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Case No. PUR-2022-00070
Sponsor: APPALACHIAN VOICES
Exhibit No. 16
Witness: GREGORY ABBOTT
Bailiff: CHRISTINE D. MCLAUGHLIN

Summary of the Direct Testimony of Gregory Abbott

My testimony provides an overview of RGGI and how it is designed to send a market signal to fossil fuel generators to achieve lower CO_2 emissions over time. Further, my testimony provides a discussion of recent trends in energy markets. My testimony also examines the inconsistencies between Dominion's generation planning and its actual operational practices. Lastly, my testimony examines the prudency of certain RGGI compliance costs in light of the actual unit dispatch practices employed by Dominion for its coal units that are subject to RGGI compliance. I focus my analysis on those hours of dispatch when Dominion self-scheduled its coal units that are subject to RGGI into PJM's energy markets under a must-run dispatch status and on the RGGI costs incurred at those units during the must-run dispatch hours that were uneconomic compared to the market clearing energy price.

Dominion's modeling assumption in this case is that its fossil fuel generation units are dispatched by the PJM system operator on an economic basis. However, in actual practice, Dominion frequently self-schedules its coal units under must-run dispatch. For merchant generators, the competitive operation of the PJM energy markets provides the market discipline of a competitive price signal to cost effectively achieve RGGI compliance. However, a vertically integrated utility like Dominion could bear losses from uneconomic must-run dispatch of its fossil fuel generating units because the costs would be borne, subject to Commission approval, by captive customers.

Given this dynamic, it may be incumbent on the Commission to intervene to ensure that Dominion's self-scheduling practices do not distort the competitive market resulting in customers paying unreasonable and unnecessary costs. It is Environmental Respondent's position that Dominion should not have a blank check to recover all RGGI costs from uneconomic must-run dispatch that was solely a result of Dominion management decisions that are contrary to the competitive market. Should Dominion be able to recover all such costs with impunity, not only would this subvert the policy goals of RGGI by unnecessarily increasing the tons of CO_2 emitted, it would also unnecessarily increase the costs of RGGI compliance borne by ratepayers.

For the period August 2022 through January 2023, I recommend, at a minimum, that the RGGI costs incurred during the uneconomic must-run hours for Dominion's coal units that were not required for testing or to meet the DEQ biomass permit requirement at VCHEC be disallowed as unnecessary RGGI compliance costs. This recommendation results in the disallowance of $1.1 million of RGGI compliance costs as unnecessary. Based on the evidence in this case, I do not believe that Dominion has established that these costs are necessary or reasonable and prudent.

In addition, I believe the Commission has the discretion to also disallow RGGI costs associated with uneconomic must-run dispatch at VCHEC to meet the DEQ biomass permit requirement. Should the Commission find that these RGGI compliance costs are not necessary or reasonable and prudent, this would increase the disallowance of RGGI compliance costs from $1.1 million to $2.5 million for the period August 2022 through January 2023.

I further recommend that Dominion perform a similar analysis in future Rider RGGI true-up proceedings to determine any unnecessary RGGI compliance costs that are incurred after January 2023.

Q1. PLEASE STATE YOUR NAME AND ADDRESS AND YOUR ROLE WITH THE ENVIRONMENTAL RESPONDENT.

A1. My name is Gregory Abbott, and my address is 8610 Sunview Lane, North Chesterfield, VA. My expert testimony in this proceeding is on behalf of Appalachian Voices ("Environmental Respondent").

Q2. PLEASE SUMMARIZE YOUR EXPERIENCE IN ELECTRIC UTILITY REGULATION IN VIRGINIA.

A2. I was previously employed as a member of the Commission Staff and retired in 2022 as a Deputy Director after 24 years of service in the Commission's Division of Public Utility Regulation. I have extensive experience in the regulation of electric, gas, water and sewer utilities located in the Commonwealth. This experience ranges from general rate increase applications, class cost of service, rate design, Integrated Resource Plans ("IRPs"), generation certificates, Renewable Portfolio Standard ("RPS") cases, coal ash disposal, rate adjustment clauses ("RACs"), Demand-Side Management, PJM matters, weather normalization adjustments, CARE plans, and pole attachments. I have testified before the Commission in scores of cases and a representative list of cases is provided in Attachment GLA-1.

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A3. Environmental Respondent retained my services to review and investigate Dominion Energy Virginia's ("Dominion") petition for reinstatement of a rate adjustment clause ("RAC"), designated Rider RGGI, to recover costs incurred to comply with the requirements of the Regional Greenhouse Gas Initiative ("RGGI"). My testimony provides an overview of RGGI and how it is designed to send a market signal to fossil fuel generators to achieve lower CO_2 emissions over time. Further, my testimony provides a discussion of recent trends in energy markets. My testimony also examines the inconsistencies between Dominion's generation planning and its actual operational practices. Lastly, my testimony examines the prudency of certain RGGI compliance costs in light of the actual unit dispatch practices employed by Dominion for its coal units that are subject to RGGI compliance. I focus my analysis on those hours of dispatch when Dominion self-scheduled its coal units that are subject to RGGI into PJM's energy markets under a must-run dispatch status and the RGGI costs incurred at those units during the must-run dispatch hours that were uneconomic compared to the market clearing energy price.

OVERVIEW OF RGGI

Q4. PLEASE PROVIDE A DESCRIPTION OF RGGI AND ITS POLICY OBJECTIVES.

A4. RGGI is a "cap and trade" market mechanism to cap and reduce CO_2 emissions from the electric power sector. It is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, Virginia, and Vermont. Fossil fuel electric power generators, including non-utility independent power producers, with a capacity of 25 megawatts ("MWs") or greater are required to hold CO_2 emission allowances equal to their CO_2 emissions. One CO_2 allowance is required for every ton of carbon dioxide emitted from the power plant. The required offsetting CO_2 emission allowances must be purchased by each fossil fuel generator.

Each of the RGGI member states is allocated the number of CO_2 emission allowances corresponding to its share of the overall RGGI cap. Generally, each member state must submit its CO_2 emission allowances for sale in the quarterly RGGI auctions with the revenues received from these sales flowing back to each state. The supply of allowances, or "cap," is ratcheted down each year, which is how RGGI reduces CO_2 emissions over time.

Q5. PLEASE ELABORATE ON HOW RGGI OPERATES IN ACTUAL PRACTICE TO REDUCE CO_2 EMISSIONS.

A5. Essentially, RGGI levies a charge (cost of allowances) on fossil fuel generation as a cost associated with polluting the air with carbon dioxide, payable by electric generators located in each RGGI state. The RGGI allowance cost is included in the hourly unit dispatch cost for each fossil fuel unit subsequently leading to a higher unit dispatch cost. To the extent that these fossil fuel generators bid these unit dispatch costs into competitive energy markets on an economic basis, the generation from these units will not clear the market at the same frequency or in the same amounts as the units would have absent the RGGI allowance costs. Thus, both the amount of energy produced from fossil fuel generators and the associated tons of CO_2 emissions will be lower as a result. It is important to note, however, for RGGI to operate efficiently and as intended, that a competitive energy market is required. Generally speaking, RGGI has worked as intended given the predominance of merchant generators in the RGGI states. Even in Virginia, about 25-30 percent of power plant CO_2 emissions come from merchant generators.

Vertically integrated utilities such as Dominion, however, require special attention because without sufficient oversight, a monopoly utility may not react to market forces in the same way as a merchant generator. This is not an issue that is specific to RGGI, and highlights a critical function of the Commission—to ensure that utilities are minimizing costs and not taking advantage of their captive customers. In other words, the Commission should make sure that Dominion operations respond to market signals in a manner that reduces customer costs instead of simply ignoring the market signal at ratepayer expense.

OVERVIEW OF ENERGY MARKETS

Q6. PLEASE DESCRIBE THE DEVELOPMENT TRENDS OF THE MODERN GRID AND HOW THESE TRENDS IMPACT THE CURRENT AND FUTURE COMPATABILITY OF COAL UNITS.

A6. In May 2020, the U.S. Energy Information Administration ("EIA") reported[1] that in 2019, for the first time in over 130 years, U.S. annual energy consumption from renewable energy surpassed that of coal. The EIA went on to report that over the past decade coal consumption has decreased and total renewable energy consumption increased. This trend of increased renewable energy generation – paired with historically low natural gas prices – has fundamentally changed the way the electric grid is operated and thus has necessitated a change in how existing resources are utilized. Historically, coal-fired electricity generation was used to provide baseload power. Providing baseload power worked well for coal-fired generators, because these generators operate best when run at a steady, constant level for extended periods of time. Completely shutting down a coal-fired unit and then restarting it incurs substantial cost and requires lead time to allow the unit to "ramp up" to the necessary level of output.

