COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

PETITION OF

VIRGINIA ELECTRIC AND POWER COMPANY CASE NO. PUR-2022-00070

For reinstatement and revision of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia

REPORT OF M. RENAE CARTER, HEARING EXAMINER

June 1, 2023

This case concerns the reinstatement of Dominion's Rider RGGI rate adjustment clause at a revised rate to recover deferred and projected costs Dominion has incurred, and expects to incur, over the period August 1, 2022, through December 31, 2023. Dominion and Staff agree upon a revised revenue requirement of approximately $356.6 million, to be recovered over the Rate Year September 1, 2023, through August 31, 2024. Appalachian Voices seeks five adjustments to Rider RGGI: to account for certain times the Company self-scheduled its coal units to run in PJM resulting in a net economic loss in a 24-hour period (two potential adjustments); to update forecasted data with actuals for January through March 2023 to account for an over-forecast of the number of CO_2 allowances Dominion projects it will need to comply with RGGI; and to remove two errors related to the number of allowances Dominion projected it would need involving the Clover facility and three biomass facilities. Among other things, I recommend the Commission reject, as bases for revising the Rider RGGI revenue requirement, the proposed adjustments related to self-scheduled unit dispatch and concern with over-forecasting. I recommend that adjustments for the Clover- and biomass-related errors be made, and I direct Dominion to make a compliance filing as part of its comments to this Report, including adjusted Rider RGGI rates and accompanying workpapers correcting these errors.

HISTORY OF THE CASE

This case concerns Virginia Electric and Power Company's ("Dominion" or "Company") Rider RGGI, a rider designed to recover Dominion's costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI"), a market-based trading program for carbon dioxide emissions. The State Corporation Commission ("Commission") originally approved Rider RGGI in Case No. PUR-2020-00169, allowing Dominion to recover projected allowance costs of $167,759,000 for the period ending July 31, 2022, subject to true-up.[1]

---

[1] *Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2020-00169, 2021 S.C.C. Ann. Rep. 273, Order Approving Rate Adjustment Clause (Aug. 4, 2021) ("*Initial Rider RGGI Final Order*"), *upheld*, 2021 S.C.C. Ann. Rep. 279, Order on Reconsideration (Nov. 17, 2021), *aff'd*, __ Va. __, 879 S.E.2d 35 (Va. Sup. Ct. 2022). The rider approved in that case will be referred to herein as the "Initial Rider RGGI" and the case generally as the "Initial Rider RGGI Case."

On May 5, 2022, Dominion filed a request that the Commission suspend Rider RGGI effective July 1, 2022. The Commission granted this request on June 15, 2022, ordering Rider RGGI to be suspended and the Rider RGGI Projected Cost Recovery Factor to be reset to $0.00/kilowatt-hour ("kWh"), effective July 1, 2022. The Commission also approved Dominion's request to recover, through both Rider RGGI and the Company's base rates (subject to further review in a Rider RGGI actual cost true-up proceeding and in the Company's 2024 Triennial Review), the Company's RGGI compliance costs incurred through July 31, 2022.[2]

On December 14, 2022, Dominion filed a Petition wherein it seeks Commission approval to: (i) account for the allowance costs the Company incurred and recovered through the Initial Rider RGGI prior to its suspension on July 1, 2022; and (ii) reinstate Rider RGGI to recover deferred costs incurred after July 31, 2022, and costs the Company projects it will incur over the period September 1, 2023, through August 31, 2024 ("Rate Year"). For purposes of the Petition, Dominion assumed that Virginia will exit RGGI on December 31, 2023, and thus the Company did not project it would incur RGGI-related compliance costs after that time.[3] Specifically, the Company asked to collect, over the Rate Year, a Virginia-jurisdictional revenue requirement of $373,214,000 to cover Rider RGGI costs incurred, or to be incurred, over the period August 1, 2022, through December 31, 2023.[4] Dominion asserted that for the period January 1, 2021, through July 31, 2022, the Virginia jurisdictional revenue requirement for RGGI-related costs was approximately $267 million, and that the Company recovered approximately $84 million of this amount through the Initial Rider RGGI during the collection period that ran January 1, 2022, through June 30, 2022. Dominion stated that it will recover the difference, approximately $183 million, through its base rates in effect as incurred.[5]

On January 24, 2023, the Commission issued its Order for Notice and Hearing in this case, which, among other things, provided the opportunity for interested persons to file comments on the Petition or to participate in this matter as respondents; directed Commission Staff ("Staff") to investigate the Petition and file testimony thereon; scheduled a public hearing on the Petition to occur May 1 and 4, 2023; and appointed a Hearing Examiner to conduct all further proceedings in this matter.

On February 14, 2023, Dominion filed a Motion for Entry of a Protective Ruling, and a Hearing Examiner's Protective Ruling was issued on February 16, 2023.

On March 9, 2023, Dominion filed proof of notice and service.[6]

---

[2] *Petition of Virginia Electric and Power Company, For authority to suspend a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia, and for alternate recovery mechanism of certain compliance costs*, Case No. PUR-2022-00070, Doc. Con. Cen. No. 220630078, Order Granting Petition at 3-4 (June 15, 2022) ("*Rider RGGI Suspension Order*").

[3] Exhibit No. 2 (Petition) at 5.

[4] *Id.* at 5-7.

[5] *Id.* at 6.

[6] *See* Exhibit No. 1.

The following filed Notices of Participation in this case by March 7, 2023: Appalachian Voices ("APV") and the Virginia Committee for Fair Utility Rates ("Committee").[7] On March 8, 2023, the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel") filed a Notice of Participation along with a Motion for Leave to File Notice of Participation Out of Time; the latter was granted by Hearing Examiner's Ruling dated March 10, 2023.

Three written public comments were received in this case:

- **Tony Giddens** stated that Dominion is constantly adjusting its rates. Mr. Giddens believes the Company is attempting to keep its profits high and suggests that if high profits are a legitimate need, perhaps executives could take a cut in their salaries.

- **Lisa Fraser** stated that she is already paying almost $30 per month in rider fees, which she cannot afford. She also stated the riders "have nothing to do with" power usage in the western portion of Virginia. She suggested that utility companies take money for special projects out of their profits instead of asking consumers to pay for them.

- **Ceres**, a nonprofit organization, stated its support for Virginia remaining in RGGI, and urged the Commission to consider whether Dominion could recover some or all of the Rider RGGI costs through current base rates, with no impact on customers' bills. In the event the Commission approves Rider RGGI, Ceres agreed with APV witness Abbott that the Commission should investigate Dominion's dispatch of coal generating units, particularly with regard to bidding the units into the PJM Interconnection, L.L.C. ("PJM") market under "must-run" status. Ceres also recommended that the Commission oversee Dominion's management of its fossil fleet, consistent with a recent decision the Commission made concerning Appalachian Power Company.[8] Ceres urged the Commission to require Dominion to log: all hours in which the Company placed coal units in "must run" status; those units' operating costs; the PJM market clearing prices during the hours the units ran in must-run status; and the Company's reasons for using must-run status for those units at those times. Ceres stated that this log should be provided to the Commission and the public at least once a year.

No one registered to speak as a public witness in this proceeding; as a result, the May 1, 2023 portion of the hearing was not convened. The evidentiary portion of the hearing was convened on May 4, 2023, in the Commission's courtroom. The following attorneys appeared: Elaine S. Ryan, Esquire, Timothy D. Patterson, Esquire, Nicole M. Allaband, Esquire,

---

[7] According to the Committee's Notice of Participation, its members are Dominion customers who have a substantial interest in the rates Dominion charges, and they will be directly affected by the outcome of this proceeding. Notice of Participation of the Virginia Committee for Fair Utility Rates at 1, 3.

[8] *Petition of Appalachian Power Company, For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2022-00001, Doc. Con. Cen. No. 221130019, Final Order at 2-3 (Nov. 21, 2022).

Paul E. Pfeffer, Esquire, and Lisa R. Crabtree, Esquire, for the Company; Nathaniel Benforado, Esquire, and E. Grayson Holmes, Esquire, for APV; Christian F. Tucker, Esquire, for the Committee;[9] C. Mitch Burton Jr., Esquire, for Consumer Counsel; and Frederick D. Ochsenhirt, Esquire, for Staff.

SUMMARY OF THE RECORD

Dominion – Direct

In support of its Petition, Dominion offered the direct testimonies of **George E. Hitch**, Senior Market Originator for the Company; **Jeffrey D. Matzen**, Manager of Integrated Strategic Planning; **Paul M. McLeod**, Director – Regulatory Accounting for the Company; and **C. Alan Givens**, Manager – Regulation Rate Design for the Company.

Company witness **George E. Hitch** first provided background on RGGI, describing it as a collaborative effort by 11 Northeast and Mid-Atlantic States to reduce carbon dioxide (CO_2) emissions from the energy sector. Mr. Hitch reported that because Virginia joined RGGI in 2021 and the Company owns RGGI-regulated sources of emissions, the Company must obtain and surrender a CO_2 emission allowance for each short ton of CO_2 emitted by those sources. For purposes of this filing, Mr. Hitch noted that the Commonwealth is planning to withdraw from RGGI by the end of 2023. Thus, the Company has projected that no new RGGI-related compliance costs would be incurred beyond that date.[10] The exception would be for any allowances that Dominion may need to purchase in early 2024 to cover actual fourth quarter 2023 emissions that surpass the Company's projections for that period.[11]

According to Mr. Hitch, RGGI requires regulated emission sources to acquire CO_2 allowances to cover emissions in each three-year control period. The current control period covers calendar years 2021, 2022, and 2023. In addition, RGGI requires regulated sources to hold at least half of their allowances for Years 1 and 2 of the control period in their source compliance accounts.[12] If a generator does not have enough surrendered allowances to cover CO_2 emissions during the three-year control period, the generator must then surrender three additional allowances per ton of excess emissions.[13]

Mr. Hitch stated that allowances can be obtained through quarterly RGGI auctions or secondary markets. The RGGI CO_2 Allowance Tracking System tracks and records the allowances.[14] Mr. Hitch reported that quarterly auction volume increased with the March 1, 2020 auction when New Jersey first participated in the quarterly auctions, and again starting in March 2021 when Virginia first participated in the auctions. He also showed how

---

[9] The Committee attended and monitored the hearing but did not offer an opening or closing statement or cross-examine witnesses.

[10] Exhibit No. 3 (Hitch Direct) at 2-3.

[11] *Id.* at 7-8.

[12] *Id.* at 3.

[13] *Id.* at 8.

[14] *Id.* at 3.

allowance prices have been a moving target, from a low of $2.53/short ton in 2017 to a high of $13.96/short ton in 2022.[15]

Specific to Dominion, Mr. Hitch indicated that the Company would need approximately 59.7 million allowances by the end of the current control period. In this Petition, the Company is seeking cost recovery for approximately 31 million allowances to cover the period August 1, 2022, through December 31, 2023. Mr. Hitch also reported that Dominion met the 2021 interim control period requirement and averred that, based on 2022 year-to-date emissions, Dominion expects that it will meet the 2022 interim control period requirement with the allowances in its account.[16]

Mr. Hitch explained that the Company's RGGI compliance approach is auction-based, not price-based. That is, the Company purchases approximately ¼ of the allowances it needs through each RGGI quarterly auction and fills any allowance deficiencies through secondary market purchases. Mr. Hitch affirmed that Dominion's practice is not to build a large inventory bank but, instead, to purchase allowances to cover emissions that have already been made by the Company's facilities.[17]

Mr. Hitch summarized that, as of November 18, 2022, Dominion has purchased almost 32 million allowances with a weighted average price of $11.58 per allowance.[18] For purposes of determining the requested revenue requirement in this case, Mr. Hitch reported that Dominion assumed a weighted average price of $13.52 per allowance, based on December Intercontinental Exchange, Inc. ("ICE"), futures contracts for 2022 and 2023.[19]

During the hearing, Mr. Hitch testified that Dominion purchased 3.9 million allowances in RGGI's March allowance auction, less than the 5.367117 million the Company estimated, at the time it prepared the Petition, that the Company would purchase.[20] He stated that factors impacting how many allowances the Company needed to purchase were the mild winter weather in early 2022, secondary market purchases, carryover of unneeded allowances from 2022, and the delivery of some allowances from Old Dominion Electric Cooperative ("ODEC").[21]

Mr. Hitch co-sponsored Filing Schedule 46A with Company witness Matzen. This schedule provides actual and projected costs associated with Rider RGGI and accompanying documentation.

Company witness **Jeffrey D. Matzen** supports the CO_2 emissions forecast and the CO_2 allowance price forecast.

---

[15] *Id.* at 4-5.
[16] *Id.* at 5-6.
[17] *Id.* at 6-7.
[18] *Id.* at 7.
[19] *Id.* at 8.
[20] Tr. at 56-57 (Hitch).
[21] *Id.* at 58-59 (Hitch).

Mr. Matzen first described how the Company used the PLEXOS® modeling software to simulate units' economic dispatch and then pulled the estimated CO_2 emission production from each Virginia-located resource (*i.e.*, excluding the Company's Mt. Storm and Rosemary facilities). He explained that PLEXOS accounts for the cost of RGGI participation by adding the forecasted cost of CO_2 allowances to each Virginia generating unit subject to RGGI. Where these units are dispatched less by the model, PLEXOS supplies market purchases.[22]

Mr. Matzen estimated Dominion will need approximately 31 million CO_2 allowances to cover emissions over the period August 1, 2022, through December 31, 2023.[23] He stated that the projected CO_2 allowance prices used in PLEXOS were $12.92/allowance for October through December 2022, and $13.66 for each month in 2023.[24] These figures result in a simple average price of $13.51 per allowance, or $13.52 per allowance when weighted by volume, for the October 2022 through December 2023 period.[25] Mr. Matzen explained that Dominion developed these prices using 15 months of forward market prices from ICE, a widely used exchange for multiple commodities.[26]

During the hearing, Mr. Matzen testified about the Clover facility, which is co-owned by Dominion and ODEC, and for which Dominion and ODEC each supply 50% of the allowances needed to offset emissions. Mr. Matzen explained that Dominion models Clover in PLEXOS at half its size to estimate its half of emissions from that facility.[27] He also clarified that the Company's load forecast assumes normal weather and that the mild weather in early 2023 caused both the Company's load requirements and commodity prices to trend lower than normal.[28]

Mr. Matzen co-sponsored Filing Schedule 46A with Company witness Hitch. This schedule provides actual and projected costs associated with Rider RGGI and accompanying documentation.

