.09	2.92	7.41	8.44	11.77	11.83	12.11	11.77	10.60	8.74	6.44	7.37	8.42	9.81	11.16
RIDER CE [5]	-	-	-	0.92	0.91	1.27	1.18	1.13	1.09	1.04	1.02	1.00	0.97	0.95	0.93	0.91	0.88	0.86
RIDER CE - FUEL BENEFIT	-	-	-	-	(0.26)	(0.40)	(0.37)	(0.36)	(0.35)	(0.35)	(0.35)	(0.37)	(0.37)	(0.37)	(0.39)	(0.40)	(0.41)	(0.41)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(0.33)	(0.24)	(0.13)	(0.09)	(0.07)	(0.04)	(0.05)	(0.05)	(0.05)	(0.05)
RIDER CE - CAPACITY OFFSET	-	-	-	-	-	(0.06)	(0.10)	(0.10)	(0.10)	(0.10)	(0.11)	(0.11)	(0.11)	(0.11)	(0.12)	(0.12)	(0.13)	(0.13)
TOTAL RIDER CE	**-**	**-**	**-**	**0.92**	**0.65**	**0.80**	**0.71**	**0.67**	**0.30**	**0.35**	**0.43**	**0.43**	**0.43**	**0.42**	**0.37**	**0.34**	**0.30**	**0.26**
RIDER PPA [5]	-	-	-	-	1.36	1.97	3.24	3.29	3.37	3.43	3.51	3.56	3.64	3.71	3.80	3.86	3.93	4.01
RIDER PPA - FUEL BENEFIT	-	-	-	-	-	-	(3.26)	(3.17)	(3.13)	(3.07)	(3.14)	(3.22)	(3.22)	(3.28)	(3.42)	(3.52)	(3.59)	(3.64)
RIDER PPA - REC PROXY	-	-	-	-	-	-	-	-	(3.33)	(1.77)	(1.03)	(0.83)	(0.61)	(0.41)	(0.43)	(0.45)	(0.47)	(0.50)
RIDER PPA - CAPACITY OFFSET	-	-	-	-	-	-	(0.35)	(0.37)	(0.37)	(0.38)	(0.40)	(0.41)	(0.42)	(0.43)	(0.44)	(0.46)	(0.47)	(0.49)
TOTAL RIDER PPA	**-**	**-**	**-**	**-**	**1.36**	**1.97**	**(0.38)**	**(0.25)**	**(3.47)**	**(1.79)**	**(1.06)**	**(0.89)**	**(0.61)**	**(0.41)**	**(0.49)**	**(0.56)**	**(0.61)**	**(0.62)**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	-	-	-	2.01	4.93	10.18	8.77	12.20	8.66	10.67	11.14	10.13	8.56	6.46	7.25	8.20	9.50	10.81
PLAN A TOTAL	**577.71**	**536.16**	**545.89**	**591.89**	**605.87**	**655.45**	**594.63**	**598.88**	**610.52**	**620.82**	**639.11**	**637.97**	**641.19**	**646.49**	**651.06**	**662.40**	**665.46**	**668.27**
CAGR PLAN A (2019 BASE)													1.0%					0.9%
CAGR PLAN A (MAY 2020 BASE)													1.7%					1.4%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Rider PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Solar only.

Extraordinarily Sensitive Information Redacted
Rate Outlook 2020 to 2035

SMALL GENERAL SERVICES BILL PROJECTION - PLAN B, DIRECTED METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 276.54	$ 276.54	$ 276.54	$ 276.54	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	[redacted]													
FUEL (MARKET FORECAST)	$ 139.52	$ 104.14	$ 102.13	$ 122.69	[redacted]													
DSM (APPROVED & PROPOSED)	$ 5.33	$ 5.33	$ 6.49	$ 6.59	[redacted]													
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16	[redacted]													
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	[redacted]													
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]													
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18	[redacted]													
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12	[redacted]													
A5 Environmental																		
RIDER E	$ 9.44	$ 9.44	$ 7.48	$ 5.99	[redacted]													
RIDER RGGI	$ -	$ -	$ -	$ 14.36	[redacted]													
RIDER CCR	$ -	$ -	$ -	$ 17.67	[redacted]													
Additional Resources in Plan B																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	$ -	$ -	$ -	$ -	[redacted]													
VCHEC 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.32	$ 1.01	$ 0.97	$ 0.95	$ 0.95	$ 0.89	$ 0.88	$ 0.83	$ 0.80	$ 0.77	$ 0.72	$ 0.67	$ 0.64	$ 0.58
RPS Program-Related Resources Plan B																		
RIDER RPS [4]	$ -	$ -	$ -	$ 1.09	$ 2.92	$ 7.41	$ 8.44	$ 11.77	$ 11.83	$ 12.11	$ 11.77	$ 10.60	$ 8.74	$ 6.44	$ 7.37	$ 8.42	$ 9.81	$ 11.16
RIDER CE [5]	$ -	$ -	$ -	$ 0.92	$ 8.95	$ 15.59	$ 23.35	$ 35.35	$ 44.35	$ 54.37	$ 65.06	$ 75.31	$ 85.21	$ 95.84	$ 106.43	$ 116.90	$ 126.45	$ 133.49