In the last ten years or so, however, two developments have tended to push coal-fired generation out of its historic baseload role. First, natural gas prices have been much lower than in previous years.[2] That, paired with technological improvements for natural

[1] EIA, *U.S. Renewable Energy Consumption Surpasses Coal for the First Time in over 130 Years* (May 28, 2020), https://www.eia.gov/todayinenergy/detail.php?id=43895.

[2] It should be noted that recent geopolitical pressures have roiled global energy markets which has had an upward impact on both natural gas and coal prices and the level of volatility in those markets.

gas-fired combined cycles' heat rates, has caused natural gas to supplant coal in Virginia as the primary baseload fossil fuel. Additionally, the proliferation of low-cost renewable energy has placed downward pressure on wholesale energy prices since renewables have virtually zero dispatch cost.

Today, coal units often operate more as intermediate resources that must respond more dynamically to market driven electricity needs. This creates tension because coal units operate best when they are run steadily and at a relatively constant level of output and thus simply cannot dynamically respond to fluctuating power prices in intermediate hours. The high start-up costs, requirement for long run times, and decreasing amount of market demand for coal-fired generation present challenges to utilities, which must economically justify continued use of these aging units. Given the planned increase of renewable energy additions to the electric grid, the relevance and economic viability of coal-powered electricity generation is expected to continue to decline.[3]

MUST-RUN DISPATCH VERSUS ECONOMIC DISPATCH

Q7. WHAT IS DOMINION'S MODELING ASSUMPTION WITH REGARD TO COAL UNIT DISPATCH?

A7. In PJM, a power plant operator has several different unit commitment options when offering a unit:

- Economic – the unit is available for dispatch by the PJM system operator on an economic basis;

[3] Ethan Howland, *Coal Plant Owners Seek to Shut 3.2 GW in PJM in Face of Economic, Regulatory and Market Pressures*, Utility Dive (Mar. 22, 2022), https://www.utilitydive.com/news/coal-plant-owners-seek-to-retire-power-in-pjm/620781/.

- Must-Run dispatch – the unit is self-scheduled by its owner to run at a set output level regardless of whether it would have otherwise been selected to run on an economic basis;
- Unavailable – the unit is unavailable for dispatch due to planned maintenance or a forced outage; and
- Emergency – the unit is dispatched by the PJM system operator for emergency operation regardless of economic status.

In the modeling performed for this case, Dominion assumed that all of its dispatchable generation units, including its coal units, will be dispatched by the PJM system operator under *economic dispatch*.[4] However, in practice, Dominion has actually been dispatching its coal units through self-scheduling or designating the coal units as *must-run* for a significant number of dispatch hours.[5] There are numerous reasons why Dominion might designate its coal units as must-run. The two main reasons are: (i) to comply with testing requirements such as environmental requirements, permit requirements, and PJM requirements; and (ii) to avoid shutdown and startup costs during periods when the units are not economic and would not be dispatched by the PJM system operator.

Q8. PLEASE PROVIDE AN OVERVIEW OF HOW ECONOMIC DISPATCH WORKS IN PJM.

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[4] Direct Testimony of Jeffrey D. Matzen, *Petition of Virginia Electric and Power Company for reinstatement and revision of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2022-00070 (Jan. 24, 2023) at 2:6–11.

[5] Direct Testimony of Gregory L. Abbott – Public Version, *Application of Virginia Electric and Power Company to revise its fuel factor pursuant to Va. Code § 56-249.6*, Case No. PUR-2022-00064 (June 16, 2022) at 6-7. The percentage of MWhs generated under must-run conditions is lower than the percentage of hours because only the economic minimum number of MWs are designated as must-run.

A8. PJM defines economic dispatch as "the short-term determination by the PJM system operator of the optimal output of generation facilities, to meet the system load, at the lowest possible cost, subject to transmission and operational constraints."[6]

PJM has two energy markets for unit dispatch – the Day-Ahead energy market and the Real-Time energy market. Both of these energy markets match hourly energy price bids from energy generators with hourly energy demand from load serving entities ("LSEs"). Most energy transactions occur in the Day-Ahead energy market. However, the Day-Ahead hourly energy demand is a projection, and the amount of actual energy required can deviate from that projection in real-time. Such deviations are handled through energy transactions in the Real-Time energy market.[7]

A unit is considered to be "economic" in any given hour when its dispatch costs, or incremental variable costs, that are bid into the market are lower than the market-clearing hourly PJM energy price. PJM determines the hourly PJM energy price by stacking energy offers from generators based on bid price from lowest to highest. When there are enough MWs offered to satisfy the aggregate amount of energy required to serve the LSEs, the hourly equilibrium market price is determined. All generators that clear the market in a given hour receive the equilibrium market-clearing price for the energy generated rather than the specific price that the generator bid into the market for each unit. To the extent that the variable dispatch cost for a generating unit is lower than the hourly equilibrium

[6] PJM Glossary, https://pjm.com/en/Glossary. To the extent a generation unit is dispatched that includes a minimum run time of multiple hours with its bid, then economic dispatch of the unit means that the combined hourly energy prices over the minimum run time hours are greater than the unit's cumulative dispatch costs over those hours.

[7] The PJM Real-Time energy market also dispatches units on a sub-hourly (5-minute) basis to continuously match generation with system load.

market-clearing price, this produces economic profit margins for merchant generating plants and economic value to customers for vertically integrated utilities such as Dominion.

Q9. ARE PJM'S ENERGY MARKETS SUFFICIENTLY COMPETITIVE TO ALLOW RGGI TO OPERATE EFFICIENTLY AND AS INTENDED?

A9. Yes, in my opinion. The market structure as described above will yield a competitive market result, especially if the generation units are bid into the energy markets under an economic dispatch status. The inclusion of RGGI compliance costs into the hourly unit dispatch costs for fossil fuel units that are bid into the PJM energy markets will move those units higher up the economic dispatch stack and decrease the number of hours these units clear the market and are dispatched. However, any units that are self-scheduled by a utility under a must-run dispatch status in hours when the units are uneconomic,[8] and would not have otherwise been dispatched by the PJM system operator, can distort the market result.[9]

Q10. DID DOMINION REPRESENT THAT ITS GENERATION UNITS ARE DISPATCHED BY THE PJM SYSTEM OPERATOR ON AN ECONOMIC BASIS IN ITS LAST RIDER RGGI CASE?

A10. Yes. In fact, in Dominion's prior Rider RGGI case, the Hearing Examiner expressly stated his understanding that Dominion's "CO_2 regulated generation units are dispatched by PJM

[8] This occurs when the hourly unit dispatch cost is higher than the market clearing equilibrium price in the PJM energy market, resulting in the unit losing money on the must-run dispatch in that hour.

[9] It should be noted that it is a common practice to designate nuclear units as must-run units. This is to insure against the unlikely event that these units would not clear the PJM energy market in a given hour and be forced to shut down. However, nuclear units have extremely low variable operating costs, so almost all such hours of must-run dispatch are economic.

Additionally, it is occasionally necessary to designate fossil fuel generating units as must-run to perform environmental or reliability testing. Such dispatch is scheduled in advance and may or may not turn out to be economic. Any uneconomic must-run dispatch that is a result of scheduled testing requirements cannot be avoided.

based on *economic* dispatch."[10] His understanding was based on Dominion's express claims in that case that its units dispatch on an economic basis: "Actual CO_2 emissions, in turn, will be determined by how PJM . . . dispatches generators in the region. PJM dispatches generators *economically* based on the unit offer price, which includes the projected cost of Regional Greenhouse Gas Initiative ('RGGI') allowance purchases along with other costs, such as fuel."[11]

In the prior Rider RGGI case, Dominion did not disclose that it frequently self-schedules its coal units as must-run units.

Q11. WHY IS THE DISTINCTION BETWEEN ECONOMIC AND MUST-RUN DISPATCH IMPORTANT?

A11. When PJM dispatches a generation unit that is subject to RGGI on an economic basis, the dispatch cost, including the RGGI allowance cost, of running the unit is lower than the hourly PJM energy price.[12] Thus, the revenue received for the energy generated is sufficient to recover the cost of RGGI compliance.

However, when a coal generation unit is designated by its owner to be self-scheduled as must-run in a given hour, then the opposite may be true. Namely, the dispatch cost of running the coal unit could potentially be *higher* than the hourly PJM energy price and the resulting energy revenue received may not be sufficient to recover the costs of RGGI compliance. For a merchant fossil fuel plant, that company's shareholders would

[10] Report of D. Mathias Roussy, Jr., Hearing Examiner, *Virginia Electric and Power Company – for approval of rate adjustment clause, designated Rider RGGI, under section 55-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00169 (June 2, 2021) at 31 (emphasis added).