Exhibit 1: Dominion Energy Virginia's RGGI Compliance and RPS Development Plan Modeling. Mr. Matzen also sponsored Petition Exhibit 1 ("Compliance Report"), which analyzes how Dominion's RGGI compliance corresponds to the Company's annual renewable energy portfolio standard ("RPS") Plan filings required by Code § 56-585.5.[29] According to the Compliance Report, the annual RPS Plan filings must outline how Dominion intends to meet the

---

[22] Exhibit No. 9 (Matzen Direct) at 2-3.
[23] *Id.* at 2.
[24] *Id.* at Schedule 1.
[25] *Id.* at 4.
[26] *Id.* at 3; Tr. at 75 (Matzen).
[27] Tr. at 69-70 (Matzen).
[28] *Id.* at 73-74 (Matzen).
[29] The Company states it provided the Compliance Report to comply with a requirement in the *Initial Rider RGGI Final Order*. Therein, the Commission wrote that it "recognizes that Dominion's RGGI compliance is not isolated from its RPS plans, which are also required by statute. . .. [W]e herein direct the Company to include in future Rider RGGI filings an analysis of how its RGGI compliance corresponds to its RPS plan filings." 2021 S.C.C. Ann. Rep. at 276.

renewable generation and energy storage development targets of the Virginia Clean Economy Act ("VCEA").[30]

According to the Compliance Report, Dominion's latest RPS Development Plan ("2022 RPS Plan") was filed on October 14, 2022, in Case No. PUR-2022-00124.[31] Dominion averred that its 2022 RPS Plan is consistent with what is labeled as Alternative Plan B in the Company's latest Integrated Resource Plan ("IRP") update filed on September 1, 2022.[32] The Company described IRP Alternative Plan B as compliant with the VCEA's RPS development targets. Specifically, the Company claimed that the 2022 RPS Plan will support reductions in CO_2 emissions in Virginia through development of more carbon-free generating facilities, which will take the place of market purchases and output from Company-owned generating facilities that emit CO_2 as a combustion byproduct.[33]

To explain how its Rider RGGI Petition corresponds to its 2022 RPS Plan, the Company stated that, to determine the forward RGGI allowance requirements for the Petition, it "projected CO_2 emissions by modeling system dispatch using assumptions that are generally consistent with" the latest IRP update and with the 2022 RPS Plan.[34] These assumptions include updated load and commodity price forecasts and the same assumption of a 22.5% capacity factor for existing and future solar resources. The Company noted that, in Rider RGGI modeling, it adjusted the assumption of when Virginia would exit RGGI from the end of 2022 (used in the latest IRP update and the 2022 RPS Plan) to the end of 2023. The Company explained that though this revision affects the dispatch of generating units in 2023, it does not affect the Company's plans for developing solar, onshore wind, and energy storage.[35]

Additionally, the Compliance Report explained that the Company models dispatch of its fleet in the PJM energy market using PLEXOS software. Specifically, PLEXOS treats RGGI compliance costs the same way it treats fuel costs, so the model will dispatch a Dominion-owned

---

[30] Exhibit No. 2 (Petition) Ex. 1 at 1. (This Report uses "Ex." to identify attachments to documents that the filer labeled as "Exhibits.") The VCEA was enacted by 2020 Va. Acts chs. 1193, 1194.

[31] Exhibit No. 2 (Petition) Ex. 1 at 1. *See generally, Petition of Virginia Electric and Power Company, For approval of its 2022 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia and related requests*, Case No. PUR-2022-00124.

[32] Exhibit No. 2 (Petition) Ex. 1 at 1. The Commission has ruled on the Company's latest IRP. *See Commonwealth of Virginia, ex rel. State Corporation Commission, In. re: Virginia Electric and Power Company's 2022 Update to its Integrated Resource Plan pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2022-00147, Doc. Con. Cen. No. 221050184, Final Order (Oct. 31, 2022) (wherein, at pages 1-2, the Commission found the Company's filing to be "legally sufficient" pursuant to the Commission's IRP Guidelines but noted that "[s]uch acceptance, . . ., does not 'express approval . . . of the magnitude or specifics of Dominion's future spending plans, the costs of which will significantly impact millions of residential and business customers in the monthly bills they must pay for power.'").

[33] Exhibit No. 2 (Petition) Ex. 1 at 3-4.

[34] *Id.* at 4.

[35] *Id.* at 4-5.

carbon-emitting generating unit when the compliance cost of RGGI in addition to other variable costs (such as fuel) are lower than the cost of a market purchase. Dominion asserted that in following the 2022 RPS Plan and including RGGI-related costs in dispatch decisions, Dominion's RGGI compliance modeling and its 2022 RPS Plan modeling correlate.[36]

Company witness **Paul M. McLeod** discussed the Rate Year revenue requirement and summarized how Dominion has recovered and will recover all RGGI-related compliance costs from January 1, 2021, through the end of December 2023.[37]

Mr. McLeod provided an overview of how RGGI allowances are treated for accounting purposes. He stated all CO_2 allowances that are purchased are tracked as one intangible asset. He explained that as CO_2 is emitted each month from Dominion's generating units, this asset is amortized based on the then-present weighted-average cost per allowance. Depending on the timing of allowance auctions and the purchase dates of allowances, Dominion may carry on its books an intangible asset representing the allowances purchased but not yet used. At other times, Dominion may be "short" on allowances, in which case Dominion records on its books a reduction to rate base in the Rider RGGI revenue requirement.[38]

Mr. McLeod explained the history of Rider RGGI, noting that Initial Rider RGGI was implemented starting January 1, 2022, and ran through June 30, 2022, at which point it was suspended.[39] Total RGGI-related costs through July 31, 2022, on a Virginia jurisdictional basis, were $267 million, $84 million of which was recovered through Initial Rider RGGI. Mr. McLeod stated that Dominion is recovering the remainder, $183 million, through base rates in effect as incurred.[40] He explained that the reinstated Rider RGGI is designed to cover the RGGI costs incurred during the period August 1, 2022, through the end of 2023, approximately $373 million, as illustrated in the following diagram:[41]

Period Incurred	Amount	Recovery Mechanism	Recovery Period
Jan. 1, 2021 – July 31, 2022	$267M	$84M – Initial Rider RGGI	Jan. 1 – June 30, 2022
		$183M – Base rates	As incurred[42]
Aug. 1, 2022 – Dec. 31, 2023	$373M	$373M – Rider RGGI	Sept. 1, 2023 – Aug. 31, 2024
		Any true-up for calendar year 2022 – Rider RGGI update	Sept. 1, 2024 – Aug. 31, 2025
Total All Periods	$640M		

[36] *Id.*
[37] Exhibit No. 12 (McLeod Direct) at 1-2.
[38] *Id.* at 4.
[39] *Id.* at 2-3.
[40] *Id.* at 3-5 and Appendix B.
[41] *Id.* at 3-6.
[42] Per Mr. McLeod, this recovery will be reviewed by the Commission as part of Dominion's next base rate case. Exhibit No. 12 (McLeod Direct) at 5.

Mr. McLeod noted that the Company is using the 9.35% return on equity ("ROE") set in Dominion's most recent Triennial Review for the Rider RGGI revenue requirement calculations after the date of the Final Order in that case, which was November 18, 2021.[43] He stated that the calculation of the revenue requirement in this Petition also is based on the capital structure methodology approved by the Commission in the *2021 Triennial Order*.[44] For Rider RGGI calculations pertaining to the pre-November 18, 2021 time period, Dominion has used the 9.2% ROE approved by the Commission in Case No. PUR-2019-00050.[45]

Mr. McLeod next described the major components of the revenue requirement: the Projected Cost Recovery Factor and the Actual Cost True-Up Factor. He explained that the Projected Cost Recovery Factor is the revenue requirement needed to recover (i) the Company's amortization expense for CO_2 allowances; (ii) projected financing costs on purchased but unamortized CO_2 allowance balances; and (iii) amortization of deferred costs (including financing costs) that were incurred prior to the Rate Year.[46] Mr. McLeod stated that the revenue requirement contains $0 for the Actual Cost True-Up Factor since the Company plans to recover the difference between costs incurred and dollars recovered through Rider RGGI through July 31, 2022, in base rates.[47] He noted that the Company expects to make a 2023 Rider RGGI filing, with a rate year of September 1, 2024, through August 31, 2025, to the extent any calendar year 2022 true-up is necessary.[48] He later updated this statement to note that Dominion may not make a true-up filing for 2022 until 2024 since the Company may not have enough data for a 2023 filing.[49] He also explained that the Company used the 2021 year-end cost of capital and year-end capital structure to develop the rates proposed in this case.[50]

Mr. McLeod stated that the revenue requirement calculations in this Petition are consistent with those approved by the Commission in the *Initial Rider RGGI Final Order* with a few exceptions. First, the Company is proposing to modify the allocation factor calculation

[43] Exhibit No. 12 (McLeod Direct) at 5. *See also Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rep. 444, 445-446, Final Order (Nov. 18, 2021) ("*2021 Triennial Order*").

[44] Exhibit No. 12 (McLeod Direct) at 5. *See also 2021 Triennial Order*, 2021 S.C.C. Ann. Rep. at 445-446.

[45] Exhibit No. 12 (McLeod Direct) at 5. *See also Application of Virginia Electric and Power Company, For the determination of the fair rate of return on common equity pursuant to § 56-585.1:1 C of the Code of Virginia*, Case No. PUR-2019-00050, 2019 S.C.C. Ann. Rep. 400, Final Order (Nov. 21, 2019).

[46] Exhibit No. 12 (McLeod Direct) at 6, 7.

[47] *Id.* at 6. *See also Rider RGGI Suspension Order* at 4 ("RGGI compliance costs that are incurred up through July 31, 2022 (and ultimately approved by the Commission), and which have not been recovered prior to the suspension of the Rider, may be recovered through the utility's base rates for generation services in effect during the period incurred.").

[48] Exhibit No. 12 (McLeod Direct) at 6.

[49] Tr. at 100-101 (McLeod).

[50] Exhibit No. 12 (McLeod Direct) at 6 and Schedule 1, pp. 16-17.

methodology: (i) to calculate allocation factors monthly instead of annually; and (ii) to remove the North Carolina jurisdiction from the allocation basis. Further, Dominion is using an updated revenue lag based on calendar year 2021 data in certain cash working capital calculations in this case, which the Commission approved in another Dominion case.[51]

Mr. McLeod described the composition of the rate base in his Schedule 1, stating that rate base includes month-end unamortized purchased CO_2 allowance balances (or short position), unrecovered deferred costs, and cash working capital.[52] He further stated that any RGGI-related indirect costs (such as broker fees) would be recovered through the Company's base rates.[53] He concluded that through this Petition Dominion is seeking recovery of a total revenue requirement of $373,214,000.[54]

During the hearing, Mr. McLeod testified that a cell in a spreadsheet erroneously caused the Company to count both its and ODEC's shares of allowances related to emissions at the Clover facility, as allowances for which Dominion is responsible.[55] This error occurred in relation to actual data since 2021 only, not projected data.[56] He estimated that correcting for this error would result in a small change to the revenue requirement, approximately 2% to 3% of allowances in total.[57]

Mr. McLeod sponsored Filing Schedules 3, 3A, 4, 5 and 8, which provide information on Dominion's cost of capital. He also sponsored Filing Schedule 46B, Statements 1 and 2. These provide annual revenue requirement information for proposed Rider RGGI.

Company witness **C. Alan Givens** described the cost allocation methodology for Rider RGGI. He explained that Dominion is obligated to produce energy to meet customers' energy requirements, and the dispatch and output of Dominion generating facilities that emit CO_2 drive the need to purchase CO_2 allowances. Mr. Givens asserted that, accordingly, allocating Dominion's costs for participating in RGGI to jurisdictions and to customer classes on an energy basis is reasonable. He noted that the Commission approved this methodology in the *Initial Rider RGGI Final Order*.[58]

Mr. Givens then explained a change to the Rider RGGI cost allocation caused by the decision of the North Carolina Utilities Commission that Dominion cannot recover RGGI costs

---

[51] *Id.* at 8. *See also Petition of Virginia Electric and Power Company, For approval of new broadband capacity projects pursuant to § 56-585.1:9 of the Code of Virginia and for revision of rate adjustment clause: Rider RBB for the Rate Year commencing December 1, 2022*, Case No. PUR-2022-00062, Doc. Con. Cen. No. 221050174, Final Order (Oct. 31, 2022).
[52] Exhibit No. 12 (McLeod Direct) at 8 and Schedule 1, pp. 3-14.
[53] *Id.* at 9.
[54] *Id.*
[55] Tr. at 88-89 (McLeod).
[56] *Id.* at 89-90 (McLeod).
[57] *Id.* at 90-93 (McLeod).
[58] Exhibit No. 14 (Givens Direct) at 2-3. *See also Initial Rider RGGI Final Order*, 2021 S.C.C. Ann. Rep. at 273-274, 277.

from its North Carolina customers.[59] Mr. Givens stated that Dominion now must remove usage associated with its North Carolina customers from the allocation basis. Accordingly, he developed monthly factors to allocate the costs of RGGI compliance only to the Virginia jurisdiction.[60] He developed actual monthly allocation factors, based on actual energy usage, for January 2021 through September 2022, by dividing Virginia jurisdiction megawatt-hour ("MWh") sales by system MWh sales, and excluding sales to North Carolina customers.[61] He made a similar calculation for the October 2022 through August 2024 period based on forecasted usage and forecasted MWh sales.[62]

Mr. Givens explained the Company's proposed Rider RGGI rate design, which uses a uniform per-kWh charge for each customer in Dominion's Virginia jurisdiction taking generation service from the Company. He testified this is the same rate design methodology approved by the Commission in the *Initial Rider RGGI Final Order*.[63] Using Company witness McLeod's estimated Virginia jurisdiction revenue requirement and total estimated Virginia jurisdictional sales for the Rate Year, Mr. Givens calculated a proposed Rider RGGI cost recovery rate of $0.004642/kWh.[64]

Mr. Givens provided the proposed Rider RGGI tariff sheet, which identifies the Rider RGGI rate applicable to each Dominion rate schedule.[65] He also provided typical bill comparisons for customers on various rate schedules at representative consumption levels based on proposed Rider RGGI.[66] He calculated that the monthly bill of a residential customer using 1,000 kWh/month of electricity would increase by approximately $4.64.[67] Mr. Givens' calculations reflected that only two riders (Rider OSW and the Company's fuel rider) take up a higher portion of such a customer's bills.[68]

Mr. Givens sponsored Filing Schedule 46C, Statements 1 and 2. These address Dominion's methodology for allocating the Rider RGGI revenue requirement among rate classes and the design of a uniform rate.

---

[59] Exhibit No. 14 (Givens Direct) at 3. *See also In the Matter of Petition of Dominion Energy North Carolina for a Declaratory Ruling*, Docket No. E-22, Sub 601, Order on Petition for Declaratory Ruling (N.C.U.C. Sept. 29, 2021).
[60] Exhibit No. 14 (Givens Direct) at 3. The North Carolina decision was made after the *Initial Rider RGGI Final Order*, which was issued in August 2021.
[61] Exhibit No. 14 (Givens Direct) at 3 and Schedule 1, p. 1.
[62] *Id.* at 3-4 and Schedule 1, p. 2.
[63] *Id.* at 4. *See also Initial Rider RGGI Final Order*, 2021 S.C.C. Ann. Rep. at 273-274, 277.
[64] Exhibit No. 14 (Givens Direct) at 4 and Schedule 2.
[65] *Id.* at 4 and Schedule 3.
[66] *Id.* at 4-5 and Schedule 4.
[67] *Id.* at 5 and Schedule 4.
[68] *Id.* at Schedule 4.