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.44)	$ (1.00)	$ (4.19)	$ (7.24)	$ (10.32)	$ (13.30)	$ (16.89)	$ (20.51)	$ (23.82)	$ (27.54)	$ (32.10)	$ (36.44)	$ (40.73)	$ (44.76)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.78)	$ (5.17)	$ (4.52)	$ (3.94)	$ (3.44)	$ (2.64)	$ (3.11)	$ (3.63)	$ (4.30)	$ (4.88)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.09)	$ (0.33)	$ (1.22)	$ (2.27)	$ (3.46)	$ (4.71)	$ (6.10)	$ (7.61)	$ (9.26)	$ (11.06)	$ (12.98)	$ (15.00)	$ (17.19)	$ (19.46)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 8.42**	**$ 14.26**	**$ 17.95**	**$ 25.85**	**$ 28.80**	**$ 31.19**	**$ 37.55**	**$ 43.25**	**$ 48.70**	**$ 54.61**	**$ 58.24**	**$ 61.84**	**$ 64.24**	**$ 64.39**
RIDER PPA [6]	$ -	$ -	$ -	$ -	$ 1.60	$ 2.31	$ 4.15	$ 5.98	$ 8.65	$ 11.04	$ 13.58	$ 16.49	$ 18.67	$ 21.77	$ 25.24	$ 28.54	$ 31.09	$ 34.55
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ (3.82)	$ (4.36)	$ (6.04)	$ (7.64)	$ (9.55)	$ (11.43)	$ (13.17)	$ (15.30)	$ (17.73)	$ (20.04)	$ (22.33)	$ (24.49)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.49)	$ (3.02)	$ (2.53)	$ (2.25)	$ (1.90)	$ (1.43)	$ (1.69)	$ (1.96)	$ (2.30)	$ (2.49)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.50)	$ (0.78)	$ (1.41)	$ (2.09)	$ (2.83)	$ (3.61)	$ (4.46)	$ (5.42)	$ (6.43)	$ (7.49)	$ (8.63)	$ (9.82)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.60**	**$ 2.31**	**$ (0.17)**	**$ 0.84**	**$ (1.30)**	**$ (1.72)**	**$ (1.32)**	**$ (0.80)**	**$ (0.86)**	**$ (0.38)**	**$ (0.61)**	**$ (0.95)**	**$ (2.17)**	**$ (2.25)**
RIDER OSW [2]	$ -	$ -	$ -	$ -	$ 9.13	$ 11.45	$ 25.99	$ 41.05	$ 49.46	$ 78.61	$ 74.81	$ 82.81	$ 81.59	$ 94.44	$ 109.32	$ 114.95	$ 145.39	$ 137.80
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.63)	$ (20.71)	$ (21.36)	$ (21.80)	$ (22.24)	$ (22.94)	$ (23.85)	$ (27.64)	$ (50.74)	$ (52.14)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.80)	$ (1.93)	$ (1.42)	$ (0.94)	$ (0.98)	$ (1.03)	$ (1.14)	$ (1.47)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.24)	$ (2.31)	$ (2.38)	$ (2.45)	$ (2.52)	$ (2.59)	$ (2.67)	$ (5.48)	$ (5.64)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9.13**	**$ 11.45**	**$ 25.99**	**$ 41.05**	**$ 46.83**	**$ 55.66**	**$ 49.34**	**$ 56.70**	**$ 55.48**	**$ 68.03**	**$ 81.90**	**$ 83.60**	**$ 88.03**	**$ 78.55**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 22.06**	**$ 35.43**	**$ 52.21**	**$ 79.51**	**$ 86.17**	**$ 97.24**	**$ 97.34**	**$ 109.75**	**$ 112.06**	**$ 128.70**	**$ 146.90**	**$ 152.91**	**$ 159.91**	**$ 151.85**
PLAN B TOTAL	**$ 577.71**	**$ 536.16**	**$ 545.89**	**$ 591.75**	**$ 607.63**	**$ 635.60**	**$ 677.38**	**$ 705.06**	**$ 750.20**	**$ 769.49**	**$ 780.59**	**$ 794.48**	**$ 801.98**	**$ 829.82**	**$ 851.98**	**$ 873.45**	**$ 893.07**	**$ 885.39**
CAGR PLAN B (2019 BASE)													3.0%					2.7%
CAGR PLAN B (MAY 2020 BASE)													3.8%					3.3%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted

Rate Outlook 2020 to 2035

SMALL GENERAL SERVICES BILL PROJECTION - PLAN C, DIRECTED METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

SMALL GENERAL SERVICE Schedule GS-1 (6,000 kWh - 15 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 276.54	$ 276.54	$ 276.54	$ 276.54	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65	$ 272.65
TRANSMISSION - RIDER T	$ 76.59	$ 76.59	$ 89.37	$ 70.55	[redacted]													
FUEL (MARKET FORECAST)	$ 139.52	$ 104.14	$ 102.13	$ 122.69														
DSM (APPROVED & PROPOSED)	$ 5.33	$ 5.33	$ 6.49	$ 6.59														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 0.16														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	$ 61.54	$ 58.22	$ 57.99	$ 65.89	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]													