[11] Pre-filed Testimony of Dominion Witness George E. Hitch, *Virginia Electric and Power Company – for approval of rate adjustment clause, designated Rider RGGI, under section 55-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00169 (April 28, 2021) at 3 (emphasis added).

[12] This is true unless the unit is the marginal, or last, unit that clears the market, in which case its dispatch cost would be equal to the PJM energy price.

realize this loss including the costs of RGGI allowances. For a vertically integrated utility like Dominion, its captive customers bear the burden of this loss, and the RGGI allowance costs incurred during hours of uneconomic must-run dispatch flow to its customers through Rider RGGI.

Q12. WHAT ARE THE IMPLICATIONS OF THIS PRACTICE ON ACHIEVING THE RGGI POLICY GOALS?

A12. RGGI is a market mechanism designed to reduce both the amount of energy produced from fossil fuel generators and the associated tons of CO_2 emissions. However, in order for RGGI to operate efficiently and as intended, a competitive energy market is required. For merchant generators, the competitive operation of the PJM energy markets provides the market discipline of a competitive price signal to achieve this result. However, fossil fuel generating units owned by a vertically integrated utility like Dominion has captive customers who—subject to Commission approval—could bear those losses.

Given this dynamic, it may be incumbent on the Commission to intervene to ensure that Dominion's self-scheduling practices do not distort the competitive market resulting in customers paying unreasonable and unnecessary costs. It is Environmental Respondent's position that Dominion should not have a blank check to recover all RGGI costs from uneconomic must-run dispatch that was solely a result of Dominion management decisions that are contrary to the competitive market. Should Dominion be able to recover all such costs with impunity, not only would this subvert the policy goals of RGGI by unnecessarily increasing the tons of CO_2 emitted, it would also unnecessarily increase the costs of RGGI compliance borne by ratepayers.

PROJECTED VALUES VERSUS ACTUAL VALUES

Q13. PLEASE EXPLAIN WHY RACS, INCLUDING RIDER RGGI, ARE CALCULATED BASED ON PROJECTED VALUES?

A13. All RACs have two components: (1) a projected period that looks ahead to estimate costs based on forecasted modeling values and PLEXOS modeling results; and (2) a true-up period that looks back and corrects the prior projected period based on the values that actually occurred.

In the current case, Dominion is seeking to reinstate Rider RGGI to recover deferred RGGI compliance costs incurred after July 31, 2022, as well as compliance costs projected to occur over the period from September 1, 2023 through December 31, 2024. Thus, Dominion is seeking cost recovery in this case for the period from August 1, 2022 through December 31, 2024. However, Dominion assumes that Virginia will withdraw from RGGI on December 31, 2023 and has not included any RGGI-related compliance costs after that date. Thus, the relevant period of RGGI compliance costs at issue in this case is August 1, 2022 through December 31, 2023.

Q14. WHAT ARE SOME OF THE KEY VALUES AND MODELING ASSUMPTIONS USED IN THE CALCULATION OF RIDER RGGI?

A14. There are a number of assumptions that underpin the modeling performed for Rider RGGI. Some key assumptions relevant to Rider RGGI are listed below:

- Dominion used a projected CO_2 emission rate (tons of CO_2 per MWh) for each fossil fuel unit;

- Dominion assumed a weighted average price of $13.52 per allowance based on December ICE futures contracts for 2022 and 2023;[13] and
- Dominion assumed that all fossil fuel units only run if they are dispatched by the PJM system operator based on economic dispatch.

Q15. PLEASE EXPLAIN HOW DOMINION DETERMINES THE PROJECTED CO_2 EMISSION RATES TO USE IN ITS MODELING.

A15. Dominion's response to APV 5-6[14] states that each unit's applicable CO_2 emission rate is approved by PJM and the Market Monitor annually, and the same emission rate is used for all hours in which a unit is offered into PJM, regardless of the unit's dispatch status, for that year.

Q16. DO DOMINION'S FOSSIL FUEL UNITS ACTUALLY HAVE A CONSTANT EMISSION RATE FROM MONTH TO MONTH?

A16. No. I examined the actual emission rates for the period beginning on August 1, 2022 through January 31, 2023 and found that there was variability in the monthly emission rates for Dominion's coal units that are subject to RGGI over this historic period. Dominion's responses to APV 2-5 (a) and APV 2-5 (b) provided the actual monthly MWhs generated and tons of CO_2 emitted for each of its CO_2 emitting generating units.[15] From this data, I was able to calculate the actual monthly emission rate for each of Dominion's RGGI coal units displayed in the table below.

[13] Petition of Virginia Electric and Power Company for reinstatement and revision of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia, Case No. PUR-2022-00070 (Jan. 24, 2023) ("Petition") at 6.

[14] Attachment GLA-2.

[15] Attachment GLA-3.

Monthly CO_2 Tons / MWh

Unit	2022 Aug	Sep	Oct	Nov	Dec	2023 Jan
Chesterfield 5	1.1606	1.1486	n/a	1.0662	1.0566	1.1714
Chesterfield 6	1.1175	1.1077	n/a	1.0545	1.1176	n/a
Clover 1	1.2621	1.2378	n/a	n/a	1.1237	n/a
Clover 2	1.1634	n/a	n/a	n/a	1.0975	n/a
VCHEC	1.1581	1.4202	n/a	1.8298	1.1167	1.2896

Q17. DO YOU OBJECT TO DOMINION'S MODELING ASSUMPTION OF A CONSTANT EMISSION RATE OVER THE AUGUST 2022 THROUGH DECEMBER 2023 PERIOD?

A17. No. Even though actual emission rates vary from month to month, Dominion's current modeling assumption appears to be a reasonable proxy for modeling purposes. Also, the true-up will be based on actual CO_2 emissions over the period. So, even if there is some error in the projected emission rates, that error should be corrected in the subsequent true-up.

Q18. DO YOU HAVE ANY COMMENTS ON DOMINION'S RGGI ALLOWANCE PRICE ASSUMPTION USED IN ITS MODELING IN THIS CASE?

A18. Yes. Dominion assumed a weighted average price of $13.52 per allowance based on December ICE futures contracts for 2022 and 2023. Over the period August 1, 2022 through January 31, 2023, the actual average allowance price was $13.15.[16]

Q19. DO YOU OBJECT TO DOMINION'S RGGI ALLOWANCE PRICE ASSUMPTION USED IN ITS MODELING IN THIS CASE?

A19. No. Dominion's approach appears to be reasonable for modeling purposes. Further, any deviation from actual values should be corrected in the true-up. There is a disconnect,

[16] *See* Attachment GLA-3, Dominion response to APV 2-5 (d).

however, in how Dominion actually includes RGGI allowance costs in its hourly unit bids that it makes into the PJM energy markets and this modeling assumption.

Q20. PLEASE EXPLAIN THE DISCONNECT BETWEEN THE MODELING ASSUMPTION AND DOMINION'S ACTUAL BID PRACTICES.

A20. Dominion's modeling assumption is that a constant RGGI allowance price of $13.52 is included in the unit dispatch costs that are bid into the PJM energy markets. Dominion's response to APV 2-2[17] states that in actual practice the RGGI allowance price is imported daily from the ICE End of Day Report to determine the RGGI allowance price to be included in the unit bids into the PJM energy market. Thus, the allowance prices included in the hourly unit bids change daily in real time.

Q21. DOES DOMINION ACTUALLY PURCHASE RGGI ALLOWANCES IN REAL-TIME TO MATCH ITS ACTUAL BID PRACTICES?

A21. No. Dominion's response to APV 4-2[18] states that the ICE RGGI futures market does not have the liquidity to support a real-time purchase strategy.

Q22. DO YOU HAVE ANY COMMENTS ON THIS?

A22. I do not object to Dominion's use of the daily RGGI allowance price from the ICE End of Day Report in its modeling. However, these allowance prices will be different from the actual RGGI allowance costs incurred. The PJM energy market determines a market clearing energy price on an hourly basis. Each utility must bid its units into the market on a daily basis (24 hourly bids). In contrast, Dominion is allowed to comply with its RGGI allowance requirements over a three-year period with interim annual requirements of a minimum of 50% of allowances held. Dominion's response to APV 4-2 states that actual

[17] Attachment GLA-4.
[18] Attachment GLA-5.

RGGI allowance purchase prices are largely determined by the quarterly auction clearing prices.

Q23. PLEASE DISCUSS DOMINION'S MODELING ASSUMPTION THAT ALL FOSSIL FUEL UNITS ARE DISPATCHED BY THE PJM SYSTEM OPERATOR ON AN ECONOMIC BASIS.

A23. This is a simplifying assumption that Dominion makes in its modeling not only in this case but in all of the modeling performed by Dominion in support of Integrated Resource Plan filings, Renewable Portfolio Standard cases, Certificate of Public Convenience and Necessity cases for new generation units, and generation unit retirement analysis.