Appalachian Voices

APV offered the testimony of **Gregory Abbott**. He described RGGI and how the program, through market signals, encourages fossil-fueled generating facilities to lower their CO_2 emissions.[69]

Mr. Abbott discussed trends in energy markets over approximately the past decade. He asserted that during this interval, coal-fired units have gone from serving as baseload units to intermediate resources, which may create economic challenges, due to these units' high start-up costs, as well as operational challenges, because these units perform best when run at a steady state creating a relatively constant level of output.[70]

Mr. Abbott then discussed the ways generator units can be offered into the PJM energy market, focusing on the "economic dispatch" and "must-run" options.[71] He observed that to the extent a generator bids a lower price for any given hour than the PJM equilibrium price for that hour, the generator obtains economic value for running its plant, assuming the generator bid the unit into the market at a price that covers its dispatch costs (including RGGI compliance costs). Mr. Abbott explained that calculating a unit's dispatch costs to include RGGI compliance costs will make those units more expensive to run, meaning they "beat" the economic dispatch equilibrium price less often and thus run less often under economic dispatch.[72]

Mr. Abbott also described an alternative scenario, must-run dispatch, in which the unit operator self-schedules the unit to run at a particular output level no matter whether or not it would have been selected to run under economic dispatch.[73] In such a case, the cost to run a generating unit may be higher than the equilibrium price that PJM pays, meaning the operator would not bring in enough money for that hour to cover the cost of running the plant.[74] Mr. Abbott asserted that in Dominion's situation, "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."[75] According to Mr. Abbott, RGGI only works as intended in a competitive market for energy.[76]

Mr. Abbott expressed concern over Dominion's modeling for this case, which assumed economic dispatch of all its generating units, compared to Dominion's practice of scheduling its coal units as "must-run" over "a significant number of dispatch hours."[77] He calculated the following percentages of must-run activity for Dominion's coal fleet from August 2022 through January 2023, noting specific must-run activity at Dominion's Virginia City Hybrid Energy

---

[69] Exhibit No. 16 (Abbott Direct) at 2-3.
[70] *Id.* at 4-5.
[71] *Id.* at 5-6.
[72] *Id.* at 7-8.
[73] *Id.* at 6, 8.
[74] *Id.* at 9.
[75] *Id.* at 10.
[76] *Id.*
[77] *Id.* at 6. *See also id.* at 15.

Center ("VCHEC") apparently related to compliance with that facility's Department of Environmental Quality ("DEQ") biomass permit:[78]

- Total energy production of coal fleet as must-run: 36.5%
- Total excluding testing hours: 17.4%
- Total excluding testing hours and VCHEC Biomass hours: 10.4%

Mr. Abbott admitted that not all hours of must-run operation are uneconomic; there are times when the market would have selected a must-run unit to run under economic dispatch conditions.[79] To focus on uneconomic-only must-run dispatch, Mr. Abbott compared the PJM day-ahead and real-time hourly locational marginal prices ("LMP") to Dominion's coal units' hourly dispatch costs, noting when must-run dispatch costs exceeded LMP (*i.e.*, where the Company experienced a net loss for running that unit in that hour).[80] He calculated RGGI costs incurred during times of uneconomic dispatch between August 2022 and January 2023, using a \$13.15 CO_2 allowance price (the actual cost per allowance that Dominion incurred during this period) and the monthly emission rate of each coal unit.[81] Mr. Abbott then made a "daily" adjustment, since Dominion must designate each hourly bid in the PJM day-ahead and real-time markets the same (either 24 hourly economic bids, or 24 hourly must-run bids). His results were as follows:

Total RGGI Costs by type	Uneconomic Dispatch Costs[82]	Uneconomic Dispatch Costs with Daily Adjustment[83]
All uneconomic must-run hours	\$5,031,875	\$4,782,248
All uneconomic must-run hours minus testing hours	\$2,735,408	\$2,485,781
All uneconomic must-run hours minus testing hours and VCHEC biomass hours	\$1,283,308	\$1,033,681

Mr. Abbott calculated there were 11 days when Dominion ran its facilities under must-run conditions with negative daily margins.[84] He noted that four of the uneconomic days were associated with times PJM had issued a weather-related alert or advisory. He stated that

[78] *Id.* at 16-17 ("To the extent that VCHEC has consumed less than 10% from biomass from 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.")
[79] *Id.* at 17.
[80] *Id.* at 18.
[81] *Id.* at 19.
[82] *Id.* at 20.
[83] *Id.* at 21; Exhibit No. 15 (ER-PE-10) (showing corrections to the table, "Uneconomic Must-Run Dispatch RGGI Cost With Daily Adjustment August 2022 through January 2023").
[84] Tr. at 132 (Abbott).

such an upcoming event does not require a coal generating facility to be run days in advance.[85] He also testified that, from August 2022 through January 2023, VCHEC ran a total of 541 hours, and 540 of these were uneconomic must-run dispatch hours, an amount he considered "excessive."[86]

Mr. Abbott opined that the must-run hours for VCHEC's biomass requirement are within Dominion's control, and "any need to dispatch VCHEC as must-run is driven by Dominion's decisions in earlier periods to consume less biomass" than needed to comply with its DEQ permit.[87] He suggested that Dominion more closely watch its biomass deficit "to prevent the cumulative percentage of energy generated from biomass from falling below 9%," that Dominion document decisions related to biomass use, and that Dominion provide this "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."[88]

Given the inconsistency between modeling and operations, Mr. Abbott suggested the Commission may need "to intervene to ensure that Dominion's self-scheduling practices do not distort the competitive market resulting in customers paying unreasonable and unnecessary costs."[89] He claimed that ratepayers should not have to pay RGGI costs for decisions made by Dominion's management that do not comport with a competitive market.[90] Specifically, Mr. Abbott recommended the Commission disallow approximately $1.0 million in RGGI compliance costs as "unnecessary" because they were "incurred during the uneconomic must-run hours," after subtracting for must-run hours related to testing and meeting VCHEC's biomass consumption requirement.[91] He further opined that the Commission may disallow, as "not necessary or reasonable and prudent," RGGI compliance costs during uneconomic must-run hours to meet the VCHEC biomass consumption requirement, which would increase the disallowance from approximately $1.0 million to approximately $2.5 million.[92] Mr. Abbott also recommended that the Company perform a similar analysis to adjust RGGI compliance costs for the period beyond January 2023 that it seeks during any true-up proceedings.[93]

Staff

Commission Staff offered the testimony of **R. Chris Harris**, a Principal Utility Specialist in the Division of Utility Accounting and Finance ("UAF"); **Alexander W. Elmes**, an Associate

[85] *Id.* at 132-134 (Abbott).
[86] Exhibit No. 19 (ER-PE-16); Tr. at 141-143, 146 (Abbott).
[87] Exhibit No. 16 (Abbott Direct) at 22-23.
[88] *Id.* at 23.
[89] *Id.* at 10.
[90] *Id.*
[91] *Id.* at 23.
[92] *Id.* at 24.
[93] *Id.*

Utility Analyst in the Division of UAF; and **Brian S. Pratt** in the Division of Public Utility Regulation ("PUR").[94]

Staff witness **R. Chris Harris** presented a revised Rate Year Rider RGGI revenue requirement of $356,581,248, composed of both actual and forecasted CO_2 allowance expenses and associated financing costs for the period August 2022 through December 2023. He noted this revision is $16,632,786 lower than the Company's requested revenue requirement.[95] According to Mr. Harris, the differences between the Company's and Staff's revenue requirements are that Staff used actual carbon emissions as the basis for allowance requirements, used three additional months of actual emissions data, and used additional auction purchase data.[96]

Mr. Harris reviewed the Company's actual and projected CO_2 allowance activity for the period September 2020 through March 2024 and concluded that Dominion has acquired or has estimated future purchases of allowances equal to its CO_2 emissions for each of the three years (2021, 2022, 2023) that comprise the RGGI fifth control period.[97] He concluded that based on both actual and projected data, "the Company should be able to reduce their December 2023 allowance auction purchases and avoid the March 2024 auction."[98]

Mr. Harris reported that Staff reviewed Dominion's CO_2 emissions, allowance purchase costs and their amortization.[99] He concluded that purchased allowance quantities and prices agree with allowance activity quarterly amounts. He also reviewed the Company's CO_2 emissions allowance amortization costs and stated that Staff generally used the same methodology as the Company to assign values to allowances being amortized.[100]

Mr. Harris reported that Staff also reviewed Dominion's CO_2 allowance requirements forecasts, noting that the 2023 forecast is 17% higher than actuals for 2022.[101] He stated that Staff did not adjust the Company's forecast when Staff calculated the Rider RGGI revenue requirement,[102] noting that while the winter was "the mildest on record," summer could be warmer than usual.[103] Mr. Harris reported that Dominion based allowance requirements on the assumption of Virginia exiting RGGI at the end of 2023, and any excess allowances the Company has at that time may be resold in a future auction or, if Virginia does not exit RGGI,

[94] Brian S. Pratt adopted the pre-filed direct testimony of Timothy A. Morris on behalf of Commission Staff. Consequently, this Report refers to Mr. Morris' pre-filed testimony as that of its sponsoring witness, Mr. Pratt.
[95] Exhibit No. 21 (Harris Direct) at 1-3 and Schedule 1. The derivation of the revenue requirement is set forth *id.* at Schedule 2.
[96] *Id.* at 4.
[97] *Id.* at 6 and Schedule 6.
[98] *Id.* at 6.
[99] *Id.* at 6-8.
[100] *Id.* at 8.
[101] *Id.*
[102] *Id.* at 8-9.
[103] Tr. at 176 (Harris).

may be used to meet obligations in the next RGGI compliance period.[104] He testified that the revenue requirement set in this case is subject to a future true-up that will reflect the Company's actual expenses.[105]

Mr. Harris described the Rider RGGI expenses. He stated these comprise Virginia jurisdictional allowance amortizations for September through December 2023 and cost deferrals, comprised of allowance amortizations and financing costs of rate base from August 2022 through August 2023.[106] Mr. Harris also summarized the Rate Year rate base, which is a 13-month average (August 2023 – August 2024) of unamortized deferred costs, cash working capital, and allowance inventory balances. He reported the total Virginia 13-month average rate base is $101,122,000.[107]

Staff witness **Alexander W. Elmes** addressed Dominion's capital structure and cost of capital used to calculate the Rider RGGI revenue requirement. He stated that Staff verified Dominion's 2020 cost of capital and supports its use in calculating the revenue requirement. As to the 2021 capital structures, Mr. Elmes stated that the there are two small differences between the Company's and Staff's calculation of the cost of short-term debt; these "have a negligible impact" on weighted average cost of capital ("WACC") beyond three decimal places.[108] Mr. Elmes provided Schedules 1-3 with Staff's calculations of capital structure and cost of capital for the period ending December 31, 2020,[109] the period January 1 – November 17, 2021,[110] and the period as of November 18, 2021.[111]

Staff witness **Pratt** provided an overview of RGGI, of the history of Rider RGGI-related filings leading up to the filing of the Petition, and a synopsis of the Petition itself.[112] He stated that Staff does not object to Dominion's use of PLEXOS to project its allowance requirements, and that Dominion's methodology to estimate its allowance requirement through December 31, 2023, appears reasonable.[113] He noted that Staff takes no position on the assumption of Virginia leaving RGGI at the end of 2023.[114] He also reviewed the Company's methodology for estimating CO_2 allowance prices. He concluded Staff believes the Company's short-term allowance price forecasts appear reasonable and does not oppose the Company's use of forward market pricing in this case.[115]

[104] Exhibit No. 21 (Harris Direct) at 9.
[105] Tr. at 176-177, 188 (Harris).
[106] Exhibit No. 21 (Harris Direct) at 9-10. *See also id.* at Schedules 4 and 5.
[107] *Id.* at 10 and Schedule 3.
[108] Exhibit No. 23 (Elmes Direct) at 3.
[109] *Id.* at Schedule 1.
[110] *Id.* at Schedule 2.
[111] *Id.* at Schedule 3.
[112] Exhibit No. 24 (Pratt Direct) at 2-5.
[113] *Id.* at 6-7.
[114] *Id.* at 7.
[115] *Id.*

Mr. Pratt also reviewed Petition Exhibit 1, which reported that Dominion projected CO_2 emissions by modeling system dispatch under assumptions that are consistent with the Company's 2022 IRP Update Alternative Plan B and with its 2022 RPS Plan. He stated that Staff raised concerns about Dominion's modeling of RGGI in Case No. PUR-2022-00124 and was noting them for the record in this case as well.[116]

Mr. Pratt also addressed the Company's proposal to allocate Rider RGGI compliance costs on an energy basis. He stated this proposal is generally consistent with the methodology approved in the *Initial Rider RGGI Final Order*, with two caveats.[117] First, Dominion proposes to calculate Virginia jurisdictional allocation factors on a monthly, instead of annual basis, to match the monthly allocation methodology for the Company's fuel costs.[118] Second, Dominion proposes to remove load associated with its North Carolina jurisdiction due to the ruling by the North Carolina Utilities Commission that Dominion may not recover RGGI costs from North Carolina customers.[119] Mr. Pratt stated that Staff does not oppose either of these proposals.[120]

Mr. Pratt concluded that Staff does not oppose Dominion's proposed allocation of Rider RGGI costs and its Rider RGGI rate calculation. He recommended that, should the Commission approve a revenue requirement differing from that requested by the Company, the Rider RGGI charge should be adjusted proportionately.[121]

Dominion – Rebuttal

In rebuttal, Dominion offered the testimony of **George E. Hitch**, Senior Market Originator; **Paul M. McLeod**, Director – Regulatory Accounting; and **Jacqueline R. Vitiello**, Director of Power Generation Regulated Operations.