STRATEGIC UNDERGROUND PLAN	$ 8.75	$ 5.90	$ 5.90	$ 9.18														
RURAL BROADBAND	$ -	$ -	$ -	$ 0.12														
A5 Environmental																		
RIDER E	$ 9.44	$ 9.44	$ 7.48	$ 5.99	[redacted]													
RIDER RGGI	$ -	$ -	$ -	$ 14.36														
RIDER CCR	$ -	$ -	$ -	$ 17.67														
Additional Resources in Plan C																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	$ -	$ -	$ -	$ -														
BEAR GARDEN 2039 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.16	$ 0.55	$ 0.46	$ 0.44	$ 0.52	$ 0.47	$ 0.43	$ 0.59	$ 0.53	$ 0.48	$ 0.43	$ 0.37	$ 0.32	$ 0.89
VCHEC 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.32	$ 1.01	$ 0.97	$ 0.95	$ 0.95	$ 0.89	$ 0.88	$ 0.83	$ 0.80	$ 0.77	$ 0.72	$ 0.67	$ 0.64	$ 0.58
BRUNSWICK 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.36	$ 0.52	$ 0.48	$ 0.49	$ 0.49	$ 0.36	$ 0.38	$ 0.37	$ 0.33	$ 0.36	$ 0.37	$ 0.32	$ 0.37	$ 0.38
GREENSVILLE 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.19	$ 0.73	$ 0.67	$ 0.62	$ 0.62	$ 0.59	$ 0.56	$ 0.58	$ 0.57	$ 0.55	$ 0.50	$ 0.63	$ 0.61	$ 0.61
WARREN 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 0.31	$ 0.29	$ 0.32	$ 0.35	$ 0.33	$ 0.35	$ 0.34	$ 0.31	$ 0.33	$ 0.32	$ 0.38	$ 0.43	$ 0.46	$ 0.43
RPS Program-Related Resources Plan C																		
RIDER RPS [4]	$ -	$ -	$ -	$ 1.09	$ 2.92	$ 7.41	$ 8.44	$ 11.77	$ 11.83	$ 12.11	$ 11.77	$ 10.60	$ 8.74	$ 6.44	$ 7.37	$ 8.42	$ 9.81	$ 11.16
RIDER CE [5]	$ -	$ -	$ -	$ 0.92	$ 8.95	$ 15.59	$ 23.35	$ 35.35	$ 44.35	$ 54.37	$ 65.06	$ 75.31	$ 85.38	$ 96.50	$ 108.16	$ 121.18	$ 132.86	$ 141.67
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (0.44)	$ (1.00)	$ (4.19)	$ (7.24)	$ (10.32)	$ (13.30)	$ (16.89)	$ (20.51)	$ (23.82)	$ (27.54)	$ (32.10)	$ (36.44)	$ (40.73)	$ (44.76)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.78)	$ (5.17)	$ (4.52)	$ (3.94)	$ (3.44)	$ (2.64)	$ (3.11)	$ (3.63)	$ (4.30)	$ (4.88)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (0.09)	$ (0.33)	$ (1.22)	$ (2.27)	$ (3.46)	$ (4.71)	$ (6.10)	$ (7.61)	$ (9.26)	$ (11.06)	$ (12.98)	$ (15.49)	$ (18.11)	$ (20.85)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 0.92**	**$ 8.42**	**$ 14.26**	**$ 17.95**	**$ 25.85**	**$ 28.80**	**$ 31.19**	**$ 37.55**	**$ 43.25**	**$ 48.86**	**$ 55.26**	**$ 59.96**	**$ 65.63**	**$ 69.72**	**$ 71.18**
RIDER PPA [6]	$ -	$ -	$ -	$ -	$ 1.60	$ 2.31	$ 4.15	$ 5.98	$ 8.65	$ 11.05	$ 13.61	$ 16.49	$ 18.68	$ 21.78	$ 25.25	$ 30.36	$ 34.54	$ 39.70
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ (3.82)	$ (4.36)	$ (6.04)	$ (7.64)	$ (9.55)	$ (11.43)	$ (13.17)	$ (15.30)	$ (17.73)	$ (20.04)	$ (22.33)	$ (24.49)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.49)	$ (3.02)	$ (2.53)	$ (2.25)	$ (1.90)	$ (1.43)	$ (1.69)	$ (1.96)	$ (2.30)	$ (2.49)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.50)	$ (0.78)	$ (1.41)	$ (2.09)	$ (2.83)	$ (3.61)	$ (4.46)	$ (5.42)	$ (6.43)	$ (7.75)	$ (9.13)	$ (10.57)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.60**	**$ 2.31**	**$ (0.17)**	**$ 0.84**	**$ (1.30)**	**$ (1.71)**	**$ (1.28)**	**$ (0.80)**	**$ (0.84)**	**$ (0.38)**	**$ (0.59)**	**$ 0.61**	**$ 0.79**	**$ 2.15**
RIDER OSW [2]	$ -	$ -	$ -	$ -	$ 9.13	$ 11.45	$ 25.99	$ 41.05	$ 49.46	$ 78.61	$ 74.81	$ 82.81	$ 81.59	$ 94.44	$ 109.32	$ 114.95	$ 145.39	$ 137.80