Q24. DOES THIS MODELING ASSUMPTION ACCURATELY REFELCT DOMINION'S ACTUAL UNIT DISPATCH PRACTICES?

A24. No. This assumption is particularly inaccurate for Dominion's coal units.

Q25. DID YOU INVESTIGATE THE ACTUAL HOURLY DISPATCH STATUS TO DATE OF DOMINION'S COAL UNITS OVER THE RELEVANT PERIOD?

A25. Yes, I investigated the actual dispatch for the period from August 1, 2022 through January 31, 2023. The table below shows the number of MWhs generated by each of Dominion's RGGI coal units over this period and the number of MWhs that were generated under a must-run dispatch status.

Must-Run Dispatch of Dominion's RGGI Coal Units
August 2022 through January 2023

Unit	Total MWhs	Must-Run MWhs	Must-Run MWhs Percent	Must-Run Less Testing MWhs	Must-Run Less Testing Percent	Must-Run Less Testing and Biomass Req. MWhs	Must-Run Less Testing and Biomass Req. Percent
Chesterfield 5	184,209	72,787	39.5%	19,542	10.6%	19,542	10.6%
Chesterfield 6	402,029	138,412	34.4%	62,432	15.5%	62,432	15.5%
Clover 1	112,238	40,216	35.8%	11,447	10.2%	11,447	10.2%
Clover 2	83,157	34,959	42.0%	3,227	3.9%	3,227	3.9%
VCHEC	482,152	174,717	36.2%	122,925	25.5%	35,375	7.3%
TOTAL	1,263,784	461,090	36.5%	219,574	17.4%	132,023	10.4%

Overall, 36.5% of the energy generated from these coal units was under a self-scheduled must-run dispatch status, ranging from 34.4% at Chesterfield unit 6 up to 42.0% at Clover unit 2. This is a fairly significant deviation from Dominion's modeling assumption of 100% economic dispatch.

One of the reasons for must-run dispatch status arises from the fact that these coal units are required to perform periodic testing. This testing is scheduled in advance and cannot be avoided. Dominion designates all such testing hours as must-run dispatch. Since testing is necessary, I think those must-run hours were reasonable and prudent. Removing all such must-run testing hours reduces the overall percentage of must-run MWhs to 17.4%, ranging from 3.9% at Clover unit 2 up to 25.5% at VCHEC.

Dominion's VCHEC unit is also subject to certain DEQ biomass permit requirements. The DEQ permit for VCHEC requires Dominion to average 10% of the fuel consumed at VCHEC, measured by heat content, to be biomass on a yearly basis.[19] In actual practice, the percentage of biomass consumed fluctuates above and below this 10% requirement. To the extent that VCHEC has consumed less than 10% from biomass from

[19] *See* Attachment GLA-6, DEQ Permit Number SWRO11526 at 13. The compliance year runs from July 1 to June 30.

an earlier period in the year, creating a biomass deficit, it appears that Dominion will make up for this deficit by consuming a higher percentage of biomass and designating such hours of dispatch as must-run to ensure that VCHEC actually is dispatched and the biomass gets consumed to meet VCHEC's 10% annual DEQ permit requirement. It is not clear whether the must-run hours necessary to meet the biomass requirements could have been avoided or not. Nevertheless, the table above also shows the number of MWhs removing both testing MWhs and DEQ permit requirement MWhs. Overall, this reduces the percentage of must-run MWhs to 10.4%, ranging from 3.9% at Clover unit 2 up to 15.5% at Chesterfield unit 6.

Q26. IS ALL MUST-RUN DISPATCH UNECONOMIC?

A26. No. There are a number of hours when must-run generation for Dominion's coal units have unit dispatch costs lower than the hourly PJM equilibrium market clearing price. In fact, for many of these hours, the coal unit would have been dispatched by the PJM system operator had Dominion instead decided to bid the units into the PJM energy market under economic dispatch. For the purposes of this case, I primarily focused on those must-run hours for Dominion's RGGI coal units that turned out to be uneconomic.

Q27. DOES THIS MEAN THAT YOU ARE UNCONCERNED WITH DOMINION'S GAS-FIRED GENERATION UNITS?

A27. No, not necessarily. I focused on Dominion's coal units in this case given that the operating characteristics of coal units put more pressure on Dominion to self-dispatch these units. In contrast, under current market conditions, Dominion's gas-fired units are more flexible with faster ramp times and have the ability to follow load fluctuations. This makes it less likely that these units will be self-scheduled by Dominion. Further, Dominion's gas units have lower CO_2 emission rates compared to the coal units. Therefore, the potential RGGI costs incurred during uneconomic must-run dispatch for the gas units are likely much lower than the coal units. Nonetheless, it may make sense to investigate the gas units in future proceedings.

<u>ANALYSIS OF UNECONOMIC MUST-RUN DISPATCH</u>

Q28. DID YOU ANALYZE THE RGGI COMPLIANCE COSTS INCURRED BY DOMINION'S COAL UNITS DURING THOSE HOURS OF OPERATION THAT WERE UNECONOMIC MUST-RUN DISPATCH?

A28. Yes. I examined hourly data provided by Dominion through discovery for the period August 1, 2022 through January 31, 2023. Thus, I examined 4,417 hours beginning with the hour ending 1 (1am) on August 1, 2022 through the hour ending 24 (12am) on January 31, 2023.

I was able to identify all hours of must-run dispatch for each coal unit and the MWhs generated that received the Day-Ahead energy market price and the number of MWhs that received the Real-Time energy market price. I was then able to compare the actual units' hourly dispatch costs to the corresponding Day-Ahead hourly LMP[20] prices and Real-Time hourly LMP prices. This allowed me to calculate whether each hour of must-run dispatch resulted in a net gain or a net loss. Those hours that resulted in a net loss are uneconomic. Therefore, the energy revenues received from selling the energy into the PJM energy markets in those hours were insufficient to recover the RGGI allowance costs incurred during those hours.

[20] "Locational Marginal Price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received." PJM Glossary, https://pjm.com/en/Glossary.

Q29. DID YOU CALCULATE THE AMOUNT OF RGGI COSTS INCURRED DURING THE HOURS OF UNECONOMIC MUST-RUN DISPATCH FOR EACH OF THE COAL UNITS?

A29. Yes. In performing this calculation, I used the actual monthly emission rate for each coal unit over the August 2022 through January 2023 period. Further, I used the actual average allowance price of $13.15 that Dominion incurred over this period.

Dominion owns a 50% share of Clover units 1 and 2 with the remaining 50% owned by ODEC. However, Dominion has operational control over the Clover units including all unit dispatch decisions. Dominion's response to APV 4-7[21] indicates that ODEC delivers allowances to Dominion's COATS account to cover ODEC's 50% ownership interest for the applicable control period or interim control period. Therefore, I adjusted the RGGI cost calculation for the Clover units by assuming that Dominion is only responsible for 50% of the costs.

The resultant cumulative cost of RGGI allowances for each coal unit for the uneconomic must-run dispatch hours over the August 2022 through January 2023 period is displayed below.

[21] Attachment GLA-7.

UNECONOMIC MUST-RUN DISPATCH RGGI COSTS
August 2022 through January 2023

	Uneconomic Must-Run Hours RGGI Cost	Uneconomic Must-Run Hours Less Testing Hours RGGI Cost	Uneconomic Must-Run Hours Less Testing and Biomass Req. Hours RGGI Cost
Chesterfield 5	($688,028)	($211,605)	($211,605)
Chesterfield 6	($1,312,353)	($749,573)	($749,573)
Clover 1	($278,567)	($81,424)	($81,424)
Clover 2	($205,119)	($23,290)	($23,290)
VCHEC	($2,547,807)	($1,669,516)	($217,417)
TOTAL	($5,031,875)	($2,735,408)	($1,283,308)

The first column in the table above shows that Dominion incurred a cumulative $5 million of RGGI costs over all uneconomic must-run dispatch hours during this period for these coal units. The second column shows that removing those uneconomic must-run hours that were required testing hours reduces the RGGI costs of self-scheduling to $2.7 million. The third column shows that further removing the must-run hours associated with meeting VCHEC's biomass permit requirement reduces the RGGI costs of self-scheduling to $1.3 million.

Q30. DID YOU CONSIDER AN ALTERNATIVE CALCULATION OF RGGI COSTS INCURRED DURING THE HOURS OF UNECONOMIC MUST-RUN DISPATCH?

A30. Yes. The analysis displayed in the table above depicts an hourly analysis examining each hour in isolation. In actual practice, Dominion makes bids on a daily basis, making 24 hourly bids in the Day-Ahead energy market and in the Real-Time energy market. Typically, Dominion will designate all 24 hours of a day as either economic dispatch or must-run dispatch, although occasionally it is a mix of economic and must-run.