Company witness **George E. Hitch** responded to the pre-filed testimony of Staff witness Harris. In response to Mr. Harris' statement that Dominion should be able to reduce purchases in the December 2023 auction, Mr. Hitch explained such reductions would be feasible only "if emissions in the months preceding the auction are materially below the forecast."[122] Mr. Hitch agreed with Mr. Harris that Dominion could use excess allowances for the next RGGI compliance period if Virginia remains in RGGI past December 2023.[123] As to reselling excess allowances if Virginia exits RGGI at the end of 2023, Mr. Hitch stated that the Company would sell them in the secondary market but not in a future RGGI auction since only RGGI member states are authorized sellers in RGGI auctions.[124]

[116] *Id.* at 8-9.
[117] *Id.* at 10.
[118] *Id.* at 10-11.
[119] *Id.* at 12.
[120] *Id.* at 11-13.
[121] *Id.* at 14.
[122] Exhibit No. 26 (Hitch Rebuttal) at 2.
[123] *Id.*
[124] *Id.*

Company witness **Paul M. McLeod** responded to Staff witness Harris' testimony concerning the Rider RGGI revenue requirement. Mr. McLeod stated that Dominion accepts Mr. Harris' recommended Projected Cost Recovery Factor of $356.581 million.[125] Mr. McLeod referred to this figure as a placeholder to be trued-up in a Rider RGGI update proceeding. He also noted that the appropriate amount of RGGI costs that will flow through base rates will be reviewed during Dominion's next base rate review. He stated that the Company reserves the right to change its methodology for calculating the RGGI revenue requirement in these upcoming cases.[126]

Based on the revised revenue requirement, Mr. McLeod noted that the bill of the 1,000 kWh/month residential user would increase by $4.44/month, a $0.20 decrease from the bill impact estimate for this same customer reported in the direct testimony of Company witness Givens.[127]

During the hearing, Mr. McLeod also testified further concerning the overstatement of Dominion's actual data for the failure to exclude ODEC's share of allowances related to the Clover facility. He opined that if a correction for this overstatement were made, "because it lies in the actual emissions amounts that are in the schedule and historical period that's split between base [rates] and Rider [RGGI], . . . the amount that's going to base rates would be reduced and, as a result, it would push more cost into the Rider."[128] The effect, he suggested, would be to cause the Rider RGGI Projected Cost Recovery Factor to increase.[129]

Company witness **Jacqueline R. Vitiello** responded to APV witness Abbott concerning Dominion's dispatch decisions and market operations of the Company's coal fleet.[130] Ms. Vitiello generally responded that Mr. Abbott bases his analysis on incorrect assumptions and a misunderstanding of how the Company operates."[131]

Ms. Vitiello gave an overview of how economic dispatch works within PJM and reviewed the four commit status options, including economic and must-run, for offering a unit into the day-ahead PJM market.[132] She explained that the main reasons for committing a unit at must-run status include testing and maximizing a unit's economic dispatch over a multi-day period.[133] She noted that PJM views only the next 24 hours, whereas the Company considers the next five-day forecast, when making decisions about whether a unit is economic to run.[134]

[125] Exhibit No. 27 (McLeod Rebuttal) at 2-3.
[126] *Id.* at 2.
[127] *Id.* at 3.
[128] Tr. at 212 (McLeod).
[129] *Id.* at 212, 215 (McLeod).
[130] Exhibit No. 29 (Vitiello Rebuttal) at 1. A confidential (Exhibit No. 29C) version of this testimony was admitted during the hearing. Only the public aspects of the testimony are summarized herein.
[131] *Id.* at 2-3.
[132] *Id.* at 4-5.
[133] *Id.* at 5-6.
[134] *Id.* at 5.

In response to Mr. Abbott's criticisms that the Company's modeling (on economic dispatch) differs from its practice of self-scheduling generation, Ms. Vitiello explained that modeling and operations are conducted by separate business groups within the Company and that some must-run scheduling for testing is included in modeling where it is more predictable. In contrast to modeling's long-term focus, Ms. Vitiello stated that the operations group is concerned with near-time and real-time Company operations, considering factors that are difficult to include in a long-term forecast, such as weather, permit requirements, individual unit characteristics, and outage and testing schedules.[135] She provided reasons for must-running the Company's coal units for each day that Mr. Abbott claimed self-scheduling was uneconomic.[136] She also discussed why the Company would self-schedule a unit for a longer period than it would take that unit to start up.[137] She explained that when reliability is a concern, Dominion might must-run a unit earlier than it would be called upon by PJM to ensure the unit has no technical difficulties starting up. She cited one instance in which the Company did not must-run a unit before PJM dispatched it, and the Company incurred PJM penalties when that unit did not start properly.[138]

Ms. Vitiello claimed that Mr. Abbott's analysis cherry-picks hours where units were uneconomic instead of looking over daily or multi-day horizons of unit operation. She asserted that looking at only hourly margins is not prudent and conflicts with how the Company dispatches generating units.[139] She also addressed how Dominion considers reliability of electric service when making dispatch decisions, noting examples of times when the Company kept generating units online, even though they were uneconomic to run on a certain day, because forecasts of upcoming weather indicated the Company would need these units' production in the next few days.[140] One such event was Winter Storm Elliott in 2022. Ms. Vitiello reported that its coal units had negative economic margins on December 22, 2022, and opined that if Dominion had waited for PJM to dispatch the Company's coal units, they may not have been online when needed on December 23.[141] Ms. Vitiello urged the Commission not to disallow the CO_2 allowance costs associated with the Company's self-scheduling of units on December 22, which, at $320,303, are a significant portion of the costs Mr. Abbott seeks to exclude.[142]

In response to Mr. Abbott's overall request to disallow allowance costs related to uneconomic dispatch, Ms. Vitiello claimed Mr. Abbott wrongly assumed that a negative margin for a unit for any given hour means the unit is uneconomic, and he failed to analyze the impacts to the PJM market if Dominion had not dispatched its coal units as must-run. She surmised that if Dominion had designated the units as economic instead of must-run, the LMPs for those days

---

[135] *Id.* at 6-7.
[136] Exhibit No. 28 and 28C (DEV-PE-1); Tr. at 222-223 (Vitiello). *See also* Tr. at 227-231 (Vitiello).
[137] Tr. at 239-242 (Vitiello).
[138] *Id.* at 244-246 (Vitiello).
[139] Exhibit No. 29 (Vitiello Rebuttal) at 8-9.
[140] *Id.* at 10-11. *See also* Exhibit No. 28 (DEV-PE-1) (corrected Table 2).
[141] Exhibit No. 29 (Vitiello Rebuttal) at 11-12. *See also* Tr. at 230-231 (Vitiello).
[142] Exhibit No. 29 (Vitiello Rebuttal) at 12.

would have been different, likely higher, and Dominion probably would have been buying power at that higher cost.[143]

In response to Mr. Abbott's particular concerns about the Company's dispatch of VCHEC, Ms. Vitiello stated that Dominion already proactively manages how much biomass VCHEC consumes, with specific attention to how much biomass the facility can burn in a one-boiler versus a two-boiler configuration. She explained that the Company runs VCHEC at times that generally have the highest LMPs so the facility can run continuously for longer periods.[144] She argued that Dominion uses the must-run status option within PJM to operate VCHEC in a way that it can comply with the 10% biomass requirement in its DEQ permit; thus, the allowance costs associated with running the plant under must-run conditions should be recovered.[145]

In response to Mr. Abbott's recommendation that the Commission require Dominion to document permit-related must-run decisions for VCHEC, Ms. Vitiello stated that Dominion already documents these decisions for its entire coal fleet, as the Commission directed in Case No. PUR-2022-00064.[146] Likewise, Ms. Vitiello urged the Commission to reject Mr. Abbott's recommendation that the Commission require Dominion to perform an analysis like his to uncover unnecessary RGGI compliance costs incurred after January 2023. She stated that the Commission has denied requests in the past to disallow costs associated with units' must-run status, and the Commission should do so here.[147]

Ms. Vitiello also testified concerning costs included in Dominion's emissions forecast for three biomass units, for whose emissions Dominion does not need to purchase allowances. She testified that these units are about 51 megawatts ("MW") each and that the units' start-up time (but not their run time) was included in the emissions forecast. She explained that these units run nearly constantly, so the impact on the forecast of including these units' start-up times was minimal, approximately 0.01%.[148]

---

[143] *Id.* at 13-14.
[144] *Id.* at 15-16.
[145] *Id.* at 17. *See id.* at 14-15 and Tr. at 232-233, 235-236 (Vitiello) for an explanation of the biomass percentage calculation DEQ uses to judge whether VCHEC is in compliance with its biomass permit.
[146] Exhibit No. 29 (Vitiello Rebuttal) at 17. *See also Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia*, Case No.PUR-2022-00064, Doc. Con. Cen. No. 220920050, Order Establishing 2022-2023 Fuel Factor at 7 n.20 (Sept. 16, 2022) (hereinafter, "*2022 Fuel Order*").
[147] Exhibit No. 29 (Vitiello Rebuttal) at 19.
[148] Tr. at 225-226 (Vitiello).

APPLICABLE LAW

In 2020 the Virginia General Assembly enacted the Clean Energy and Community Flood Preparedness Act, Code § 10.1-1329 *et seq.* ("Clean Energy Act").[149] Through the Clean Energy Act, the General Assembly authorized the Executive Director of the Department of Environmental Quality "to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article."[150]

The focus of the market-based trading program, known in regulations as the CO_2 Budget Trading Program,[151] is a requirement that owners and operators of each electric generating unit that has a nameplate capacity equal to or greater than 25 MW purchase and hold, for compliance deduction at designated intervals, one allowance for each short ton of CO_2 emissions produced by that generating unit.[152] The Clean Energy Act defines an allowance as "an authorization to emit a fixed amount of carbon dioxide,"[153] and DEQ regulations specifically define a "CO_2 allowance" as "a limited authorization by the [DEQ] or participating state under the CO_2 Budget Trading Program to emit up to one ton of CO_2, subject to all applicable limitations contained in this part."[154] If there are not enough allowances to cover emissions at designated times, DEQ or its agent will require three times the number of allowances to cover the excess emissions.[155]

For incumbent electric utilities like Dominion, the costs of allowances are passed on to ratepayers.[156] In its Petition, Dominion requests to recover these costs from ratepayers through a rider mechanism pursuant to Code § 56-585.1 A 5 e. Enactment Clause 2 of the Clean Energy Act authorizes recovery through this mechanism, stating:[157]

> That the costs of allowances purchased through a market-based trading program consistent with the provisions of Article 4 (§ 10.1-1329 et seq.) of Chapter 13 of Title 10.1 of the Code of Virginia as added by this act are deemed to constitute environmental compliance project costs that may be recovered by a Phase I Utility or Phase II Utility, as defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, pursuant to subdivision A 5 e of § 56-585.1 of the Code of Virginia.

---

[149] 2020 Va. Acts chs. 1219, 1280. The Clean Energy Act was amended in 2021 to change references therein to the former Department of Mines, Minerals and Energy to its new name, the Department of Energy. 2021 Va. Acts ch. 532 (Sp. Sess. I).
[150] Code § 10.1-1330 B.
[151] 9 VAC 5-140-6020 C.
[152] 9 VAC 5-140-6040 A; 9 VAC 5-140-6050 C; 9 VAC 5-140-6260 A and B; *Appalachian Voices v. State Corp. Comm'n*, __ Va. __, 879 S.E.2d 35, 36 (2022).
[153] Code § 10.1-1329.
[154] 9 VAC 5-140-6020 C.
[155] 9 VAC 5-140-6050 C; 9 VAC 5-140-6260 D 1.
[156] *See Appalachian Voices v. State Corp. Comm'n*, __ Va. __, 879 S.E.2d 35, 36 (2022).
[157] 2020 Va. Acts chs. 1219, 1280, Enactment Cl. 2. Dominion is a Phase II Utility.

Moreover, Code § 56-585.1 A 5 e reads in pertinent part as follows:

> 5. A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of the following costs:
>
> . . .
>
> e. Projected and actual costs of projects that the Commission finds to be necessary . . . to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the costs of allowances purchased through a market-based trading program for carbon dioxide emissions. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations;

Additionally, Code § 56-585.1 D reads in pertinent part as follows:

> The Commission may determine, during any proceeding authorized or required by this section, the reasonableness or prudence of any cost incurred or projected to be incurred, by a utility in connection with the subject of the proceeding. A determination of the Commission regarding the reasonableness or prudence of any such cost shall be consistent with the Commission's authority to determine the reasonableness or prudence of costs in proceedings pursuant to the provisions of Chapter 10 (§ 56-232 et seq.).

The Supreme Court of Virginia has confirmed that both of these provisions apply to the case at hand, stating "Code § 56-585.1(A)(5)(e) requires the compliance costs to be 'necessary' in addition to being 'reasonable[ ] or pruden[t]' under Code § 56-585.1(D)," and stating that these standards "are related but not identical."[158] The Court has also instructed, in regard to Code § 56-585.1 A 5 e, that "[i]t is thus the necessity to *comply* with applicable laws or regulations that matters."[159]

---

[158] *Appalachian Voices v. State Corp. Comm'n*, __ Va. __, 879 S.E.2d 35, 37 (2022). *See also Initial Rider RGGI Final Order*, 2021 S.C.C. Ann. Rep. at 276 ("In each case, the Company must establish that the costs included in the requested revenue requirement are reasonably and prudently incurred and are 'costs of allowances purchased through a market-based trading program for [CO_2] emissions . . . necessary to comply with [state or federal] environmental laws or regulations.'").

[159] *Appalachian Voices v. State Corp. Comm'n*, __ Va. __, 879 S.E.2d 35, 38 (2022).

Virginia began participating in RGGI on January 1, 2021.[160] DEQ subsequently published its intent to develop a regulation to repeal Article VII of 9 VAC 5-140 pursuant to Executive Order 9.[161] This proposed regulation was published on January 30, 2023, and comments on the proposed regulation were due March 31, 2023.[162] The proposed effective date for repeal is December 31, 2023.[163]

ANALYSIS

No case participant disputes that RGGI is "a market-based trading program for [CO_2] emissions," pursuant to Code § 56-585.1 A 5 e. With this in mind, my analysis will focus on: (1) projected and actual costs of CO_2 allowances (including proposed adjustments); (2) projected and actual allowance prices; (3) revenue requirement, cost allocation, and rate design; and (4) other considerations.

Projected and Actual CO_2 Allowance Costs (Code § 56-585.1 A 5 e)

As proposed, Rider RGGI would cover RGGI compliance costs for the period August 1, 2022, through December 31, 2023.[164] The Company explains its plan to purchase the majority of allowances in quarterly RGGI auctions, specifically purchasing approximately 25% of its forecasted requirement in each auction. The Company plans to fill any shortfall with purchases from the secondary allowance market.[165] Dominion is not banking allowances but instead is purchasing allowances to offset emissions that already have occurred.[166]

For the August 1, 2022 through December 31, 2023 period, Dominion projects it will need approximately 31 million CO_2 allowances to offset emissions from its generating units based on simulations run in PLEXOS software.[167] The Petition uses actual data for August through September 2022; during those months, the Company's generating fleet emitted 3,631,106 tons of CO_2.[168]

Staff reviewed actual data through December 2022 to recalculate Dominion's revenue requirement. Staff calculated that Dominion had over-estimated emissions for the September

[160] 9 VAC 5-140-6020.

[161] 39:3 Va. Reg. Regs. 57-58 (Sept. 26, 2022).

[162] 39:12 Va. Reg. Regs. 1436 (Jan. 30, 2023). The proposed rule was published with the following Editor's Note: "On December 19, 2022, the Joint Commission on Administrative Rules … voted to object to the regulatory action repealing Part VII (9VAC5-140-1060 et seq.) of Regulations for Emissions Trading (9VAC5-140)." *Id.*

[163] Proposed Rule 9 VAC 5-140-6445, found in 39:12 Va. Reg. Regs. 1465 (Jan. 30, 2023).

[164] Exhibit No. 2 (Petition) at 5.

[165] *Id.* at 5; Exhibit No. 3 (Hitch Direct) at 6.

[166] Exhibit No. 3 (Hitch Direct) at 6-7.

[167] Exhibit No. 2 (Petition) at 5; Exhibit No. 3 (Hitch Direct) at 5; Exhibit No. 9 (Matzen Direct) at 2.