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.63)	$ (20.71)	$ (21.36)	$ (21.80)	$ (22.24)	$ (22.94)	$ (23.85)	$ (27.64)	$ (50.74)	$ (52.14)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1.80)	$ (1.93)	$ (1.42)	$ (0.94)	$ (0.98)	$ (1.03)	$ (1.14)	$ (1.47)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2.24)	$ (2.31)	$ (2.38)	$ (2.45)	$ (2.52)	$ (2.59)	$ (2.67)	$ (5.48)	$ (5.64)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9.13**	**$ 11.45**	**$ 25.99**	**$ 41.05**	**$ 46.83**	**$ 55.66**	**$ 49.34**	**$ 56.70**	**$ 55.48**	**$ 68.03**	**$ 81.90**	**$ 83.60**	**$ 88.03**	**$ 78.55**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 2.01**	**$ 22.06**	**$ 35.43**	**$ 52.21**	**$ 79.51**	**$ 86.17**	**$ 97.25**	**$ 97.37**	**$ 109.75**	**$ 112.24**	**$ 129.36**	**$ 148.64**	**$ 158.26**	**$ 168.35**	**$ 163.03**
PLAN C TOTAL	**$ 577.71**	**$ 536.16**	**$ 545.89**	**$ 591.75**	**$ 609.36**	**$ 638.05**	**$ 679.67**	**$ 707.34**	**$ 752.69**	**$ 771.59**	**$ 782.63**	**$ 796.72**	**$ 804.16**	**$ 832.53**	**$ 855.75**	**$ 880.85**	**$ 903.19**	**$ 898.61**
CAGR PLAN C (2019 BASE)													3.1%					2.8%
CAGR PLAN C (MAY 2020 BASE)													3.9%					3.4%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted
Rate Outlook 2020 to 2035

LARGE GENERAL SERVICES BILL PROJECTION - PLAN A, DIRECTED METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	131,196.69	131,196.69	131,196.69	131,196.69	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15	119,032.15
TRANSMISSION - RIDER T	37,760.00	37,760.00	42,270.00	45,261.35	[redacted]													
FUEL (MARKET FORECAST)	139,524.00	104,142.00	102,126.00	122,688.00	[redacted]													
DSM (APPROVED & PROPOSED)	150.00	150.00	6.49	54.00	[redacted]													
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	-	-	-	162.00	[redacted]													
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	36,670.00	34,070.00	33,750.00	34,650.00	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	-	-	-	-	[redacted]													
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	-	-	-	-	[redacted]													
STRATEGIC UNDERGROUND PLAN	-	-	-	-	[redacted]													
RURAL BROADBAND	-	-	-	20.00	[redacted]													
A5 Environmental																		
RIDER E	5,560.00	5,560.00	7.48	3,140.00	[redacted]													
RIDER RGGI	-	-	-	14,358.00	[redacted]													
RIDER CCR	-	-	-	17,670.00	[redacted]													
Additional Resources in Plan A																		
GAS CT (2026 & 2027)	-	-	-	-	[redacted]													
BIOMASS - 2023 RETIREMENT	-	-	-	-	2,030.00	1,690.00	(1,480.00)	(1,830.00)	(1,900.00)	(1,980.00)	(2,610.00)	(310.00)	-	-	-	-	-	-
VCHEC - 2023 RETIREMENT	-	-	-	-	1,280.00	29,380.00	(8,980.00)	(8,600.00)	(8,570.00)	(8,550.00)	(8,470.00)	(8,350.00)	(8,330.00)	(8,340.00)	(8,090.00)	(8,050.00)	(8,000.00)	(8,470.00)
RPS Program-Related Resources Plan A																		
RIDER RPS [4]	-	-	-	1,092.00	2,916.00	7,410.00	8,436.00	11,772.00	11,832.00	12,108.00	11,772.00	10,596.00	8,742.00	6,444.00	7,368.00	8,424.00	9,810.00	11,160.00
RIDER CE [5]	-	-	-	480.00	560.00	780.00	730.00	700.00	670.00	650.00	630.00	620.00	600.00	590.00	570.00	560.00	550.00	530.00
RIDER CE - FUEL BENEFIT	-	-	-	-	(258.00)	(402.00)	(372.00)	(360.00)	(354.00)	(348.00)	(354.00)	(366.00)	(366.00)	(372.00)	(390.00)	(396.00)	(408.00)	(414.00)
RIDER CE - REC PROXY VALUE	-	-	-	-	-	-	-	-	(330.00)	(240.00)	(132.00)	(90.00)	(66.00)	(42.00)	(48.00)	(48.00)	(48.00)	(54.00)
RIDER CE - CAPACITY OFFSET	-	-	-	-	-	(40.00)	(60.00)	(60.00)	(60.00)	(60.00)	(70.00)	(70.00)	(70.00)	(70.00)	(70.00)	(80.00)	(80.00)	(80.00)
TOTAL RIDER CE	**-**	**-**	**-**	**480.00**	**302.00**	**338.00**	**298.00**	**280.00**	**(74.00)**	**2.00**	**74.00**	**94.00**	**98.00**	**106.00**	**62.00**	**36.00**	**14.00**	**(18.00)**
RIDER PPA [5]	-	-	-	-	1,350.00	1,956.00	3,214.00	3,260.00	3,322.00	3,386.00	3,450.00	3,514.00	3,584.00	3,654.00	3,730.00	3,794.00	3,870.00	3,936.00