Given this practice, I recalculated the RGGI costs depicted in the table above by making a daily adjustment. I examined each day that had any hours of uneconomic must-run dispatch and, if over the full 24 hours of the day there was a net daily gain, then I removed the RGGI costs for any uneconomic must-run hours for that day. In other words, the energy revenues received for that day's dispatch were sufficient to recover the RGGI costs for all 24 hours in the day including the uneconomic must-run dispatch hours. The results of this daily adjustment are shown in the table below.

UNECONOMIC MUST-RUN DISPATCH RGGI COSTS
With Daily Adjusment
August 2022 through January 2023

	Uneconomic Must-Run Hours RGGI Cost	Uneconomic Must-Run Hours Less Testing Hours RGGI Cost	Uneconomic Must-Run Hours Less Testing and Biomass Req. Hours RGGI Cost
Chesterfield 5	($644,594)	($168,171)	($168,171)
Chesterfield 6	($1,252,445)	($689,664)	($689,664)
Clover 1	($278,567)	($81,424)	($81,424)
Clover 2	($205,119)	($23,290)	($23,290)
VCHEC	($2,418,626)	($1,540,335)	($88,235)
TOTAL	($4,799,350)	($2,502,883)	($1,050,784)

The daily adjustment lowers the overall cumulative RGGI costs to $4.8 million for the uneconomic must-run dispatch hours for this period. The daily adjustment combined with removing those uneconomic must-run hours that were required testing hours reduces the RGGI costs of self-scheduling to $2.5 million. The daily adjustment combined with removing both the required testing hours and the must-run hours associated with meeting VCHEC's biomass permit requirement reduces the RGGI costs of self-scheduling to $1.1 million.

Q31. IS THE MUST-RUN DISPATCH ASSOCIATED WITH MEETING THE DEQ PERMIT REQUIREMENT BEYOND DOMINION'S CONTROL?

A31. It does not appear that the DEQ permit imposes any express requirement that Dominion designate VCHEC as a must-run unit. In fact, it appears that Dominion has control of the composition of the fuel consumed at VCHEC during a given period and that any need to dispatch VCHEC as must-run is driven by Dominion's decisions in earlier periods to consume less biomass than the 10% DEQ permit requirement.

Q32. CAN YOU POINT OUT ANY EVIDENCE OF THIS?

A32. Yes. In Dominion's 2022 Fuel Factor case, Case No. PUR-2022-00064, Dominion witness Vitiello provided oral testimony at the hearing that demonstrates that this is Dominion's practice. The relevant portion of the transcript is shown below.

> Q. So I first want to talk with you about Exhibit 19C, and this was Mr. Abbott's surrebuttal Exhibit 1, and this is presenting information on must-run days for VCHEC between January 27th and February 12th.
>
> And can you speak to what was happening with VCHEC during this time?
>
> A. Yes. All right. So between January 27th, 2021, and February 12th, 2021, stack testing was taking place at VCHEC so it would be must-run for testing. Also, **VCEHC has something called a biomass percentage requirement.** So in this 21 – it was actually the 20, slash, 21 period because it goes from July 1st to June 30th. **They needed a ten percent biomass requirement, and so on January 4th they were at 6.93 percent and they needed 48 additional days to reach that ten percent biomass requirement.** And that would be two boilers for 48 days. So we look at our monthly forwards, and usually January and February are going to be your highest LMPs because that's your winter periods and that's when gas prices are probably going to be highest.
>
> So if you're going to have your unit online for stack testing, then you're probably going to want keep running it to get your biomass percentage higher.
>
> **So then on February 15th, 2021, we reached 8.22 percent for our biomass percentage requirement, and we needed 29 more days**

> **to reach that ten percent.** But that's just an example of why you would see a must-run in that period and why you'd see it for that many days.[22]

Q33. WHAT COULD DOMINION DO DIFFERENTLY TO LOWER COMPLIANCE COSTS RELATED TO THE BIOMASS REQUIREMENT?

A33. Dominion should be proactively managing its biomass combustion at VCHEC to minimize the risk that the units will later have to be designated must-run for an extended period simply to meet the biomass permitting requirement. For example, Dominion could monitor its biomass deficit more closely and take corrective action to prevent the cumulative percentage of energy generated from biomass from falling below 9%.[23] And importantly, Dominion needs to document its decisions and provide such documentation and analysis to support the reasonableness and necessity of RGGI costs associated with uneconomic must-run dispatch to meet the VCHEC biomass permitting requirement.

Q34. WHAT ARE YOUR RECOMMENDATIONS BASED ON YOUR ANALYSIS OF THE UNECONOMIC MUST-RUN DISPATCH FOR DOMINION'S COAL UNITS?

A34. For the period August 2022 through January 2023, I recommend, at a minimum, that the RGGI costs incurred during the uneconomic must-run hours that were not required for testing or to meet the DEQ biomass permit requirement at VCHEC be disallowed as unnecessary RGGI compliance costs. I further recommend that this calculation be based on the daily adjustment described above. This recommendation results in the disallowance of $1.1 million of RGGI compliance costs as unnecessary. Based on the evidence in this

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[22] Hearing Transcript, *Application of Virginia Electric and Power Company to revise its fuel factor pursuant to Va. Code § 56-249.6*, Case No. PUR-2022-00064 (July 7, 2022) at 285:3-286:10 (Cross Examination of Company Witness Vitiello on Rebuttal) (emphasis added).

[23] It does not appear that Dominion has made any changes in its fuel burn strategy at VCHEC in response to the imposition of RGGI compliance costs.

case, I do not believe that Dominion has established that these costs are necessary or reasonable and prudent.

In addition, I believe the Commission has the discretion to also disallow RGGI costs associated with uneconomic must-run dispatch at VCHEC to meet the DEQ biomass permit requirement. Should the Commission find that these RGGI compliance costs are not necessary or reasonable and prudent, this would increase the disallowance of RGGI compliance costs from $1.1 million to $2.5 million for the period August 2022 through January 2023.

I further recommend that Dominion perform a similar analysis in future Rider RGGI true-up proceedings to determine any unnecessary RGGI compliance costs that are incurred after January 2023.

As to the biomass issue, I further recommend that the Commission require Dominion to document its must-run decisions at VCHEC based on the biomass permitting requirements and provide that information in future proceedings. I believe the Commission needs this information in order to analyze whether the related costs are reasonable and prudent.

Q35. DOES THIS CONCLUDE YOUR TESTIMONY?

A35. Yes.

Attachment GLA-1

Gregory Abbott Testimonies/Reports

Proceeding	Case/Docket No.	On Behalf of:
Dale Service Corporation For General Increase in Rates	Virginia SCC Case No. PUE-2001-00200	Virginia SCC Staff
CPV Cunningham Creek LLC For Approval of a Generation Certificate	Virginia SCC Case No. PUE-2001-00477	Virginia SCC Staff
CPV Warren LLC For Approval of a Generation Certificate	Virginia SCC Case No. PUE-2002-00075	Virginia SCC Staff
Dale Service Corporation For Review of Changes to Terms and Conditions	Virginia SCC Case No. PUE-2002-00092	Virginia SCC Staff
Virginia Natural Gas, Inc. For Approval of a Weather Normalization Adjustment Rider	Virginia SCC Case No. PUE-2002-00237	Virginia SCC Staff
Virginia-American Water Company For General Increase in Rates	Virginia SCC Case No. PUE-2002-00375	Virginia SCC Staff
Community Electric Cooperative For Approval of Retail Access Tariffs and Terms and Conditions of Service for Retail Access	Virginia SCC Case No. PUE-2003-00007	Virginia SCC Staff
A&N Electric Cooperative For Review of Tariffs and Terms and Conditions of Service for Retail Service	Virginia SCC Case No. PUE-2003-00279	Virginia SCC Staff
Central Virginia Electric Cooperative For Approval of Its Plan to Implement Retail Access	Virginia SCC Case No. PUE-2003-00327	Virginia SCC Staff
Atmos Energy Corporation For an Increase in Rates	Virginia SCC Case No. PUE-2003-00507	Virginia SCC Staff
Virginia-American Water Company For General Increase in Rates	Virginia SCC Case No. PUE-2003-00539	Virginia SCC Staff
Washington Gas Light Company For Approval of an Experimental Weather Normalization Adjustment	Virginia SCC Case No. PUE-2001-00010	Virginia SCC Staff
Craig-Botetourt Electric Cooperative For a General Increase in Electric Rates	Virginia SCC Case No. PUE-2005-00012	Virginia SCC Staff
Virginia Natural Gas, Inc. For Approval of a Performance Based Rate Regulation Methodology	Virginia SCC Case No. PUE-2005-00057	Virginia SCC Staff