[168] *See* Exhibit No. 2 (Petition) Schedule 46A, Statement 1 page 2.

through December 2022 timeframe by 1,003,992 short tons of CO_2. Additionally, Staff used actual emissions from Dominion's Virginia CO_2-emitting generating units from January 2021 through December 2022 to update the number of allowances the Company requires for RGGI compliance over the fifth control period (calendar years 2021-2023). This shifted the timing of certain charges and rate base balances. Due to these changes, Staff calculated slightly different allowance quantities and costs.[169]

APV also reviewed the Company's allowance costs. APV has requested that certain costs be excluded from Rider RGGI as unnecessary or unreasonable and imprudent. These costs fall into 5 areas:

1. *Self-Scheduling Adjustment 1*: A proposed reduction to account for the uneconomic must-run dispatch of coal units (except for must-run hours related to testing and hours VCHEC must run to comply with its DEQ biomass permit requirement). APV proposes a cost disallowance of $1,033,681 for August 2022 through January 2023.[170]

2. *Self-Scheduling Adjustment 2*: A proposed reduction in RGGI costs for those must-run hours for VCHEC to comply with the biomass requirement in its environmental permit. APV proposes an additional cost disallowance of $1,452,100 for August 2022 through January 2023 for this adjustment.[171]

3. *Over-Forecast Adjustment*: A proposed reduction to correct for the overestimation of allowances Dominion will need through 2023, which could partially be ameliorated by updating forecasted costs to actuals for January through March 2023. This adjustment is an unquantified amount that APV described as "a significant number, not de minimis."[172]

4. *Biomass Adjustment*: A proposed reduction to correct the allowance forecast because Dominion included allowances to offset emissions related to start-up power at three

[169] Exhibit No. 21 (Harris Direct) at 4-5.
[170] Exhibit No. 16 (Abbott Direct) at 23-24; Exhibit No. 15 (ER-PE-10). *Also compare* Tr. at 164 (Abbott) ("So we did not recommend a hard number to come out, but I may need to confer with my client to see what their position is on that. I merely calculated the dollar costs that are associated with my analysis.") with Tr. at 253 (Benforado) (reiterating APV's recommendation to "[d]isallow the 1 million dollars of RGGI compliance costs due to the uneconomic self-scheduling practices identified by Mr. Abbott.").
[171] Exhibit No. 16 (Abbott Direct) at 24; Exhibit No. 15 (ER-PE-10). To determine the $1,452,100, I subtracted the uneconomic must-run hours less testing and biomass requirement hours, RGGI cost, from the uneconomic must-run hours less testing hours, RGGI cost ($2,485,781 - $1,033,681 = $1,452,100). *Also compare* Tr. at 164 (Abbott) ("So we did not recommend a hard number to come out, but I may need to confer with my client to see what their position is on that. I merely calculated the dollar costs that are associated with my analysis.") with Tr. at 253 (Benforado) (reiterating APV's recommendation to "in its discretion, disallow the 1.5 million due to the VCHEC self-scheduling practices. . ..").
[172] Tr. at 251 (Benforado).

Dominion biomass units (Altavista, Hopewell, and Southampton). Dominion estimated this adjustment would have a 0.01% effect on the forecast.[173]

5. *Clover Adjustment*: A proposed reduction to correct the overstatement of allowance costs for Clover Units 1 and 2 to remove, from actual data, the 50% portion of allowance costs supplied by ODEC, a co-owner of these units.[174] This adjustment is an unquantified amount that Dominion initially estimated would likely be "a small change to the overall revenue requirement"[175] and "two or three percent" of allowances in total, but later suggested would increase the Rider RGGI revenue requirement.[176]

Self-Scheduling Adjustments 1 and 2

APV witness Abbott expressed concerns with Dominion's use of must-run dispatch for its fossil units when it is uneconomic to do so (*i.e.*, the unit's dispatch cost, including costs of RGGI compliance, exceeds the PJM hourly energy price).[177] He argued that Dominion should not be allowed to recover all RGGI costs from uneconomic dispatch that was caused by Dominion management decisions that do not align with the competitive market.[178]

Mr. Abbott reviewed Dominion's must-run dispatch of its Virginia coal fleet[179] over the period August 1, 2022, through January 31, 2023, identifying hours he determined were uneconomic.[180] He then made a daily adjustment, which enabled him to account for times when even though particular hours of must-run dispatch were uneconomic, it was nevertheless economic for the Company to run that plant over the day of which the uneconomic hours were a part.[181] He next removed uneconomic must-run dispatch hours related to unit testing. He acknowledged that "testing is scheduled in advance and cannot be avoided. . .. Since testing is necessary, I think those must-run hours were reasonable and prudent."[182] He then considered Dominion's practice of self-scheduling VCHEC to meet the 10% biomass requirement in its

---

[173] Tr. at 225-226 (Vitiello).
[174] *See, e.g.*, Tr. at 87-90 (McLeod) (discussing the overstatement of RGGI costs related to the Clover units and clarifying that "the ODEC share is excluded from the . . . forecasted period, but we did observe that it was embedded within the actuals; however, because the spreadsheet . . . [is] taking just the whole emissions for the entire period into account, at the end of the day, you do end up with some overstatement just in the total forecasted amount for the revenue requirement.").
[175] *Id.* at 90 (McLeod).
[176] *Id.* at 93, 211-212, 215 (McLeod).
[177] Exhibit No. 16 (Abbott Direct) at 6, 9.
[178] *Id.* at 10.
[179] Mr. Abbott specifically reviewed must-run dispatch related to the Company's Chesterfield Units 5 and 6, Clover Units 1 and 2, and VCHEC. *See id.* at 20.
[180] *Id.* at 18.
[181] *Id.* at 20-21.
[182] *Id.* at 16.

DEQ permit, noting, "It is not clear whether the must-run hours necessary to meet the biomass requirements could have been avoided or not."[183]

Dominion disagreed with these proposed adjustments. Company witness Vitiello asserted that the Company "works diligently to dispatch all units across the fleet in the most economic manner possible for customers within the confines of market, regulatory, and reliability considerations."[184] She highlighted the Company's practice of considering the forecast for the upcoming five days, as opposed to PJM's day-ahead view, when Dominion is making decisions whether to dispatch units in must-run status.[185] She asserted that Dominion considers multiple factors when deciding whether to use the must-run dispatch option, including: whether a unit that appears uneconomic to run on a given day could be economic to run over a multi-day period, a unit's start-up costs and minimum run times, reliability concerns (continuing to run a unit that cannot quickly cycle to assure its availability when needed), equipment degradation and maintenance costs that occur when starting units repeatedly, unit outage and testing schedules, weather, and permit conditions.[186]

As to VCHEC specifically, Ms. Vitiello asserted that Dominion self-schedules this unit to ensure it complies with its DEQ permit, and the Company should be allowed to recover these compliance costs.[187] Ms. Vitiello explained that the biomass percentage is equal to the current year's biomass heat input divided by the three-year average total heat input, using a compliance year that starts July 1 and ends June 30.[188]

As a preliminary matter, I note that I view the self-scheduling decisions themselves as relevant to the Commission's consideration of whether Dominion's proposed costs are reasonably and prudently incurred. That is, if Dominion's must-run decisions are reasonable and prudent, then the costs for the allowances to cover the emissions related to those must-run decisions would be necessary costs to comply with RGGI.

Impact of *2022 Fuel Order*. Dominion's practice of self-scheduling generating units in the PJM Day-Ahead market also was an issue in the Company's most recently decided fuel factor proceeding. Therein, the Commission agreed with a finding of the Chief Hearing Examiner that "'[b]ased on the record in this proceeding, the process by which Dominion Energy self-schedules its generating units, including its coal units, appears to be reasonable and designed to provide lower overall fuel costs for its customers.'"[189] The Commission further stated that they "'do not find it speculative, nor does it appear to be in customers' [best] interest for the Commission to prohibit self-scheduling going forward.'"[190] The Commission instructed

---

[183] *Id.* at 16-17.
[184] Exhibit No. 29 (Vitiello Rebuttal) at 19.
[185] *Id.* at 5.
[186] *Id.* at 5-7, 10-13. *See also* Exhibit Nos. 28 and 28(C) (DEV-PE-1) (documenting reasons for self-scheduling units).
[187] Exhibit No. 29 (Vitiello Rebuttal) at 17.
[188] *Id.* at 14.
[189] *2022 Fuel Order* at 6-7 (Sept. 16, 2022) (internal citation omitted).
[190] *Id.* at 7 (internal citation omitted).

Dominion to continue to keep its commitments to "'work[] diligently to dispatch all units across the fleet in the most economic manner possible for customers within the confines of market, regulatory, and reliability considerations'" and "to 'prudently dispatch[] and manag[e] the generation fleet to deliver safe, reliable, and affordable power to [] customers.'"[191]

APV attempts to distinguish its position in this case from the *2022 Fuel Order*. Mr. Abbott testified, "[T]hat case was about the recovery of fuel costs, not RGGI compliance costs. The current case is the first time the recovery of RGGI costs has been drawn into question from examining the uneconomic must-run dispatch of the coal units."[192]

Though RGGI costs were not a specific subject the Commission considered in the *2022 Fuel Order*, fuel costs and RGGI compliance costs are inextricably intertwined outputs of running fossil-fueled generating units. That is, if the Company runs a fossil-fueled generating unit, the Company will physically emit CO_2 from burning that fossil fuel, with the quantity of CO_2 emitted varying depending on the fuel.[193] And since Virginia currently is part of RGGI, Dominion will incur both the cost for the fossil fuel needed to run the unit, and the cost of one allowance for each short ton of CO_2 emitted by that unit while it burns that fossil fuel.[194]

The inextricable intertwinement of fuel costs and RGGI compliance costs can be seen from APV's own analysis. When discussing the economics of must-run dispatch of Dominion's VCHEC facility to meet its biomass permit requirement during the August 2022 through January 2023 timeframe, APV witness Abbott calculated a net loss, *i.e.* an uneconomic dispatch cost, of approximately \$3.5 million.[195] He explained, "Thus, out of the three and a half million-dollar total loss shown in column three, about one and a half million are RGGI costs that are proposed to be collected from customers through Rider RGGI, and the remaining \$2 million will be collected from customers through the fuel factor."[196] Accordingly, APV's own analysis demonstrates that any calculation of net gain or loss resulting from must-run dispatch necessarily involves consideration of both fuel and RGGI compliance costs.

Based upon the foregoing considerations, as long as Virginia remains in RGGI, it is difficult to imagine a scenario in which the cost of fuel a unit burns during self-scheduled hours is reasonable (as the Commission found in the *2022 Fuel Order*), and at the same time the costs of the allowances to offset the CO_2 emissions directly caused by burning that fuel are deemed to be unreasonable and unnecessary. This is a legal needle that cannot be threaded.

---

[191] *Id.* (internal citation omitted).
[192] Tr. at 118 (Abbott).
[193] *See, e.g.*, Exhibit No. 16 (Abbott Direct) at 17-18 ("Further, Dominion's gas units have lower CO_2 emission rates compared to the coal units.").
[194] *See* Exhibit No. 14 (Givens Direct) at 2 ("The need for allowances is driven by the dispatch and output of generators that emit CO_2."); Exhibit No. 24 (Pratt Direct) at Attachment TM-2 (where in response to Question No. 27 of Staff's sixth set of discovery requests, Dominion stated, "This dispatch and operation of such generators using fossil fuels causes the need to purchase allowances similar to the need to purchase fuel to operate such generators").
[195] Tr. at 139-141 (Abbott); Exhibit No. 19 (ER-PE-16).
[196] Tr. at 141 (Abbott).

Analysis of what is uneconomic. Additionally, the crux of APV's contention is that Dominion's self-scheduling is *uneconomic*. I have three primary concerns with the analysis APV used to determine which self-scheduled hours were uneconomic.

First, APV determined what costs it argues should be disallowed on an after-the-fact basis. Mr. Abbott explained:[197]

> 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 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.

Next Mr. Abbott calculated the amount of RGGI costs incurred during hours of uneconomic must-run dispatch for each coal unit, using both the actual monthly emission rate for each unit over the August 2022 through January 2023 period and using the actual average allowance price of $13.15 that Dominion incurred over that six-month period.[198] He then examined each day that included any hours of uneconomic must-run dispatch and removed the RGGI costs related to the uneconomic must-run hours if, over the entire 24-hour period, there was a net gain.[199] He next removed uneconomic hours that were needed for testing or to meet VCHEC's biomass permit requirement and ultimately concluded that the Commission should disallow at least $1.0 million of RGGI compliance costs because he "do[es] not believe that Dominion has established that these costs are necessary or reasonable and prudent."[200]

The above-described analysis is one that determines reasonableness and prudence after-the-fact. The Commission, on the other hand, typically judges what is a reasonable and prudent decision based on the circumstances at the time the decision was made.[201] And there is no way Dominion operations personnel could perform APV's analysis *before* making a must-run decision. For example, Dominion would not know in advance what its actual average allowance price would be for a particular day since Dominion purchases allowances in arrears and does not bank them in advance.[202] Nor would Dominion know, until after a 24-hour period is over,

---

[197] Exhibit No. 16 (Abbott Direct) at 18.
[198] *Id.* at 19.
[199] *Id.* at 21.
[200] *Id.* at 24.
[201] *See, e.g.*, *Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2018-00195, 2019 S.C.C. Ann. Rep. 328, 330, Final Order (Aug. 5, 2019).
[202] Exhibit No. 3 (Hitch Direct) at 7.

whether the Company has made money for that period. APV's analysis seems to be a form of Monday-morning quarterbacking, an attempt to say what Dominion "should have done" after knowing the economic results for a given day, and judging the Company by whether it guessed correctly that it would make money, or at least break even, every day for every unit that is self-scheduled. This, in my view, is contrary to the Commission's practice of how it judges reasonableness and prudence.

My second concern is that APV's position appears to focus on gains and losses in the PJM energy markets. But PJM also has a capacity function, including charging capacity penalties (and bonuses) under certain conditions to generators like Dominion that have elected to operate under the Fixed Resource Requirement alternative (*i.e.*, they self-supply capacity instead of obtaining capacity in the PJM capacity market). To the extent that Dominion has indicated to PJM that a particular unit is one of its capacity resources, and that unit fails to run when PJM calls upon it for reliability reasons,[203] Dominion may incur capacity penalties.