RIDER PPA - FUEL BENEFIT	-	-	-	-	-	-	(3,264.00)	(3,174.00)	(3,132.00)	(3,072.00)	(3,144.00)	(3,216.00)	(3,222.00)	(3,282.00)	(3,420.00)	(3,516.00)	(3,588.00)	(3,636.00)
RIDER PPA - REC PROXY	-	-	-	-	-	-	-	-	(3,330.00)	(1,770.00)	(1,032.00)	(834.00)	(612.00)	(408.00)	(426.00)	(450.00)	(474.00)	(504.00)
RIDER PPA - CAPACITY OFFSET	-	-	-	-	-	-	(220.00)	(220.00)	(230.00)	(240.00)	(250.00)	(250.00)	(260.00)	(270.00)	(280.00)	(280.00)	(290.00)	(300.00)
TOTAL RIDER PPA	**-**	**-**	**-**	**-**	**1,350.00**	**1,956.00**	**(270.00)**	**(134.00)**	**(3,370.00)**	**(1,696.00)**	**(976.00)**	**(786.00)**	**(510.00)**	**(306.00)**	**(396.00)**	**(452.00)**	**(482.00)**	**(504.00)**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	-	-	-	1,572.00	4,568.00	9,704.00	8,464.00	11,918.00	8,388.00	10,414.00	10,870.00	9,904.00	8,330.00	6,244.00	7,034.00	8,008.00	9,342.00	10,638.00
PLAN A TOTAL	**350,860.69**	**312,878.69**	**309,356.66**	**370,772.04**	**372,426.05**	**416,346.60**	**376,510.43**	**381,042.71**	**388,480.61**	**394,937.75**	**408,789.38**	**406,357.33**	**408,188.87**	**412,882.95**	**417,786.50**	**429,122.44**	**432,699.66**	**436,024.19**
CAGR PLAN A (2019 BASE)													1.4%					1.4%
CAGR PLAN A (MAY 2020 BASE)													2.5%					2.1%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Rider PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Solar only.

Extraordinarily Sensitive Information Redacted
Rate Outlook 2020 to 2035

LARGE GENERAL SERVICES BILL PROJECTION - PLAN B, DIRECTED METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15
TRANSMISSION - RIDER T	$ 37,760.00	$ 37,760.00	$ 42,270.00	$ 45,261.35	[redacted]													
FUEL (MARKET FORECAST)	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00														
DSM (APPROVED & PROPOSED)	$ 150.00	$ 150.00	$ 6.49	$ 54.00														
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00														
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -														
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]													
STRATEGIC UNDERGROUND PLAN	$ -	$ -	$ -	$ -														
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00														
A5 Environmental																		
RIDER E	$ 5,560.00	$ 5,560.00	$ 7.48	$ 3,140.00	[redacted]													
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00														
RIDER CCR	$ -	$ -	$ -	$ 17,670.00														
Additional Resources in Plan B																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	$ -	$ -	$ -	$ -														
VCHEC 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 200.00	$ 630.00	$ 610.00	$ 590.00	$ 590.00	$ 560.00	$ 550.00	$ 520.00	$ 500.00	$ 480.00	$ 450.00	$ 420.00	$ 390.00	$ 360.00
RPS Program-Related Resources Plan B																		
RIDER RPS [4]	$ -	$ -	$ -	$ 1,092.00	$ 2,916.00	$ 7,410.00	$ 8,436.00	$ 11,772.00	$ 11,832.00	$ 12,108.00	$ 11,772.00	$ 10,596.00	$ 8,742.00	$ 6,444.00	$ 7,368.00	$ 8,424.00	$ 9,810.00	$ 11,160.00
RIDER CE [5]	$ -	$ -	$ -	$ 480.00	$ 5,540.00	$ 9,640.00	$ 14,440.00	$ 21,880.00	$ 27,430.00	$ 33,630.00	$ 40,250.00	$ 46,570.00	$ 52,730.00	$ 59,300.00	$ 65,840.00	$ 72,330.00	$ 78,230.00	$ 82,570.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (438.00)	$ (1,002.00)	$ (4,188.00)	$ (7,236.00)	$ (10,320.00)	$ (13,302.00)	$ (16,890.00)	$ (20,514.00)	$ (23,820.00)	$ (27,540.00)	$ (32,100.00)	$ (36,438.00)	$ (40,728.00)	$ (44,760.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,776.00)	$ (5,166.00)	$ (4,518.00)	$ (3,936.00)	$ (3,438.00)	$ (2,640.00)	$ (3,108.00)	$ (3,630.00)	$ (4,296.00)	$ (4,884.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (50.00)	$ (210.00)	$ (750.00)	$ (1,400.00)	$ (2,130.00)	$ (2,910.00)	$ (3,780.00)	$ (4,700.00)	$ (5,720.00)	$ (6,830.00)	$ (8,030.00)	$ (9,280.00)	$ (10,630.00)	$ (12,030.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 5,052.00**	**$ 8,428.00**	**$ 9,502.00**	**$ 13,244.00**	**$ 13,204.00**	**$ 12,252.00**	**$ 15,062.00**	**$ 17,420.00**	**$ 19,752.00**	**$ 22,290.00**	**$ 22,602.00**	**$ 22,982.00**	**$ 22,576.00**	**$ 20,896.00**