Virginia Natural Gas, Inc. For Investigation of Justness and Reasonableness of Current Rates, Charges, and Terms and Conditions of Service	Virginia SCC Case No. PUE-2005-00062	Virginia SCC Staff
Roanoke Gas Company For and Expedited Increase in Rates	Virginia SCC Case. No. PUE-2005-00075	Virginia SCC Staff
Highland New Wind Development, LLC For Approval to Construct, Own and Operate an Electric Generation Facility	Virginia SCC Case. No. PUE-2005-00101	Virginia SCC Staff
Dale Service Corporation For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2006-00070	Virginia SCC Staff
Virginia Natural Gas, Inc. For Approval of an Experimental Weather Normalization Adjustment for General Service Customers	Virginia SCC Case. No. PUE-2006-00095	Virginia SCC Staff
Roanoke Gas Company For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2006-00099	Virginia SCC Staff
CPV Warren, LLC For Approval of a Generation Certificate	Virginia SCC Case. No. PUE-2007-00018	Virginia SCC Staff
Appalachian Power Company For Adjustment to Capped Electric Rates	Virginia SCC Case. No. PUE-2007-00069	Virginia SCC Staff
Old Dominion Electric Coop. & Columbia Gas of Virginia For Approval of a Certificate to Acquire Ownership Interest	Virginia SCC Case. No. PUE-2007-00088	Virginia SCC Staff
James River Cogeneration Company For a Certificate to Operate as an Electric Generating Facility	Virginia SCC Case. No. PUE-2007-00092	Virginia SCC Staff
Spectra Energy Virginia Pipeline Co. For Cancellation of Certificates	Virginia SCC Case. No. PUE-2007-00106	Virginia SCC Staff
Appalachian Power Company For Approval to Participate in the Virginia Renewable Energy Portfolio Standard Program	Virginia SCC Case. No. PUE-2008-00003	Virginia SCC Staff
Atmos Energy Corporation For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2008-00007	Virginia SCC Staff
Virginia Electric and Power Company For Approval of a Generation Certificate	Virginia SCC Case. No. PUE-2008-00014	Virginia SCC Staff
Columbia Gas of Virginia, Inc. For Approval of an Experimental Weather Normalization Adjustment Mechanism	Virginia SCC Case. No. PUE-2008-00074	Virginia SCC Staff

Roanoke Gas Company For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2008-00088	Virginia SCC Staff
Mecklenburg Electric Cooperative For a General Increase in Electric Rates	Virginia SCC Case. No. PUE-2009-00006	Virginia SCC Staff
Virginia Electric and Power Company For Approval of Annual Filing of Rider S	Virginia SCC Case. No. PUE-2000-00011	Virginia SCC Staff
Virginia Electric and Power Company For Approval of a Rate Adjustment Clause for Recovery of the Costs of the Bear Garden Generating Station	Virginia SCC Case. No. PUE-2009-00017	Virginia SCC Staff
Washington Gas Light Company For Approval of Natural Gas Conservation and Ratemaking Efficiency Plan including a Decoupling Mechanism	Virginia SCC Case. No. PUE-2009-00064	Virginia SCC Staff
Craig-Botetourt Electric Cooperative For a General Increase in Electric Rates	Virginia SCC Case. No. PUE-2009-00065	Virginia SCC Staff
Appalachian Power Company For Approval of Purchase Power Agreements as Part of Its Participation in the Virginia Energy Portfolio Standard Program	Virginia SCC Case. No. PUE-2009-00102	Virginia SCC Staff
Columbia Gas of Virginia, Inc. For Authority to Increase Rates and Charges and to Revise the Terms and Conditions	Virginia SCC Case. No. PUE-2010-00017	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Continue Two Rate Adjustment Clauses, Riders C1 and C2	Virginia SCC Case. No. PUE-2010-00084	Virginia SCC Staff
Appalachian Power Company Proposed Pilot Programs on Dynamic Rate Structures for Renewable Generation Facilities	Virginia SCC Case. No. PUE-2010-00134	Virginia SCC Staff
Virginia Natural Gas, Inc. For an Increase in Base Rates and Authority to Revise the Terms and Conditions	Virginia SCC Case. No. PUE-2010-00142	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Establish an Electric Vehicle Pilot Program	Virginia SCC Case. No. PUE-2011-00014	Virginia SCC Staff
Appalachian Power Company For Approval of a Rate Adjustment Clause, RPS-RAC, to Recover the Incremental Costs of Participation in the Virginia Renewable Energy Portfolio Standard Program	Virginia SCC Case. No. PUE-2010-00034	Virginia SCC Staff

Virginia Electric and Power Company For Approval to Implement New Demand-Side Management Programs and For Approval of Two Updated Rate Adjustment Clauses	Virginia SCC Case. No. PUE-2011-00093	Virginia SCC Staff
Virginia-American Water Company For a General Increase in Rates	Virginia SCC Case. No. PUE-2011-00127	Virginia SCC Staff
Virginia Electric and Power Company To Revise a Rate Adjustment Clause: Rider R	Virginia SCC Case. No. PUE-2012-00068	Virginia SCC Staff
Virginia Electric and Power Company For Revision of Rate Adjustment Clause: Rider B	Virginia SCC Case. No. PUE-2012-00072	Virginia SCC Staff
Appalachian Power Company For Approval of the Recovery of Incremental Costs of Participation in the Renewable Energy Portfolio Program	Virginia SCC Case. No. PUE-2012-00094	Virginia SCC Staff
Virginia Electric and Power Company For Approval & Certification of Proposed Brunswick Co. Power Station	Virginia SCC Case. No. PUE-2012-00128	Virginia SCC Staff
Atmos Energy Corporation For Approval of a Special Contract for Gas Transportation Service	Virginia SCC Case. No. PUE-2013-00038	Virginia SCC Staff
Northern Virginia Electric Cooperative For Approval of Pole Attachment Rates and Terms and Conditions	Virginia SCC Case. No. PUE-2013-00055	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUE-2013-00088	Virginia SCC Staff
Virginia Electric and Power Company For Revision of Rate Adjustment Clause: Rider BW	Virginia SCC Case. No. PUE-2013-00122	Virginia SCC Staff
Appalachian Power Company Petition for Approval of Rat Adjustment Clause	Virginia SCC Case. No. PUE-2014-00007	Virginia SCC Staff
Appalachian Power Company Application for a 2014 Biennial Review of the Rates, Terms and Conditions for the Provision of Generation, Distribution and Transmission Services	Virginia SCC Case. No. PUE-2014-00026	Virginia SCC Staff
Virginia Electric and Power Company For Establishment of a Rate Adjustment Clause: Rider U, New Underground Distribution Facilities	Virginia SCC Case. No. PUE-2014-00089	Virginia SCC Staff
Appalachian Power Company Petition for Approval of Rate Adjustment Clause Related to its Participation in the Renewable Portfolio Energy Portfolio Program	Virginia SCC Case. No. PUE-2015-00034	Virginia SCC Staff

Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUE-2015-00035	Virginia SCC Staff
Washington Gas Light Company Application for Approval of a Natural Gas Supply Investment Plan	Virginia SCC Case. No. PUE-2015-00055	Virginia SCC Staff
Virginia Electric and Power Company For Approval of Special Rates, Terms and Conditions	Virginia SCC Case. No. PUE-2015-00103	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Establish Experimental Companion Rates Designated Rate Schedule MBR - GS-3 and Rate Schedule MBR - GS-4	Virginia SCC Case. No. PUE-2015-00108	Virginia SCC Staff
Virginia Electric and Power Company For Establishment of a Rate Adjustment Clause: Rider U, New Underground Distribution Facilities	Virginia SCC Case. No. PUE-2015-00114	Virginia SCC Staff
Atmos Energy Corporation Application for Expedited Approval of a Special Contract for Gas Transportation Service	Virginia SCC Case. No. PUE-2015-00125	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUE-2016-00049	Virginia SCC Staff
Virginia Electric and Power Company For Revision of a Rate Adjustment Clause: Rider U	Virginia SCC Case. No. PUE-2016-00136	Virginia SCC Staff
Appalachian Power Company For Approval of a Wind G Rate Adjustment Clause	Virginia SCC Case. No. PUR-2017-00031	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUR-2017-00051	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Establish Experimental Companion Tariff, Designated Schedule RF	Virginia SCC Case. No. PUR-2017-00137	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUR-2018-00065	Virginia SCC Staff
Virginia Electric and Power Company For Approval of a Rate Adjustment Clause, Designated Rider E	Virginia SCC Case. No. PUR-2018-00195	Virginia SCC Staff
Virginia Electric and Power Company For Approval & Certification of Proposed US-3 Solar Projects and for Approval of a Rate Adjustment Clause, Designated Rider US-3	Virginia SCC Case. No. PUR-2018-00101	Virginia SCC Staff