Dominion explained how Winter Storm Elliott provided an example of the influence of capacity requirements on Dominion's self-scheduling practices. Ms. Vitiello explained that in the PJM region, there "were emergency procedures that started at 1617 in the afternoon [on December 23rd] and lasted until 2300 on December 24th. During that time, $1.8 billion in penalties were assessed to units that did not come online or did not make it, were in forced outages."[204] The must-run decisions Dominion made for December 22nd were, according to Ms. Vitiello "to ensure reliability, it wasn't to avoid a start-up cost."[205] When asked why the Company would need to must-run a unit 36 hours before a weather event, Ms. Vitiello explained: "If you wait until the last minute, it's like starting your car when it's super, super cold. Engines just don't start very well when it's cold. So if you wait until the last minute, you could have bugs that you have to work out, ..."[206] She noted that the Company did not self-schedule one of its coal units, Yorktown Unit 3, before Winter Storm Elliott, instead waiting for PJM to dispatch that unit. The unit had difficulty starting, and as a result Dominion incurred several million dollars in capacity penalties.[207]

Third, underlying both of the above concerns is a disconnect between Dominion's and APV's decision-making horizons. Dominion makes self-scheduling decisions by considering the next five days.[208] APV's analysis, on the other hand, judges the reasonableness and prudence of Dominion's self-scheduling decisions by examining net gains and losses on an hourly basis, with a subsequent 24-hour adjustment.[209] APV judges the reasonableness of Dominion's dispatch

---

[203] Tr. at 244 (Vitiello) (stating that when PJM runs a unit for reliability, this means, "They need the unit despite the cost. . .. They need it for reliability. They need it for hot or cold weather. It's a reliability run.") *Id.*
[204] *Id.* at 230 (Vitiello).
[205] *Id.* at 230-231 (Vitiello). She reiterated that "the goal for December 22nd was not to avoid start-up costs, the goal was to have units online for the coldest weather in December." *Id.* at 231.
[206] *Id.* at 245 (Vitiello).
[207] *Id.* at 245-246 (Vitiello).
[208] Exhibit No. 29 (Vitiello Rebuttal) at 5.
[209] Exhibit No. 16 (Abbott Direct) at 18-21.

decisions based on achieving a benchmark (making money or breaking even on an hourly or 24-hour basis) that Dominion is not attempting to achieve. As Ms. Vitiello testified, "The primary reason to choose must-run status is to maximize the economics of a unit's dispatch over a *multiple day* period,"[210] not over an hour or over one 24-hour period. Again, the *2022 Fuel Order* provides the answer. Therein, the Commission agreed with the Hearing Examiner that "'the *process* by which Dominion [] self-schedules its generating units, including its coal units, appears to be reasonable . . ..'"[211] This process includes Dominion's five-day-ahead outlook. The Commission did not require the Company to shorten its decision-making horizon for self-scheduling to a one-hour or 24-hour basis in that case, and there is no reason to do so here.

Self-Scheduling Adjustment 2 – Additional Considerations. APV specifically addressed concerns related to Dominion's VCHEC facility. Dominion must comply with two DEQ requirements as to VCHEC that were discussed in this case, both the RGGI compliance regulation and the particular DEQ permit for VCHEC.[212] Dominion testified that it operates VCHEC in must-run status based at least in part on "the number of days remaining to satisfy the biomass percentage requirement."[213] APV argues that Dominion has not proven the necessity for and reasonableness of RGGI compliance costs for the VCHEC facility because the Company's focus is on compliance with its biomass permitting requirement and not on RGGI compliance costs.[214] APV notes that RGGI compliance costs add to VCHEC's dispatch costs, which "get added and just flow through to customers," when VCHEC loses money through must-run dispatch.[215] At the least, APV argues, Dominion could have more closely managed its biomass fuel mix to avoid uneconomic must-run days at VCHEC.[216]

The way to minimize must-run hours, APV posits, is by not using so little biomass in the fuel mix in the summer that the Company has "such a big hole to fill in the winter."[217] APV suggests that Dominion run VCHEC with a fuel mix consisting of approximately 9% biomass consistently, or another percentage the Commission would deem appropriate.[218] In making this recommendation, Mr. Abbott testified:[219]

> [T]here are some operational concerns, especially when you're trucking things in and burning on a daily basis, . . . you don't want to micromanage it to the point that it makes it too cumbersome.

---

[210] Exhibit No. 29 (Vitiello Rebuttal) at 5 (emphasis added).
[211] *2022 Fuel Order* at 6-7 (Sept. 16, 2022) (internal citation omitted) (emphasis added).
[212] This was acknowledged by Appalachian Voices. *See* Tr. at 237-238 (Benforado cross of Vitiello).
[213] Exhibit No. 29 (Vitiello Rebuttal) at 16.
[214] Tr. at 146 (Benforado questioning Abbott).
[215] *Id.* at 146 (Abbott).
[216] *See generally id.* at 142-146 (Abbott). *See also id.* at 250 (Benforado) ("[T]hose RGGI compliance costs are being inflated by the self-scheduling practices at VCHEC that are being driven not by RGGI compliance costs but by this biomass feedstock issue.").
[217] *Id.* at 144 (Abbott).
[218] *Id.* at 144-145 (Abbott).
[219] *Id.* at 145 (Abbott).

> But on the other hand, just ignoring it with the idea that we'll make it up in the winter when prices are higher, you know, I don't think that's a good strategy.

Dominion resisted this recommendation, noting that VCHEC station engineers, not the Company's dispatch group, determine the quantity of biomass to include in VCHEC's fuel mix, and that the dispatch group is "not saying hold back because we're going to make up this percentage in January or February."[220] Dominion witness Vitiello explained the calculation of the biomass permit requirement as follows:[221]

> So the way the equation works is the numerator has only this year's biomass heat input, and the denominator has the rolling three-year average of the total heat input.
>
> So on July 1st if you're unit is offline, your biomass percentage for the compliance of the three years is 0 percent. The day you start running, it doesn't jump to 9 percent because you're all of a sudden, you know, putting 9 percent biomass in the unit. It's going to be .1 percent and then .2 percent, and it's slowly going to increase over time based on how much you're running.

Based on this testimony, it does not appear that the Company is purposely running VCHEC with a low biomass requirement in summer, at the beginning of its permit year, and creating a biomass deficit that then forces the Company to must-run VCHEC more than necessary to comply with its DEQ permit. Rather, this biomass permitting "hole" seems to develop as a function of the biomass percentage calculation embedded in the DEQ permit.[222] It is unclear whether any fixed percentage of biomass in VCHEC's fuel mix would prevent the "big hole" that APV seeks to eliminate.

Conclusions. In summary, APV's analysis of Dominion's self-scheduling decisions as presented in this record is inconsistent with the holding of the *2022 Fuel Order* that "'the process by which Dominion Energy self-schedules its generating units, including its coal units, appears to be reasonable and designed to provide lower overall fuel costs for its customers.'"[223] APV's analysis, with its focus on net gains or losses from must-run dispatch on an hourly or 24-hour basis, is also inconsistent with the *2022 Fuel Order's* stated expectation that "the Company . . . continue to abide by" its commitment to "'work[] diligently to dispatch all units across the fleet in the most economic manner possible for customers within the confines of market, *regulatory, and reliability* considerations.'"[224] Further, APV's analysis asks the Commission to judge prudence not on the circumstances at the time a decision is made but instead based on after-the-fact determinations.

---

[220] *Id.* at 232 (Vitiello).
[221] *Id.* at 232-233 (Vitiello).
[222] *See* Exhibit No. 29 (Vitiello Rebuttal) at 14-15 for a description of this equation.
[223] *2022 Fuel Order* at 6-7 (Sept. 16, 2022) (internal citation omitted).
[224] *Id.* at 7 (internal citation omitted) (emphasis added).

Specifically as to VCHEC, APV admitted, "It is not clear whether the must-run hours necessary to meet the biomass requirements could have been avoided or not,"[225] and APV misconstrues Dominion's strategy to comply with its DEQ biomass permit for this facility. In my opinion, Dominion has satisfactorily explained the biomass percentage calculation with which it must comply to meet VCHEC's DEQ permit.[226] The Company also has satisfactorily rebutted the concern that its compliance strategy is to "ignor[e] [the biomass percentage] with the idea that we'll make it up in the winter when prices are higher."[227] And the Company has explained how it actively manages the percentage of biomass it uses at VCHEC.[228]

For all these reasons, I find that APV's self-scheduling analysis and proffered adjustments should be rejected.

If the Commission is not inclined to reject this recommendation, APV may need to provide further clarification as to the exact amounts it seeks to have the Commission disallow. After providing cost calculations of $1,033,681 for Self-Scheduling Adjustment 1 and $2,485,781 for Self-Scheduling Adjustments 1 and 2 collectively, APV witness Abbott noted that "we did not recommend a hard number to come out. . .. I merely calculated the dollar costs that are associated with my analysis."[229]

Over-Forecast Adjustment

Concerned that Dominion is over-forecasting the number of allowances it will need through December 2023, APV asked that the revenue requirement be updated. APV noted that Staff's update of the revenue requirement using actual data through the end of 2022 had the effect of correcting the over-forecast through the end of 2022. APV requested the same analysis be done using actual emissions data through March 2023 and that the revenue requirement be updated again. APV stressed, "[W]e think that will be a significant number, not de minimis."[230]

After the hearing, Dominion filed reserved Exhibit No. 8, which provides final actual emissions, by generation facility, for January through March 2023 in addition to the previously provided actual emissions data for August through December 2022.[231] According to this exhibit, Dominion emitted approximately 4.3 million tons of CO_2 from January through March 2023.[232]

---

[225] Exhibit No. 16 (Abbott Direct) at 17.
[226] *See, e.g.*, Tr. at 232-233 (Vitiello).
[227] *Id.* at 145 (Abbott).
[228] *See, e.g.*, Exhibit No. 29 (Vitiello Rebuttal) at 15-16.
[229] Tr. at 164 (Abbott). Mr. Abbott stated his position may be different than that of his client APV. In closing, counsel for APV specifically asked the Commission to "[d]isallow the 1 million dollars" for Self-Scheduling Adjustment 1 and "in its discretion, disallow the 1.5 million due to" Self-Scheduling Adjustment 2. *Id.* at 249 and 253 (Benforado), respectively.
[230] Tr. at 251 (Benforado).
[231] Exhibit No. 8 (Update to Exhibit No. 5).
[232] *Id.* This number was derived by adding up all emissions in the columns titled "January," "February," and "March" on the exhibit.

The Company had forecasted that it would purchase approximately 5.4 million allowances in the March RGGI allowance auction (supplemented by secondary market purchases, if necessary) to cover first quarter 2023 emissions.[233] Further, Staff witness Harris testified that Dominion's "2023 year-over-year carbon allowance forecast is 17% percent [sic] higher than 2022 actuals."[234] Staff did not adjust Dominion's allowance forecast when Staff calculated the revenue requirement, noting that differences between projected and actual allowances amounts and prices will be trued-up in future cases.[235]

There were several reasons given at the hearing as to why the Company's actual experience was lower than predicted, the most significant of which was weather.[236] Company witness Matzen testified that two key inputs to the Company's modeling, the load forecast and forward market prices, are based on normal weather, which was markedly different than actual experience in early 2023.[237] The weather in January and February was described as "extremely mild,"[238] and "record mild," with emissions far below forecasted levels.[239] This milder weather, which in turn lowered the Company's load requirement, combined with lower commodity prices, "were the major drivers of why the actual load generation and carbon emissions were lower than forecast."[240]

The Company and Staff both argued against further updating in this case. Company witness McLeod testified that making updates to forecasts is unusual because doing so is administratively burdensome, because riders are typically capped at noticed amounts, and because rider true-ups are designed to adjust for any over- or under-recoveries from customers.[241] Staff witness Harris testified that, while winter weather was mild, summer 2023 could likewise be warmer than expected, surpassing the forecast.[242] He also noted that all rates set in this proceeding would be subject to a true-up in a future case.[243] Both the Company and Staff noted that any customer refunds due to cost over-recovery would include financing costs.[244]

---

[233] Tr. at 56-57 (Holmes cross of Hitch). *See also* Exhibit No. 2 (Petition) at Schedule 46A, Statement 1 page 2 (showing projected allowance purchases of 5,367,117 for March 2023). Mr. Hitch also testified that Dominion purchased 3.9 million allowances in the March RGGI allowance auction. Tr. at 57 (Hitch).
[234] Exhibit No. 21 (Harris Direct) at 8.
[235] *Id.* at 8-9 and n.16.
[236] Tr. at 58 (Hitch) (describing the warm winter as "the primary driver for reducing the amount of allowances we purchased in March.").
[237] *Id.* at 73-74 (Matzen).
[238] *Id.* at 74 (Matzen).
[239] *Id.* at 58 (Hitch).
[240] Id. at 74 (Matzen).
[241] *Id.* at 212-214 (McLeod).
[242] *Id.* at 176 (Harris).
[243] *Id.* at 176-177, 188 (Harris).
[244] *Id.* at 214 (McLeod); Exhibit No. 21 (Harris Direct) at Appendix A at 1 ("[A]ny difference, plus financing costs applicable to the reconciliation period, is credited to or recovered from customers through the True-Up Factor revenue requirement.").

Under the circumstances of this case, I find updating the Rider RGGI revenue requirement to reflect actual, not forecasted, emissions data for the first quarter of 2023, to limit the impact of possible over-forecasting, is not reasonable or prudent at this time for several reasons.

First, by permitting recovery of "[p]rojected and actual costs," Code § 56-585.1 A 5 e contemplates the use of forecasts and other projections as the basis for developing costs to be recovered through a rate adjustment clause ("RAC") under that statute. Further, since a RAC under this Code provision may be filed "not more than once in any 12-month period," the statute appears to allow, and it is reasonable to expect, that any RAC could include a substantial amount of projected costs.

Second, by virtue of the true-up feature, any Rider RGGI overpayment (should that occur) resulting from an over-forecast of the number of allowances projected to be necessary for RGGI compliance from August 1, 2022, through December 31, 2023, would be temporary. As explained by Staff witness Harris, the purpose of the True-Up Factor in rate adjustment clause cases is[245]

> to credit to or recover from customers any over/under collection of costs from the most recently completed calendar year. Actual revenues recovered during this period are compared to actual costs incurred during the same period and any difference, plus financing costs applicable to the reconciliation period, is credited to or recovered from customers through the True-Up Factor revenue requirement.

If the alleged over-forecast results in customers overpaying RGGI-related costs during the Rate Year, customers will be refunded this overpayment, with financing costs, during a true-up proceeding. Dominion expects to make such a true-up filing.[246]

Third, there is uncontested evidence that a major force behind the over-forecast was weather, which Mr. Hitch described as "one of the mildest winters ever recorded not only in Virginia but, really, in the entire Eastern United States,"[247] and it is unclear whether summer 2023 weather also will deviate significantly from normal weather. The over-forecast could, over the course of 2023, turn out not to be an over-forecast at all, in which case the update APV proposes could cause Dominion to under-recover RGGI-related costs from customers.

Fourth, this is the first three-year control period in which Dominion is participating in RGGI. At the end of the RGGI control period (the end of 2023),[248] Dominion must have

[245] Exhibit No. 21 (Harris Direct) at Appendix A page 1.
[246] Tr. at 217 (Holmes cross of McLeod) ("I think we will need to have another update proceeding, at a minimum, to true-up this projected cost recovery factor that we're putting in place today.").
[247] *Id.* at 58 (Hitch).
[248] Exhibit No. 3 (Hitch Direct) at 3.

purchased enough allowances to cover its emissions for the 2021-2023 period.[249] The penalties for failing to have the required number of allowances to cover emissions is steep: the generator must forfeit three additional allowances per ton of excess emissions.[250] Given the Company's (and Virginia's) relative inexperience with RGGI and steepness of penalties for noncompliance, I consider it prudent for the Company to err on the side of over-forecasting, rather than under-forecasting, emissions and the number of allowances needed to offset them.