RIDER PPA [6]	$ -	$ -	$ -	$ -	$ 1,590.00	$ 2,302.00	$ 4,028.00	$ 5,762.00	$ 8,218.00	$ 10,498.00	$ 12,802.00	$ 15,480.00	$ 17,622.00	$ 20,376.00	$ 23,494.00	$ 26,432.00	$ 28,524.00	$ 31,486.00
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,816.00)	$ (4,356.00)	$ (6,042.00)	$ (7,644.00)	$ (9,546.00)	$ (11,430.00)	$ (13,170.00)	$ (15,300.00)	$ (17,730.00)	$ (20,040.00)	$ (22,326.00)	$ (24,492.00)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,490.00)	$ (3,018.00)	$ (2,526.00)	$ (2,250.00)	$ (1,896.00)	$ (1,434.00)	$ (1,686.00)	$ (1,962.00)	$ (2,304.00)	$ (2,490.00)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (310.00)	$ (490.00)	$ (880.00)	$ (1,290.00)	$ (1,750.00)	$ (2,230.00)	$ (2,760.00)	$ (3,350.00)	$ (3,970.00)	$ (4,640.00)	$ (5,340.00)	$ (6,070.00)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,590.00**	**$ 2,302.00**	**$ (98.00)**	**$ 916.00**	**$ (1,194.00)**	**$ (1,454.00)**	**$ (1,020.00)**	**$ (430.00)**	**$ (204.00)**	**$ 292.00**	**$ 108.00**	**$ (210.00)**	**$ (1,446.00)**	**$ (1,566.00)**
RIDER OSW [2]	$ -	$ -	$ -	$ -	$ 5,650.00	$ 7,090.00	$ 16,080.00	$ 25,400.00	$ 30,600.00	$ 48,630.00	$ 46,280.00	$ 51,240.00	$ 50,480.00	$ 58,430.00	$ 67,630.00	$ 71,120.00	$ 89,950.00	$ 85,250.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,634.00)	$ (20,706.00)	$ (21,360.00)	$ (21,804.00)	$ (22,242.00)	$ (22,944.00)	$ (23,850.00)	$ (27,642.00)	$ (50,736.00)	$ (52,140.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,800.00)	$ (1,932.00)	$ (1,422.00)	$ (942.00)	$ (978.00)	$ (1,032.00)	$ (1,140.00)	$ (1,470.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,390.00)	$ (1,430.00)	$ (1,470.00)	$ (1,520.00)	$ (1,560.00)	$ (1,610.00)	$ (1,650.00)	$ (3,400.00)	$ (3,500.00)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,650.00**	**$ 7,090.00**	**$ 16,080.00**	**$ 25,400.00**	**$ 27,966.00**	**$ 26,534.00**	**$ 21,690.00**	**$ 26,034.00**	**$ 25,296.00**	**$ 32,984.00**	**$ 41,192.00**	**$ 40,796.00**	**$ 34,674.00**	**$ 28,140.00**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 15,208.00**	**$ 25,230.00**	**$ 33,920.00**	**$ 51,332.00**	**$ 51,808.00**	**$ 49,440.00**	**$ 47,504.00**	**$ 53,620.00**	**$ 53,586.00**	**$ 62,010.00**	**$ 71,270.00**	**$ 71,992.00**	**$ 65,614.00**	**$ 58,630.00**
PLAN B TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 309,356.66**	**$ 370,692.04**	**$ 369,642.05**	**$ 402,404.60**	**$ 419,094.43**	**$ 435,192.71**	**$ 455,422.61**	**$ 464,149.75**	**$ 466,739.38**	**$ 473,457.33**	**$ 477,732.87**	**$ 497,230.95**	**$ 511,402.50**	**$ 527,882.44**	**$ 534,977.66**	**$ 529,512.19**
CAGR PLAN B (2019 BASE)													2.8%					2.6%
CAGR PLAN B (MAY 2020 BASE)													4.0%					3.4%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.

Extraordinarily Sensitive Information Redacted

Rate Outlook 2020 to 2035

LARGE GENERAL SERVICES BILL PROJECTION - PLAN C, DIRECTED METHODOLOGY

Rate projections are not final. Rates are subject to regulatory approval.
Certain line items potentially eligible for customer credit reinvestment offset under Va. Code.
Rate projections assume return on equity of 9.20%.