Virginia Electric And Power Company For Prudency Determination with Respect to the Coastal Virginia Offshore Wind Project	Virginia SCC Case. No. PUR-2018-00121	Virginia SCC Staff
Virginia Electric And Power Company For Revision of Rate Adjustment Clause: Rider US-3	Virginia SCC Case. No. PUR-2019-00104	Virginia SCC Staff
Virginia Electric And Power Company For Approval & Certification of Proposed US-4 Solar Projects and for Approval of a Rate Adjustment Clause, Designated Rider US-4	Virginia SCC Case. No. PUR-2019-00105	Virginia SCC Staff
Virginia Electric And Power Company For a Prudency Determination with Respect to the Westmoreland Solar Power Purchase Agreement	Virginia SCC Case. No. PUR-2019-00133	Virginia SCC Staff
Virginia Electric And Power Company Integrated Resource Plan	Virginia SCC Case. No. PUR-2020-00035	Virginia SCC Staff
Virginia Electric And Power Company Establishing 2020 RPS Proceeding	Virginia SCC Case. No. PUR-2020-00134	Virginia SCC Staff
Appalachian Power Company Establishing 2020 RPS Proceeding	Virginia SCC Case. No. PUR-2020-00135	Virginia SCC Staff
Virginia Electric And Power Company Allocating RPS Costs to Certain Customers of Virginia Electric And Power Company	Virginia SCC Case. No. PUR-2020-00164	Virginia SCC Staff
Virginia Electric And Power Company To Revise Its Fuel Factor	Virginia SCC Case. No. PUR-2022-00064	Appalachian Voices
Appalachian Power Company 2022 Integrated Resource Plan Filing	Virginia SCC Case. No. PUR-2022-00051	Appalachian Voices
Roanoke Gas Company For an Expedited Rate Increase	Virginia SCC Case. No. PUR-2022-00205	Roanoke Gas Company
Virginia Electric And Power Company For Approval of its 2022 RPS Development Plan	Virginia SCC Case. No. PUR-2022-00124	Appalachian Voices

Attachment GLA-2

Virginia Electric and Power Company
Case No. PUR-2022-00070
Appalachian Voices
Fifth Set

The following response to Question No. 6 of the Fifth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on February 24, 2023, was prepared by or under the supervision of:

Wesley A. Hudson
Manager – Electric Market Operations
Virginia Electric and Power Company

Question No. 6

Please reference Dominion's response to APV 2-2. Does the applicable CO2 emission rate for VCHEC change in a given hour based on the relative percentage of biomass versus coal consumed in that hour? Is the applicable CO2 emission rate for VCHEC different in those hours that Dominion has self-scheduled VCHEC as a must run unit to meet its DEQ biomass permit requirements?

Response:

A unit's applicable CO2 emission rate is approved by PJM and the Market Monitor annually, and the same emission rate is used for all hours in which a unit is offered into PJM, regardless of the unit's dispatch status, for that year. While the percentage of biomass fuel may range from 0-10% during a given hour, that does not impact the applicable CO2 emission rate in the Company's offer.

Attachment GLA-3

Virginia Electric and Power Company
Case No. PUR-2022-00070
Appalachian Voices
Second Set

As it pertains to subpart (a), the following response to Question No. 5 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on February 7, 2023, was prepared by or under the supervision of:

Wesley A. Hudson
Manager – Electric Market Operations
Virginia Electric and Power Company

As it pertains to subparts (b) through (d), the following response to Question No. 5 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on February 7, 2023, was prepared by or under the supervision of:

George E. Hitch
Senior Market Originator
Virginia Electric and Power Company

Question No. 5

For the period August 1, 2022 through January 31, 2023, please provide the following actual information for each of Dominion's carbon emitting generating units subject to RGGI (e.g. Brunswick, Bear Garden, VCHEC, Clover, etc.):

a) The actual MWhs generated each month;

b) The actual number of short tons of CO2 emissions generated each month;

c) The actual number of allowances required each month;

d) The actual total cost of RGGI allowances each month.

Response:

a) See Attachment APV Set 02-05(a) (WAH).

b) See Attachment APV 02-05(b) (GEH).

c) RGGI does not have monthly allowance requirements. Regulated emissions sources must acquire CO2 allowances equal to their CO2 emissions over each three-year RGGI control period, as well as the interim control periods, at the end of each of the first two calendar years of the control period. In the RGGI CO2 Allowance Tracking

System, allowances can only be assigned to a generating unit for a specific "Allocation Year."

d) Because the allowances are tracked by "Allocation Year," the Company cannot calculate monthly RGGI allowance costs by generating unit. However, the weighted average price of all allowances purchased for total RGGI emissions during the period August 1, 2022 through January 31, 2023 is $13.15.

Attachment APV Set 02-05(a) (WAH)

Actual Net MWhs Generated by the Company's Carbon Emitting Generating Units Subject to RGGI

	2022					2023
Unit	Aug	Sep	Oct	Nov	Dec	Jan
Bear Garden	217,499	351,177	252,158	281,676	258,408	251,464
Brunswick County	941,605	928,067	862,992	88,777	453,906	932,910
Chesapeake GT1	135	119	0	5	763	0
Chesapeake GT6S	119	0	0	5	297	0
Chesterfield 5	51,653	15,973	0	42,653	70,842	3,088
Chesterfield 6	151,623	53,516	0	96,748	100,142	0
Chesterfield 7	55,741	57,622	1	0	113,671	140,807
Chesterfield 8	82,037	92,079	17,955	105,250	108,228	139,541
Clover 1	29,527	17,239	0	0	65,472	0
Clover 2	32,728	0	0	0	50,429	0
Darbytown CT1	872	61	0	484	4,763	1,665
Darbytown CT2	927	0	0	207	5,816	0
Darbytown CT3	925	0	0	181	6,202	0
Darbytown CT4	909	0	0	512	8,881	238
Elizabeth River CT1	1,773	466	0	0	4,886	0
Elizabeth River CT2	1,185	4,531	10,818	0	4,973	0
Elizabeth River CT3	1,172	459	0	0	5,355	0
Gravel Neck CT3	752	0	2,627	0	4,240	0
Gravel Neck CT4	309	0	0	0	4,141	0
Gravel Neck CT5	1,029	0	2,753	0	270	0
Gravel Neck CT6	1,398	0	487	0	287	0
Gravel Neck GTS	3	0	0	0	1,076	15
Greensville County	1,133,539	302,970	1,031,742	1,096,711	1,051,606	1,122,768
Ladysmith CT1	36,312	16,322	0	0	8,565	0
Ladysmith CT2	17,291	4,521	0	9,476	20,949	4,759
Ladysmith CT3	36,195	18,190	35,785	15,122	7,239	0
Ladysmith CT4	30,526	28,222	26,192	25,798	8,748	0
Ladysmith CT5	32,548	29,171	19,012	3,700	6,383	0
Lowmoor CT1	81	0	0	0	487	0
Lowmoor CT2	80	0	0	0	499	0
Lowmoor CT3	1	0	0	0	442	0
Lowmoor CT4	2	0	0	0	459	0
Northern Neck CT1	211	0	0	0	556	40
Northern Neck CT2	171	0	0	0	627	170
Northern Neck CT3	0	0	0	35	505	67
Northern Neck CT4	150	0	0	0	526	0
Possum Point 6	308,500	87,116	0	17,134	172,701	143,013
Possum Point GTS	1,744	0	0	0	263	32
Remington CT1	31,917	23,107	15,975	15,556	21,554	3,674
Remington CT2	25,142	17,897	12,141	8,057	7,200	0
Remington CT3	34,628	24,795	8,579	20,716	21,410	4,164
Remington CT4	25,477	17,372	3,188	7,844	6,162	385
South Anna 1	67,010	22,509	78,904	57,747	71,241	53,764
South Anna 2	67,568	52,221	0	48,433	70,547	60,733
Warren County	929,851	885,897	264,666	835,907	884,959	733,372
Yorktown 3	0	0	0	0	0	0
Virginia City Hybrid Energy Center	175,727	7,627	0	2,413	165,574	130,811