Biomass and Clover Adjustments

Dominion acknowledged two errors in its calculations, both of which result in an overstatement of the number of allowances the Company requires. First, the Company overstated its allowance forecast by improperly including emissions associated with start-up fuel for three biomass units of 51 MW each.[251] Biomass fuel is not subject to RGGI.[252] Nevertheless, RGGI compliance costs related to the start-up of three Dominion biomass units was included in the Company's projections (but not in any months for which the Company used actual data). Company witness Vitiello testified that these units run almost all the time and that the effect of this error on the forecast "was .01 percent, very, very minimal."[253] There is no quantification in the record of how much lower the revenue requirement would be if this adjustment were made.

Second, the Company overstated emissions allowances by failing to remove, in the months for which the Company used actual data, the 50% portion of allowances that ODEC supplies for Clover units 1 and 2.[254] This error occurred only in actual Company data, not in

---

[249] *Id.* at 6-8.
[250] *Id.* at 8. *See also* 9 VAC 5-140-6050 C 9 and 9 VAC 5-140-6260 D 1.
[251] Tr. at 225-226 (Vitiello).
[252] *Id.* at 27-28 (Benforado). *See also* Exhibit No. 24 (Pratt Direct) at 2 (explaining RGGI as a collaborative effort where "[t]he participating states have established a regional cap on CO_2 emissions originating from *fossil fuel-fired* power plants. . ..") (emphasis added). Biomass is not a fossil fuel, and participating states do not hold allowances to offset emissions from biomass facilities. I have reviewed and take judicial notice of the following publicly available statement from the RGGI website: "Emissions from eligible biomass should be deducted from the regional total of CO_2 emissions for purposes of calculating emissions from CO_2 budget sources subject to RGGI CO_2 allowance compliance obligations." https://www.rggi.org/allowance-tracking/emissions.
[253] Tr. at 225-226 (Vitiello).
[254] *See* Exhibit No. 13 (ER-PE-6) (in which Dominion states in an interrogatory response, "Upon review of the projected factor revenue requirement, the cost for allowances for forecasted periods may be partially overstated for ODEC's 50% share of Clover. This will be corrected in future Rider RGGI update proceedings."). It was later clarified that the overstatement occurred with respect to actual, not forecasted, data. Tr. at 88-89 ("[S]ome of the actual allowances within . . . that schedule did have this ODEC share of Clover in it, [which] results in there being some overstatement of the total forecast.") and 90 ("[T]he ODEC share is excluded from the . . . forecasted period, but we did observe that it was embedded within the actuals. . ..") (McLeod).

projections.[255] The Company stated this error would be corrected in future Rider RGGI cases.[256] Company witness McLeod first characterized this error as "immaterial" and as something to be "corrected in a future true-up."[257] In rebuttal, Mr. McLeod provided additional information:[258]

> I think to clarify, too, what I said this morning about the impact, I think, directionally, if we were to make this correction for ODEC, because it lies in the actual emissions amounts that are in the schedule and historical period that's split between base [rates] and Rider [RGGI], the result might be that the base – the amount that's going to [be in] base rates would be reduced and, as a result, it would push more cost into the Rider.
>
> So it might be the case that if we were to make this correction, that the projected cost recovery factor would actually go up.

Mr. McLeod further explained to APV counsel Holmes:[259]

> [I]f you were to lower those [actual emissions amounts] back during the base period, it would allocate less of that cost – actual cost to . . . those earlier months. And as a result, . . . the following months in the schedule would be higher, which is what's captured in the projected cost recovery factor.

During the hearing, counsel for both Staff and the Company expressed concern that further updating of costs in this case could create evidentiary challenges.[260] Counsel for Staff specifically was uneasy about the possibility that this Report would "recommend and the Commission [would] approve a number of exclusions from the revenue requirement that we haven't quantified; and that . . . at some point in the future, the Company would file a new revenue requirement that wouldn't be subject to a litigated proceeding."[261] Counsel for the Company acknowledged the concern about "an open-ended continuous update," stating "[T]here's a reason that we file testimony, we pick a point in time, and then we come back the next year and we true it up."[262] She also indicated that there would be "other puts and takes" that could affect the true-up, and concluded that such a course of actions would not be "reasonable or prudent and should not be approved by the Commission."[263]

---

[255] Tr. at 69-70 (Matzen); *id.* at 88-90 (McLeod).
[256] *Id.* at 90 (McLeod) ("[W]e do plan to ensure that that does get corrected in future cases.").
[257] *Id.* at 91 (McLeod).
[258] *Id.* at 211-212 (McLeod).
[259] *Id.* at 215 (McLeod).
[260] *Id.* at 258-260 (Ochsenhirt) and at 266-267 (Ryan).
[261] *Id.* at 258-259 (Ochsenhirt).
[262] *Id.* at 266 (Ryan).
[263] *Id.* at 266-267 (Ryan).

Upon reflection of all these concerns, I nevertheless find that the Biomass and Clover Adjustments should be made in this case and not held for a true-up proceeding. Without these adjustments, I find that the projected and actual Rider RGGI costs as proposed in the Petition would not meet the standard of "necessary . . . to comply with state or federal environmental laws or regulations" pursuant to Code § 56-585.1 A 5 e.

The Petition was filed pursuant to Code § 56-585.1 A 5 e, which requires consideration of not only what costs are reasonable and prudent, but what costs "the Commission finds to be necessary . . . to comply with state or federal environmental laws or regulations. . .." The Supreme Court of Virginia has stated that "Code § 56-585.1(A)(5)(e) requires the compliance costs to be 'necessary' in addition to being 'reasonable[ ] or pruden[t]' under Code § 56-585.1(D)."[264] In a previous case considering RGGI costs, the Court held that the costs at issue were recoverable "because they were necessary to comply with [Dominion's] statutory duty to purchase allowances for every short ton of CO_2 emitted from its power plants."[265]

Unlike the over-forecasting concern, which could prove by the end of 2023 not to be an over-forecast at all, there are no circumstances under which the costs at issue in the Biomass and Clover Adjustments would be necessary for Dominion to comply with the RGGI program.

Dominion has no obligation to purchase allowances to cover ODEC's share of emissions from the Clover facility. Evidence in this case is that, though Dominion reports and retires allowances for the entire facility, "ODEC is responsible for purchasing allowances to cover . . . their 50 percent share of Clover."[266] ODEC provides these allowances to the Company every February, and indeed provided its contractual portion to Dominion in February 2023.[267] This was part of the reason Dominion only purchased 3.9 million allowances at the March 2023 RGGI auction, instead of the approximately 5.37 million allowances the Company previously estimated it would purchase.[268]

Similarly, Dominion has no statutory (or other) duty to hold allowances in a RGGI account to cover emissions related to start-up fuel at its biomass plants. RGGI does not require participating states to hold such allowances,[269] and Dominion admits it included these costs in error.[270] These costs are phantom costs that no one will ever incur, except for customers, to the extent the costs are left in the calculations that form the basis of the revenue requirement in this case and until the phantom costs are returned via a Rider RGGI true-up.

---

[264] *Appalachian Voices v. State Corp. Comm'n*, __ Va. __, 879 S.E.2d 35, 37 (2022).
[265] *Id.* at __ Va. at __, 879 S.E. 2d at 38.
[266] Tr. at 53 (Hitch). *See also* Exhibit No. 13 (ER-PE-6).
[267] Tr. at 58 (Hitch) ("[E]ach February ODEC delivers their contractual obligation of RGGI allowances to us, so we backed that number out of what we purchased.").
[268] *Id.* at 56-58 (Hitch).
[269] See the publicly available guidance from the RGGI website: "Emissions from eligible biomass should be deducted from the regional total of CO_2 emissions for purposes of calculating emissions from CO_2 budget sources subject to RGGI CO_2 allowance compliance obligations." https://www.rggi.org/allowance-tracking/emissions .
[270] *See, e.g.*, Exhibit No. 10 (ER-PE-7).

Thus, the Clover Adjustment-related costs and the Biomass-Adjustment-related costs are not "necessary" for Dominion "to comply" with RGGI pursuant to Code § 56-585.1 A 5 e. With the condition that the Biomass and Clover Adjustment are made, however, I find that the projected and actual Rider RGGI costs as proposed in the Petition and updated by Staff are "necessary . . . to comply with state or federal environmental laws or regulations" pursuant to Code § 56-585.1 A 5 e and are reasonable and prudent pursuant to Code § 56-585.1 D.[271]

If I were considering a RAC under a different statute, I might be persuaded that these adjustments could be made through a true-up. However, Code § 56-585.1 A 5 e has specific language that does not appear in other sections of the Code establishing RACs, and this language cannot be overlooked. The errors that are the basis of the Biomass and Clover Adjustments are known now, before Rider RGGI will be reinstated. The costs at issue are not "necessary" for Dominion to comply with RGGI, and thus Dominion has not, in my view, met its burden of proof that these costs are legally proper to incorporate into the Rider RGGI calculations that form the basis of the revenue requirement. Nor am I convinced that it is legally allowable or sufficient, for purposes of Code § 56-585.1 A 5 e, to include these unnecessary costs in the revenue requirement now on the premise that they will be corrected in a future true-up.

I now consider how the Clover and Biomass Adjustments can be made procedurally. One option is through a compliance filing, a tool the Commission has used in the past.[272] Given the eight-month deadline for a final order in this case[273] and the need for the Commission to have as much information as possible on which to base its decisions, I direct Dominion to incorporate the Clover and Biomass Adjustments into a compliance filing, to be filed with its comments on this Report. Such a compliance filing should include adjusted Rider RGGI rates and accompanying workpapers that include the recalculation of expense, re-amortization of allowances, and re-computation of rate base and revenue requirement, with associated cost allocation and rate design documentation. Commission Staff should verify these calculations as soon as possible after the compliance filing is made.

While the Company and Staff need to act expeditiously to accomplish these tasks, I do not believe that time is an insurmountable hurdle. Exhibits 10, 10(C), 11 and 11(C) already provide estimated CO_2 emissions by month for January through December 2023 excluding emissions associated with start-up fuel for the biomass units.[274] Thus, that information has been

---

[271] *See Appalachian Voices v. State Corp. Comm'n*, __ Va. __, 879 S.E.2d 35, 37 (2022) ("[I]t is hard to imagine something being necessary and yet unreasonable and imprudent.").

[272] For example, in a recent Appalachian Power Company case, the Commission used the utility's compliance filing as a vehicle to correct for the impact of a legal error. *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, Doc. Con. Cen. No. 221230136, Order on Remand at 9, 11 (Dec. 21, 2022).

[273] *See* Code § 56-585.1 A 7.

[274] Exhibit Nos. 10 (ER-PE-7), 10(C) (ER-PE-7), 11 (ER-PE-9), and 11(C) (ER-PE-9).

compiled, is already part of the evidence taken in a litigated proceeding, and is ready to be incorporated into the calculations that form the basis of the revenue requirement.[275]

The Clover Adjustment is more complicated; evidence in this case is that the error dates back to 2021 and thus impacts the amount of Initial Rider RGGI costs that the Company proposes to recover through base rates (which case will be filed later this year).[276] This is undeniably more work in a short time period. But the Company already has identified the main culprit in the miscalculation – an errant cell in an electronic file.[277] Moreover, this is work the Company would need to do in the very near future regardless, so that it will have the proper RGGI-related calculations to incorporate into base rates as part of the Company's upcoming base rate review. The alternative, in my view, would be harsher – finding that the Petition does not meet the standard of Code § 56-585.1 A 5 e. This result would be worse for both the Company and customers: the Company would experience a delay in cost recovery, and customers would have to pay Rider RGGI later, at perhaps higher rates that will include additional financing costs.

I note that there is uncertainty as to the impact of the Clover Adjustment on the revenue requirement.[278] To the extent it raises the revenue requirement (which Mr. McLeod testified is a possibility),[279] I recommend that rates be capped at/ the revenue requirement of $373,214,000, which is the amount that was noticed to the public in this case. Such capping is a typical Commission practice.[280]

If the Commission believes more process is needed to address the Clover and/or Biomass Adjustments, the Commission could issue an interim order remanding the case for the limited purpose of taking additional evidence on the adjustment(s). The case participants likely would not have much time for discovery, but at a minimum, they could have a short window to review the filing, after which a hearing could be held and another Report submitted addressing these limited issues.

---

[275] The Company seems to have been aware of the biomass issue since February 2023 and so has had a fair amount of time to consider how the Biomass Adjustment would affect rates. *See* Exhibit Nos. 10 (ER-PE-7) and 10(C) (ER-PE-7). These are responses to interrogatories that Dominion received February 7, 2023. According to the Order for Notice and Hearing in this case (at page 15), the Company had seven calendar days to respond to interrogatories.
[276] Tr. at 88-89, 212 (McLeod). *See also* revisions to Code § 56-585.1 A 3 made through 2023 Va. Acts ch. 757 ("After 2021, each Phase II Utility shall make a biennial filing by March 31 of every second year, except that the 2023 filing for a Phase II utility shall be made on or after July 1, 2023.").
[277] Tr. at 88-89 (McLeod).
[278] *Compare* Tr. at 93 *with* tr. at 212 (McLeod).
[279] *Id.* at 212.
[280] *See, e.g., Petition of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00013, 2021 S.C.C. Ann. Rep. 390, 391, Final Order (Sept. 3, 2021) (finding "that a revenue requirement of $68,339,000 is reasonable; however, recovery in this case shall be limited to the originally filed and noticed amount of $67,451,000. . ..").

Alternatively, to the extent the Commission disagrees with my analysis of what costs are "necessary to comply" with environmental laws or regulations, and/or believes that Code § 56-585.1 A 5 e permits the Biomass and Clover Adjustments to be made through a true-up instead of being made now, the Commission could adopt the revenue requirement of approximately $356.6 million as calculated by Staff and agreed to by the Company.

Projected and Actual Allowance Prices

APV questioned the price of allowances Dominion used in this case compared to the $12.50 clearing price of allowances in RGGI Auction 59, which occurred in March 2023.[281] The Company assumed a price of $13.52 per allowance,[282] which is a weighted average of the cost of emissions Dominion estimated it would need for October through December 2022 ($12.92 per allowance) and for January through December 2023 ($13.66 per allowance).[283] The record in this case supports a finding that the projected and actual allowance prices that form the basis of Rider RGGI are reasonable for purposes of this case. There was testimony that the $13.52 weighted average price per allowance is based on ICE futures contracts for December of 2022 and 2023, that the December contracts are the most liquid, and that ICE is "the most widely used" exchange for allowances.[284] The use of weighted averages to calculate the cost of allowances also is consistent with the Company's practice in the Initial Rider RGGI Case.[285] Staff also reviewed the Company's methodology to estimate CO_2 allowance prices and concluded that the short-term forecasts of allowance prices appear reasonable.[286] I find that the Company's use of ICE forward market prices is reasonable.