LARGE GENERAL SERVICE Schedule GS-4 (6,000,000 kWh - 10,000 kW)	2019 DEC 2019	2020 MAY 1, 2020	2020 DEC 2020	2021 DEC 2021	2022 DEC 2022	2023 DEC 2023	2024 DEC 2024	2025 DEC 2025	2026 DEC 2026	2027 DEC 2027	2028 DEC 2028	2029 DEC 2029	2030 DEC 2030	2031 DEC 2031	2032 DEC 2032	2033 DEC 2033	2034 DEC 2034	2035 DEC 2035
DISTRIBUTION & GENERATION (BASE) [1]	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 131,196.69	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15	$ 119,032.15
TRANSMISSION - RIDER T	$ 37,760.00	$ 37,760.00	$ 42,270.00	$ 45,261.35	[redacted]													
FUEL (MARKET FORECAST)	$ 139,524.00	$ 104,142.00	$ 102,126.00	$ 122,688.00	[redacted]													
DSM (APPROVED & PROPOSED)	$ 150.00	$ 150.00	$ 6.49	$ 54.00	[redacted]													
RIDER PIPP - UNIVERSAL SERVICE FEE [2]	$ -	$ -	$ -	$ 162.00	[redacted]													
Generation Infrastructure																		
EXISTING GENERATION RIDERS [3]	$ 36,670.00	$ 34,070.00	$ 33,750.00	$ 34,570.00	[redacted]													
RIDER SNA - NUCLEAR SUBSEQUENT LICENSE RENEWAL	$ -	$ -	$ -	$ -	[redacted]													
Distribution Infrastructure																		
GT PLAN (APPROVED PHASE 1)	$ -	$ -	$ -	$ -	[redacted]													
STRATEGIC UNDERGROUND PLAN	$ -	$ -	$ -	$ -	[redacted]													
RURAL BROADBAND	$ -	$ -	$ -	$ 20.00	[redacted]													
A5 Environmental																		
RIDER E	$ 5,560.00	$ 5,560.00	$ 7.48	$ 3,140.00	[redacted]													
RIDER RGGI	$ -	$ -	$ -	$ 14,358.00	[redacted]													
RIDER CCR	$ -	$ -	$ -	$ 17,670.00	[redacted]													
Additional Resources in Plan C																		
INCREMENTAL GENERIC DSM	$ -	$ -	$ -	$ -	[redacted]													
INCREMENTAL GT PLAN (PHASE 2 + FUTURE PHASES)	$ -	$ -	$ -	$ -	[redacted]													
BEAR GARDEN 2039 RETIREMENT	$ -	$ -	$ -	$ -	$ 100.00	$ 340.00	$ 290.00	$ 270.00	$ 320.00	$ 300.00	$ 270.00	$ 360.00	$ 330.00	$ 300.00	$ 260.00	$ 230.00	$ 200.00	$ 560.00
VCHEC 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 200.00	$ 630.00	$ 610.00	$ 590.00	$ 590.00	$ 560.00	$ 550.00	$ 520.00	$ 500.00	$ 480.00	$ 450.00	$ 420.00	$ 390.00	$ 360.00
BRUNSWICK 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 230.00	$ 320.00	$ 300.00	$ 310.00	$ 300.00	$ 230.00	$ 230.00	$ 230.00	$ 210.00	$ 220.00	$ 230.00	$ 200.00	$ 230.00	$ 240.00
GREENSVILLE 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 120.00	$ 450.00	$ 410.00	$ 390.00	$ 380.00	$ 370.00	$ 350.00	$ 360.00	$ 350.00	$ 340.00	$ 310.00	$ 390.00	$ 380.00	$ 380.00
WARREN 2045 RETIREMENT	$ -	$ -	$ -	$ -	$ 190.00	$ 180.00	$ 200.00	$ 220.00	$ 200.00	$ 210.00	$ 210.00	$ 190.00	$ 200.00	$ 200.00	$ 240.00	$ 270.00	$ 290.00	$ 270.00
RPS Program-Related Resources Plan C																		
RIDER RPS [4]	$ -	$ -	$ -	$ 1,092.00	$ 2,916.00	$ 7,410.00	$ 8,436.00	$ 11,772.00	$ 11,832.00	$ 12,108.00	$ 11,772.00	$ 10,596.00	$ 8,742.00	$ 6,444.00	$ 7,368.00	$ 8,424.00	$ 9,810.00	$ 11,160.00
RIDER CE [5]	$ -	$ -	$ -	$ 480.00	$ 5,540.00	$ 9,640.00	$ 14,440.00	$ 21,880.00	$ 27,430.00	$ 33,630.00	$ 40,250.00	$ 46,570.00	$ 52,830.00	$ 59,700.00	$ 66,910.00	$ 74,970.00	$ 82,200.00	$ 87,630.00
RIDER CE - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ (438.00)	$ (1,002.00)	$ (4,188.00)	$ (7,236.00)	$ (10,320.00)	$ (13,302.00)	$ (16,890.00)	$ (20,514.00)	$ (23,820.00)	$ (27,540.00)	$ (32,100.00)	$ (36,438.00)	$ (40,728.00)	$ (44,760.00)
RIDER CE - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,776.00)	$ (5,166.00)	$ (4,518.00)	$ (3,936.00)	$ (3,438.00)	$ (2,640.00)	$ (3,108.00)	$ (3,630.00)	$ (4,296.00)	$ (4,884.00)
RIDER CE - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ (50.00)	$ (210.00)	$ (750.00)	$ (1,400.00)	$ (2,130.00)	$ (2,910.00)	$ (3,780.00)	$ (4,700.00)	$ (5,720.00)	$ (6,830.00)	$ (8,030.00)	$ (9,580.00)	$ (11,200.00)	$ (12,890.00)