Monthly CO_2 Tons - RGGI

Plant	UnitNum	August	September	October	November	December
BEARGRDN	1A	45,193.5	73,336.4	50,565.0	60,611.4	52,698.4
BEARGRDN	1B	50,328.4	72,655.3	54,221.5	55,325.3	56,891.7
BRUNSWCK	1A	131,897.8	129,314.4	128,109.0	12,097.9	64,428.9
BRUNSWCK	1B	131,700.8	129,088.7	116,800.7	12,204.1	82,908.5
BRUNSWCK	1C	132,162.8	129,819.1	113,978.9	12,010.1	46,541.2
CHESTFLD	5	59,946.4	18,346.6	0.0	45,478.7	74,851.2
CHESTFLD	6	169,442.2	59,281.5	0.0	102,018.4	111,916.9
CHESTFLD	7	26,677.3	27,885.1	0.0	0.0	51,052.4
CHESTFLD	8	38,407.1	43,883.1	8,302.8	47,860.6	49,191.7
CLOVER	1	37,267.9	21,337.9	0.0	0.0	73,573.6
CLOVER	2	38,076.9	0.0	0.0	0.0	55,348.0
DARBY GT	1	936.2	31.2	0.0	338.8	4,877.7
DARBY GT	2	987.1	0.0	0.0	165.3	5,660.3
DARBY GT	3	995.8	0.0	0.0	119.6	5,967.3
DARBY GT	4	973.1	0.0	0.0	456.4	7,949.3
ELIZRIVR	1	1,585.7	501.8	0.0	0.0	4,865.6
ELIZRIVR	2	1,286.6	3,676.4	7,837.5	0.0	4,921.0
ELIZRIVR	3	1,266.6	494.4	0.0	0.0	5,309.9
GORDON	1	33,625.8	11,319.9	37,944.2	27,882.7	36,636.3
GORDON	2	33,881.7	25,983.3	0.0	24,259.4	37,325.7
GRAVL GT	3	704.9	0.0	1,956.7	0.0	4,449.9
GRAVL GT	4	332.3	0.0	0.0	0.0	4,366.6
GRAVL GT	5	889.3	0.0	2,037.3	0.0	156.2
GRAVL GT	6	1,182.9	0.0	357.6	0.0	280.8
GREENSVIL	1A	147,972.7	42,043.8	135,522.8	138,987.5	132,951.7
GREENSVIL	1B	144,472.9	40,985.6	131,728.0	135,844.1	130,095.4
GREENSVIL	1C	146,874.0	34,183.1	129,843.6	138,764.7	132,370.0
LADYSMTH	1	22,475.8	10,081.0	0.0	0.0	7,572.2
LADYSMTH	2	10,833.3	2,715.8	0.0	6,094.4	14,443.1
LADYSMTH	3	22,463.3	11,062.5	21,746.2	9,000.2	5,915.8
LADYSMTH	4	18,454.6	17,210.1	16,006.1	15,336.4	7,713.5
LADYSMTH	5	19,786.9	17,620.7	11,565.9	2,302.5	5,574.1
POSSUM	6A	68,701.2	15,924.0	0.0	2,629.1	35,283.6
POSSUM	6B	67,495.6	21,985.9	0.0	5,586.9	43,561.2
REMINGTN	1	18,628.7	13,436.4	9,306.3	8,926.0	14,304.4
REMINGTN	2	15,730.8	11,077.7	7,453.3	4,896.6	6,429.3
REMINGTN	3	21,619.0	15,255.4	5,427.9	12,610.3	15,061.3
REMINGTN	4	15,963.2	10,869.3	1,953.6	4,760.3	5,470.0
VA CITY	1	67,002.1	7,371.2	0.0	0.0	100,415.1
VA CITY	2	136,509.5	3,459.7	0.0	4,414.6	84,485.2
WARREN	1A	126,803.4	120,798.0	37,172.3	115,489.5	118,704.9
WARREN	1B	126,223.0	120,018.3	37,154.8	114,791.0	118,078.3
WARREN	1C	125,722.3	119,705.1	34,413.0	113,313.2	117,353.2
YORKTWN	3	0.0	623.3	0.0	238.6	2,317.5

Attachment GLA-4

Virginia Electric and Power Company
Case No. PUR-2022-00070
Appalachian Voices
Second Set

The following response to Question No. 2 of the Second Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on February 7, 2023, was prepared by or under the supervision of:

Wesley A. Hudson
Manager – Electric Market Operations
Virginia Electric and Power Company

Question No. 2

Please provide a narrative description of how Dominion determines the RGGI allowance costs that are included in the hourly unit dispatch costs that are bid into the PJM energy markets for each of its carbon emitting generating units subject to RGGI.

Response:

The RGGI allowance price is imported daily from the ICE futures End of Day Report. This price is then multiplied by each applicable unit's CO2 emission rate to calculate the additional RGGI dispatch cost. See the equation below as an example.

$$\frac{\$(RGGI\ Price)}{Ton} \times \frac{(CO_2\ Rate)\ Ton}{MWh} = \frac{\$(RGGI\ Cost)}{MWh}$$

Attachment GLA-5

Virginia Electric and Power Company
Case No. PUR-2022-00070
Appalachian Voices
Fourth Set

The following response to Question No. 2 of the Fourth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on February 21, 2023, was prepared by or under the supervision of:

George E. Hitch
Senior Market Originator
Virginia Electric and Power Company

Question No. 2

Dominion's response to APV 2-2 indicates that Dominion uses the RGGI allowance price from the ICE futures end of day report to calculate each unit's additional RGGI dispatch costs included in Dominion's hourly unit bids into the PJM energy markets.

a) Does Dominion attempt to purchase RGGI allowances in real-time at the daily ICE futures prices to match each unit's actual dispatch?

b) If not, please explain how Dominion actually purchases its RGGI allowances and how the actual RGGI allowance purchase prices may differ from the RGGI allowance prices included in each unit's hourly dispatch costs bid into PJM's energy markets.

Response:

a) No. The ICE RGGI futures market does not have the liquidity to support a real-time purchase strategy.

b) Please see page 6 of the Direct Testimony of Company Witness George Hitch. Actual RGGI allowance purchase prices are largely determined by the quarterly auction clearing prices. Dispatch allowances prices are based on daily ICE futures settlement prices, which reflect more current market consensus on the supply of and demand for allowances.

Attachment GLA-6

more piles. The DEQ shall not require through this approval process, the use of more waste coal than would otherwise be burned in the facility.
(9VAC5-80-490 and Condition 22 of 5/2/14 PSD Permit)

14. Fuel Burning Equipment Requirements - After the first 36 months of commercial operation, the company shall use at least 5 percent biomass per year. Starting in the fifth year of commercial operation, the company shall increase the use of biomass by an additional 1 percent per year up to no less than 10 percent per year thereafter. For purposes of such biomass requirement, the percent shall be determined by the total biomass heat input for any given year divided by the total heat input for any given year averaged over a rolling three years.

    Should market conditions indicate that biomass fuel has a significant ratepayer impact or promotes tree cutting, such biomass requirement shall be reduced or eliminated until market conditions correct. Dominion shall retain an independent consultant to advise with such matters and shall obtain approvals for the elimination or reduction of the practice from DEQ.
    (9VAC5-80-490 and Condition 24 of 5/2/14 PSD Permit)

15. Fuel Burning Equipment Requirements - The throughput of coal, coal refuse and coke-derived solid fuel to each CFB boiler (CFB1 & CFB2) shall not exceed 1,760,760 tons per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
    (9VAC5-80-490 and Condition 10 of 6/26/14 MACT Permit)

16. Fuel Burning Equipment Requirements - The throughput of wood/bark to each CFB boiler (CFB1 & CFB2) shall not exceed 685,000 tons per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
    (9VAC5-80-490, Condition 25 of 5/2/14 PSD Permit and Condition 11 of 6/26/14 MACT Permit)

17. Fuel Burning Equipment Requirements - The approved fuels for the emergency generator engine (EDG) and fire pump engine (EFP) are distillate oil and diesel fuel. The distillate oil shall meet the ASTM D396 specification for numbers 1 or 2 fuel oil except that the maximum sulfur content shall not exceed 0.0015 percent by weight per shipment. The diesel fuel shall meet the ASTM D975 specification for numbers 1-D S15 or 2-D S15 diesel fuel. A change in the fuels may require a permit to modify and operate.
    (9VAC5-80-490, 40 CFR 60.4207(b) and Condition 26 of 5/2/14 PSD Permit)

Attachment GLA-7

Virginia Electric and Power Company
Case No. PUR-2022-00070
Appalachian Voices
Fourth Set

The following response to Question No. 7 of the Fourth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on February 21, 2023, was prepared by or under the supervision of:

George E. Hitch
Senior Market Originator
Virginia Electric and Power Company

Question No. 7

Please describe how the RGGI compliance costs for Clover units 1 and 2 are determined and shared between Dominion and ODEC. For example, does Dominion procure the required RGGI allowances and assign 50% of the costs to ODEC? Or is ODEC responsible for procuring the required RGGI allowances for their share of carbon emissions?

Response:

ODEC delivers allowances to the Company's COATS account to cover ODEC's 50% ownership interest share of the total CO2 allowances required for Clover units 1 and 2 for the applicable control period or interim control period. ODEC is solely responsible for how and when it acquires any CO2 allowances, and any associated costs.