Revenue Requirement, Cost Allocation, and Rate Design

<u>Revenue Requirement</u>. The Petition requests a Rider RGGI revenue requirement of $373,214,000.[287] Staff recalculated the revenue requirement using actual carbon emissions as the foundation for allowance requirements, using three additional months of actual emissions data, and additional auction purchase data.[288] Staff computed a Rider RGGI revenue requirement of $356,581,248, which is $16,632,786 lower than that of the Company.[289] The

---

[281] Tr. at 71 (Holmes cross of Matzen).
[282] Exhibit No. 3 (Hitch Direct) at 8.
[283] Exhibit No. 9 (Matzen Direct) at 3-4 and Schedule 1.
[284] *Id.* at 3-4 and Schedule 1; Tr. at 75 (Matzen) (noting, in regard to ICE, that "[t]here's a December contract for each year. It's the most liquid contract, has the most activity, and that's why it tends to be the best price.").
[285] *Initial Rider RGGI Final Order,* 2021 S.C.C. Ann. Rep. at 274.
[286] Exhibit No. 24 (Pratt Direct) at 7 and Attachment TM-1.
[287] Exhibit No. 2 (Petition) at 7.
[288] Exhibit No. 21 (Harris Direct) at 4.
[289] *Id.* at 3.

Company accepted this revised revenue requirement.[290] As noted above, I find that the record in this case supports a finding that a revenue requirement based on Staff's recalculations, accepted by the Company, if also modified for the Clover and Biomass Adjustments, is necessary, reasonable, and prudent. If the Commission disagrees with my analysis as to those adjustments, the Commission could approve a revenue requirement of $356,581,248 as necessary, reasonable, and prudent.

<u>Capital Structure</u>. The Company used its actual capital structure and year-end cost of capital as of December 31, 2021, for rate-setting purposes in this case, including a 6.833% WACC and a 9.35% ROE.[291] Staff agreed.[292] Additionally, the Company proposed to use the following capital structures for deferred costs,[293] which were recommended by Staff for use in this case:[294]

Time Period	Capital Structure	WACC	ROE
Sept. 1 – Dec. 31, 2020	As of Dec. 31, 2020	6.806%	9.200%
Jan. 1 – Nov. 17, 2021	As of Dec. 31, 2021	6.744%	9.200%
Nov. 18 – Dec. 31, 2021	As of Dec. 31, 2021	6.833%	9.350%

The record supports a finding that these capital structure proposals, for both deferred costs and the Projected Cost Recovery Factor, are reasonable. I recommend they be approved for use in this Rider RGGI.

<u>Cost Allocation/ Rate Design</u>. The Company proposed to allocate Rider RGGI costs on the basis of customers' energy consumption, through a uniform per-kWh charge applicable to all customers taking generation services from Dominion in its Virginia jurisdiction, which methodology was approved in the *Initial Rider RGGI Final Order*.[295] Since the North Carolina Utilities Commission ruled that the Company should not recover RGGI costs from its North

---

[290] Exhibit No. 12 (McLeod Direct) at 2. Typically, a rider includes a Projected Cost Recovery Factor and an Actual Cost True-Up Factor. There is no Actual Cost True-Up Factor in this case; thus, the revenue requirement consists entirely of the Projected Cost Recovery Factor, which is approximately $356.6 million, incorporating Staff's changes. *See id.* at 6 and Schedule 1; Exhibit No. 21 (Harris Direct) at Schedule 1.
[291] Exhibit No. 12 (McLeod Direct) at 6 and Schedule 1 page 17. The 9.35% ROE was authorized by the Commission in the *2021 Triennial Order*. Further, the Company represents that the capital structure used to develop the revenue requirement "reflects the methodology proposed by Staff and approved by the Commission in that Final Order." Exhibit No. 12 (McLeod Direct) at 5.
[292] Exhibit No. 23 (Elmes Direct) at Summary Page.
[293] See Exhibit No. 12 (McLeod Direct) at 5 and Schedule 1 pages 15-17.
[294] Exhibit No. 23 (Elmes Direct) at Summary Page, Schedule 1, Schedule 2 page 1, and Schedule 3 page 1. Staff reviewed the capital structure and noted two minor discrepancies between the Company's and Staff's calculation of short-term debt, which Staff stated have a negligible impact on the WACC beyond three decimal places. *Id.* at 3.
[295] Exhibit No. 14 (Givens Direct) at 2-4. *See also Initial Rider RGGI Final Order*, 2021 S.C.C. Ann. Rep. at 274, 277.

Carolina ratepayers, Company witness Givens calculated allocation factors to allocate RGGI costs to only Virginia jurisdictional customers.[296]

Mr. Givens also developed the allocation factors on a monthly basis.[297] Staff reviewed this proposal, explaining that in the Initial Rider RGGI Case, the Company used an annual allocation factor developed on forecasted total system energy usage estimated to occur in the rate year at issue in that case.[298] In this case, Dominion has proposed to use monthly allocation factors based on: (i) actual usage for January 2021 through September 2022; and (ii) forecasted usage for October 2022 through August 2024.[299] According to Mr. Givens, a monthly allocation factor better aligns with the Company's allocation methodology for fuel costs, which also is a monthly factor. The Company asserts that RGGI costs and fuel costs have similar cost causation and, accordingly, should be allocated the same way.[300]

Staff opposes neither the proposal to calculate allocation factors on a monthly basis nor the Company's removal of North Carolina jurisdictional load for purposes of developing jurisdictional allocation factors.[301] Consumer Counsel noted "that under the current state of things[,] Virginians are being asked to pay for . . . carbon allowances associated with North Carolina. And the more transparency around that issue . . . the better in the view of Consumer Counsel's mind."[302] The record of this case supports findings that Mr. Givens' proposed cost allocations and rate design are reasonable; I recommend the Commission approve them for use in this case, provided that updates are made as needed for the Clover and Biomass Adjustments.

Other Considerations

VCHEC Biomass Requirement Documentation. APV witness Abbott recommended that Dominion be required to document decisions associated with operating the VCHEC facility in must-run dispatch status to comply with the facility's biomass permitting requirement, and to provide such documentation and analysis.[303] In keeping with the *2022 Fuel Order* and the Commission's Order in Case No. PUR-2021-00114, the Company already is required to keep records of the dispatch decisions for all its coal facilities.[304] Exhibit No. 28 in this case record also reflects that the Company keeps detailed records as to which coal generating units

---

[296] Exhibit No. 14 (Givens Direct) at 3. *See also In the Matter of Petition of Dominion Energy North Carolina for a Declaratory Ruling*, Docket No. E-22, Sub 601, Order on Petition for Declaratory Ruling (N.C.U.C. Sept. 29, 2021).
[297] Exhibit No. 14 (Givens Direct) at 3.
[298] Exhibit No. 24 (Pratt Direct) at 11.
[299] Exhibit No. 14 (Givens Direct) at 3 and Schedule 1.
[300] Exhibit No. 24 (Pratt Direct) at 11 and Attachment TM-2.
[301] *Id.* at 11-13.
[302] Tr. at 257 (Burton).
[303] Exhibit No. 16 (Abbott Direct) at 23.
[304] *2022 Fuel Order* at 7 n.20; *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider S, Virginia City Hybrid Energy Center, for the rate years commencing April 1, 2022, and April 1, 2023*, Case No. PUR-2021-00114, Doc. Con. Cen. No. 220220032, Final Order (Feb. 8, 2022).

(including VCHEC) it self-schedules, the dates and hours of self-scheduling, the reasons for self-scheduling, and the daily energy margin associated with the self-scheduling events.[305] Thus, the Company already documents decisions associated with operating VCHEC in must-run dispatch status. Out of abundance of caution, however, I recommend that to the extent that a reason for self-scheduling VCHEC relates to compliance with biomass permitting requirements, the Commission should require the Company to note such reasons in its self-scheduling records, if it does not already do so.

Dispatch Analysis. Mr. Abbott also recommended that in future Rider RGGI cases, the Company perform an analysis similar to the one he performed for August 2022 through January 2023. He suggested the Company's analysis start with February 2023 and determine RGGI costs related to uneconomic must-run dispatch for its coal fleet.[306] Based on the record of this case, and my previous discussion on APV's self-scheduling analysis, I recommend that the Commission not require the Company to perform such analysis.

Impact on Customers. With or without the Biomass and Clover Adjustments, it appears that rates ultimately set in this case may be significant for customers. I note that the revenue requirement being recommended herein is based on 17 months of costs (those incurred between August 2022 and December 2023), to be recovered over a 12-month period (September 2023 through August 2024). Should Virginia exit RGGI at the end of 2023, the only RGGI-related costs that should remain after the Rate Year are true-up costs (or refunds) related to calendar years 2022 and 2023. Should Virginia continue to participate in RGGI beyond 2023, I anticipate that future Rider RGGI cases would include a Projected Cost Recovery Factor based on something much closer to twelve (not seventeen) months of costs.

To this end I recommend that the Commission require Dominion to file a Rider RGGI update in 2023 or as soon as possible in 2024:[307] (i) to true-up RGGI-related recovery with actual RGGI costs for 2022; and (ii) if Virginia remains in RGGI, to propose a Projected Cost Recovery Factor based on just twelve months of costs, or as few months beyond twelve as possible.

---

[305] Exhibit No. 28 (DEV-PE-1). These self-scheduling records appear to be similar to the records the Commission has required Appalachian Power Company to keep for its Clinch River facility. *See Petition of Appalachian Power Company, For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2022-00001, Doc. Con. Cen. No. 221130018, Final Order at 3 (Nov. 21, 2022) (directing this utility, "each time it self-schedules Clinch River, to record the hours of each day that Clinch River self-schedules, the associated megawatts that are self-scheduled, and the reason for each self-scheduling.").
[306] Exhibit No. 16 (Abbott Direct) at 24.
[307] Tr. at 100-101 (McLeod) (stating that the Company may not have sufficient data to true-up 2022 costs in a 2023 filing). It is unclear from the record whether the Company plans a 2023 Rider RGGI filing.

FINDINGS AND RECOMMENDATIONS

Based on the evidence received in this case and the applicable law, I **DIRECT** Dominion to make a compliance filing, to be filed with its comments to this Report, incorporating the Biomass and Clover Adjustments. Such compliance filing should include adjusted Rider RGGI rates and accompanying workpapers that include the recalculation of expense, re-amortization of allowances, and re-computation of rate base and revenue requirement, with associated cost allocation and rate design documentation. Commission Staff should verify these calculations as soon as possible after the compliance filing is made. Additionally, I **FIND** that:

1. As to proposed Self-Scheduling Adjustments 1 and 2, APV's self-scheduling analysis and proffered cost disallowances related to uneconomic dispatch, on an hourly or 24-hour basis, of Dominion's coal units over the period August 1, 2022, through January 31, 2023:
   - are inconsistent with the *2022 Fuel Order*;
   - ask the Commission to judge prudence not on the circumstances at the time a decision is made but instead based on after-the-fact determinations; and
   - misconstrue Dominion's strategy to comply with its DEQ biomass permit for VCHEC;

2. As to the proposed Over-Forecast Adjustment, under the circumstances of this case, updating the revenue requirement to reflect actual, not forecasted, emissions data for the first quarter of 2023 is not reasonable or prudent at this time;

3. As to the proposed Clover and Biomass Adjustments, the cost to purchase allowances to cover ODEC's share of emissions from the Clover facility and the cost to purchase allowances to cover emissions related to start-up power at Dominion's biomass plants are not "necessary" for Dominion "to comply" with RGGI pursuant to Code § 56-585.1 A 5 e;

4. With the condition that the Biomass and Clover Adjustment are made, the projected and actual Rider RGGI costs as proposed in the Petition and updated by Commission Staff are "necessary" for Dominion "to comply with state or federal environmental laws or regulations" pursuant to Code § 56-585.1 A 5 e and are reasonable and prudent pursuant to Code § 56-585.1 D;

5. The Rider RGGI revenue requirement of approximately $356.6 million, once modified for the Clover and Biomass Adjustments, is necessary, reasonable, and prudent;

6. To the extent the Commission disagrees with the analysis in this Report of what costs are "necessary" for Dominion "to comply" with environmental laws or regulations, and/or believes that Code § 56-585.1 A 5 e permits the Biomass and Clover Adjustments to be made through a true-up instead of being made now, the Commission could adopt the revenue requirement of approximately $356.6 million as calculated by Staff and agreed to by the Company;

7. If the Commission believes more process is needed to address the Clover and/or Biomass Adjustments, the Commission could issue an interim order remanding the case for the limited purpose of taking additional evidence thereon;

8. The projected and actual allowance prices that form the basis of Rider RGGI (a weighted average of allowance costs of $12.92 each for October through December 2022 and $13.66 each for January through December 2023) are reasonable for purposes of this case;

9. The capital structure proposals for both deferred costs and the Projected Cost Recovery Factor are reasonable; and

10. The Company's proposed cost allocations and rate design are reasonable, including the calculation of allocation factors on a monthly basis and the allocation of RGGI costs only to Virginia jurisdictional customers, provided that updates are made as needed for the Clover and Biomass Adjustments.

Accordingly, **I RECOMMEND** the Commission enter an Order that:

1. ***ADOPTS*** the findings and recommendations of this Report;

2. ***REJECTS*** Self-Scheduling Adjustments 1 and 2 and the Over-Forecast Adjustment;

3. ***APPROVES*** a Rider RGGI revenue requirement of $356.6 million, as further modified for the Clover and Biomass Adjustments;

4. ***CAPS*** any adjustment to the revenue requirement based on the Biomass and Clover Adjustments at $373,214,000, which is the amount that was requested in the Petition and noticed to the public in this case;

5. ***APPROVES*** the capital structure proposals for both deferred costs and the Projected Cost Recovery Factor;

6. ***APPROVES*** the Company's proposed cost allocations and rate design for use in this case, provided that updates are made as needed for the Clover and Biomass Adjustments;

7. ***REINSTATES*** Rider RGGI effective for the Rate Year beginning September 1, 2023;

8. ***REQUIRES*** the Company, if it does not already do so, to note in its self-scheduling records those occasions in which a reason for self-scheduling VCHEC relates to compliance with biomass permitting requirements;

9. ***REQUIRES*** Dominion to file a Rider RGGI update in 2023 or as soon as possible in 2024: (i) to true-up RGGI-related recovery with actual RGGI costs for 2022; and (ii) if Virginia remains in RGGI, to propose a Projected Cost Recovery Factor based on just twelve months of costs, or as few months beyond twelve as possible; and

10. ***CONTINUES*** this case to the extent necessary for further process related to the Clover and/or Biomass Adjustments.

COMMENTS

The parties are advised that, pursuant to Rule 5 VAC 5-20-120 C of the Commission's Rules of Practice and Procedure ("Rules of Practice") and Code § 12.1-31, any comments to this Report, and the Company's compliance filing, must be filed on or before June 16, 2023. To promote administrative efficiency, the parties are encouraged to file electronically in accordance with 5 VAC 5-20-140 of the Rules of Practice. If not filed electronically, an original and fifteen (15) copies of the comments must be submitted in writing to the Clerk of the Commission c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218. Any party filing such comments shall attach a certificate to the foot of such document certifying that copies have been served by electronic mail to all counsel of record and any such party not represented by counsel.

Respectfully submitted,

M. Renae Carter

M. Renae Carter
Hearing Examiner

The Clerk's Office Document Control Center is requested to send a copy of the above Report to all persons on the official Service List in this matter. The Service List is available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, First Floor, Tyler Building, Richmond, Virginia 23219.