TOTAL RIDER CE	**$ -**	**$ -**	**$ -**	**$ 480.00**	**$ 5,052.00**	**$ 8,428.00**	**$ 9,502.00**	**$ 13,244.00**	**$ 13,204.00**	**$ 12,252.00**	**$ 15,062.00**	**$ 17,420.00**	**$ 19,852.00**	**$ 22,690.00**	**$ 23,672.00**	**$ 25,322.00**	**$ 25,976.00**	**$ 25,096.00**
RIDER PPA [6]	$ -	$ -	$ -	$ -	$ 1,590.00	$ 2,302.00	$ 4,028.00	$ 5,762.00	$ 8,218.00	$ 10,504.00	$ 12,848.00	$ 15,480.00	$ 17,622.00	$ 20,388.00	$ 23,512.00	$ 27,572.00	$ 30,704.00	$ 34,742.00
RIDER PPA - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,816.00)	$ (4,356.00)	$ (6,042.00)	$ (7,644.00)	$ (9,546.00)	$ (11,430.00)	$ (13,170.00)	$ (15,300.00)	$ (17,730.00)	$ (20,040.00)	$ (22,326.00)	$ (24,492.00)
RIDER PPA - REC PROXY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,490.00)	$ (3,018.00)	$ (2,526.00)	$ (2,250.00)	$ (1,896.00)	$ (1,434.00)	$ (1,686.00)	$ (1,962.00)	$ (2,304.00)	$ (2,490.00)
RIDER PPA - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ (310.00)	$ (490.00)	$ (880.00)	$ (1,290.00)	$ (1,750.00)	$ (2,230.00)	$ (2,760.00)	$ (3,350.00)	$ (3,970.00)	$ (4,800.00)	$ (5,650.00)	$ (6,530.00)
TOTAL RIDER PPA	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,590.00**	**$ 2,302.00**	**$ (98.00)**	**$ 916.00**	**$ (1,194.00)**	**$ (1,448.00)**	**$ (974.00)**	**$ (430.00)**	**$ (204.00)**	**$ 304.00**	**$ 126.00**	**$ 770.00**	**$ 424.00**	**$ 1,230.00**
RIDER OSW [2]	$ -	$ -	$ -	$ -	$ 5,650.00	$ 7,090.00	$ 16,080.00	$ 25,400.00	$ 30,600.00	$ 48,630.00	$ 46,280.00	$ 51,240.00	$ 50,480.00	$ 58,430.00	$ 67,630.00	$ 71,120.00	$ 89,950.00	$ 85,250.00
RIDER OSW - FUEL BENEFIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,634.00)	$ (20,706.00)	$ (21,360.00)	$ (21,804.00)	$ (22,242.00)	$ (22,944.00)	$ (23,850.00)	$ (27,642.00)	$ (50,736.00)	$ (52,140.00)
RIDER OSW - REC PROXY VALUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,800.00)	$ (1,932.00)	$ (1,422.00)	$ (942.00)	$ (978.00)	$ (1,032.00)	$ (1,140.00)	$ (1,470.00)
RIDER OSW - CAPACITY OFFSET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,390.00)	$ (1,430.00)	$ (1,470.00)	$ (1,520.00)	$ (1,560.00)	$ (1,610.00)	$ (1,650.00)	$ (3,400.00)	$ (3,500.00)
TOTAL OFFSHORE WIND (2 PHASES TOTALING 5,154 MW) [7]	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,650.00**	**$ 7,090.00**	**$ 16,080.00**	**$ 25,400.00**	**$ 27,966.00**	**$ 26,534.00**	**$ 21,690.00**	**$ 26,034.00**	**$ 25,296.00**	**$ 32,984.00**	**$ 41,192.00**	**$ 40,796.00**	**$ 34,674.00**	**$ 28,140.00**
RPS PROGRAM-RELATED RESOURCES SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ 1,572.00**	**$ 15,208.00**	**$ 25,230.00**	**$ 33,920.00**	**$ 51,332.00**	**$ 51,808.00**	**$ 49,446.00**	**$ 47,550.00**	**$ 53,620.00**	**$ 53,686.00**	**$ 62,422.00**	**$ 72,358.00**	**$ 75,312.00**	**$ 70,884.00**	**$ 65,626.00**
PLAN C TOTAL	**$ 350,860.69**	**$ 312,878.69**	**$ 309,356.66**	**$ 370,692.04**	**$ 370,840.05**	**$ 404,060.60**	**$ 420,654.43**	**$ 436,754.71**	**$ 457,162.61**	**$ 465,589.75**	**$ 468,139.38**	**$ 475,005.33**	**$ 479,150.87**	**$ 499,044.95**	**$ 513,872.50**	**$ 532,586.44**	**$ 541,269.66**	**$ 537,688.19**
CAGR PLAN C (2019 BASE)													2.9%					2.7%
CAGR PLAN C (MAY 2020 BASE)													4.1%					3.5%

[1] Publicly available, annualized tariff rates consistent with filing in Case No. PUR-2021-00058. No future change modeled.
[2] No assumptions modeled for exemptions to Riders OSW & PIPP.
[3] Riders B, R, S, W, BW, GV, US-2, US-3 and US-4.
[4] Includes the cost of purchases plus the cost of the REC proxy value from Company-owned facilities.
[5] Includes CE-1 and CE-2 projects, generic solar, distributed solar, and storage.
[6] Includes CE-2 PPAs, generic solar and storage.
[7] Assumes the build-out of two phases totaling 5,154 MW. Additional details specific to the Phase I CVOW project will be included in a Q4 2021 filing.