COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

PETITION OF

VIRGINIA ELECTRIC AND POWER COMPANY **CASE NO. PUR-2023-00142**

For approval of its 2023 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia and related requests

REPORT OF D. MATHIAS ROUSSY, JR., HEARING EXAMINER (PUBLIC VERSION)

February 15, 2024

Legislation enacted in 2020 created a mandatory renewable portfolio standard ("RPS") for the Commonwealth and directed Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("Dominion" or "Company") to file annually with the State Corporation Commission ("Commission") a plan for meeting the Commonwealth's RPS requirements. These plans must be filed annually, together with any associated requests for solar, wind, or storage construction and cost recovery.

In the three prior RPS plan cases, the Commission approved Dominion's general RPS development plans and approved, among other things, specific proposals to: (1) construct and recover the costs for 1,227 megawatts ("MW") of solar projects and 86 MW of storage projects that Dominion will own; and (2) enter power purchase agreements for 882 MW of solar and 82 MW of storage.[1]

This case involves Dominion's fourth RPS plan filing, which proposes to: (1) construct and/or recover the costs of an additional 337 MW of solar projects that Dominion would own, with an estimated total capital cost of $867 million, excluding financing costs; and (2) enter power purchase agreements for an additional 435 MW of solar.

The record of this case indicates that the costs of solar resources developed and procured by Dominion remain at or above the elevated levels seen in last year's RPS plan case, notwithstanding beneficial federal tax credits. Based on Dominion's need for renewable energy certificates required by the Commonwealth's RPS and its need for energy, I recommend the Commission approve all 435 MW of proposed solar agreements and 329 MW of solar projects Dominion proposes to own and operate. While the record also identifies Dominion's need for capacity, I do not find that these resources would provide cost-effective capacity, nor would they provide capacity on the scale needed to meet the unprecedented level of projected demand from data center growth or the significant generation retirements scheduled by the 2020 law.

For the 8 MW of solar projects I recommend be denied, the record demonstrates that Dominion's ratepayers would be far better off if Dominion pursued alternative options. Dominion's evidence indicates that the estimated negative value to its ratepayers of these

[1] The Commission has also approved the construction and/or cost recovery for other renewable resources outside of RPS plan cases – most notably, the 2,587 MW Coastal Virginia Offshore Wind Commercial Project.

proposed projects is between two and four times greater than the positive value these projects would provide the world from reduced carbon emissions. However, the record could support approval of these two projects if the Commission gives less weight to the economic analysis and/or more weight to other relevant considerations. Alternatively, the record could also support denial of more projects or agreements proposed by Dominion if the Commission assigns greater weight to certain economic analysis in this case.

Dominion's filing also proposes to update Rider CE, the existing rate adjustment clause used to recover costs of Dominion's approved RPS projects. Dominion proposes to expand Rider CE by consolidating it with another rate adjustment clause, Rider PPA, which currently recovers the costs of solar and storage purchase power agreements approved by the Commission. Dominion's filing proposes a $136.7 million consolidated revenue requirement, which would increase the collective monthly charge for these two riders from $1.41 to $2.95, for a residential customer using 1,000 kilowatt-hours per month.[2] I recommend a $133.3 million consolidated revenue requirement, which incorporates corrections agreed to by Dominion and also excludes cost recovery for the 8 MW of expensive solar projects I recommend the Commission deny.

Dominion's general plan for the development of new solar, wind, and energy storage resources appears to be a reasonable planning document, recognizing that specific projects and agreements will be proposed for construction or cost recovery in future proceedings. However, given the elevated costs of solar projects and agreements shown in this case, I recommend that Dominion expand its existing RPS procurement process to accept bids for unbundled renewable energy certificates.

Dominion's filing also includes the Company's RPS compliance report for 2022. While certain issues can be addressed in the instant proceeding, and recommendations on such issues are included herein, Dominion's compliance obligation cannot be finalized until open issues are addressed in a separate Commission proceeding.

[2] For such customers, Rider CE is currently a monthly charge of $1.70, while Rider PPA is currently a monthly credit of $0.29. These two rate adjustment clauses only recover some of the costs of RPS compliance.

Table of Contents

HISTORY OF THE CASE

The Virginia Clean Economy Act ("VCEA") was enacted during the 2020 General Assembly Session.[3] The VCEA, among other things, established in the Code of Virginia ("Code") a mandatory renewable energy portfolio standard program ("RPS Program") for Dominion.[4] In connection with the statutory RPS requirements, Dominion must file with the Commission annual plans and petitions for approval of new solar and onshore wind generation capacity.[5] Such annual filings must also include Dominion's plan to meet energy storage project targets set by the VCEA.[6]

On October 3, 2023, Dominion submitted its annual RPS filing[7] for 2023 ("Petition").[8] The Petition requests, among other things, that the Commission:[9]

> (1) Approve the Company's annual plan for the development of new solar, onshore wind, and energy storage resources ("RPS Development Plan") in connection with the mandatory RPS Program pursuant to Code § 56-585.5 D 4;
>
> (2) Grant certificates of public convenience and necessity ("CPCNs") and approval to construct and operate four utility-scale projects totaling approximately 329 MW of solar pursuant to Code § 56-580 D;
>
> (3) Approve to recover, through the existing Rider CE rate adjustment clause, the costs of (a) the four utility-scale solar projects for which the Petition seeks CPCNs, one 5 MW solar facility (collectively, the "CE-4 Projects"), and related interconnection facilities; and (b) one 3 MW distributed solar project and related interconnection facilities ("CE-4 Distributed Solar Project" or "Alberta") pursuant to Code § 56-585.1 A 6;
>
> (4) Approve an update to Rider CE for cost recovery associated with solar projects and related interconnection facilities approved by the Commission in prior annual RPS plan proceedings;
>
> (5) Make a prudence determination for Dominion to enter into 13 power purchase agreements ("PPAs") for resources totaling approximately 435 MW of solar ("CE-4 PPAs" or "CE-4 Distributed Solar PPAs," as applicable) pursuant to Code § 56-585.1:4;

---

[3] 2020 Va. Acts chs. 1193, 1194.

[4] Code § 56-585.5. Appalachian Power Company ("APCo") is also subject to a mandatory RPS Program.

[5] Code § 56-585.5 D 4.

[6] *Id.*

[7] On November 9 and December 21, 2023, Dominion filed errata to this initial filing.

[8] Dominion filed its Petition in a public version and an extraordinarily sensitive version. Concurrent with its Petition, Dominion filed a Motion for Entry of a Protective Order and Additional Protective Treatment. A Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information was entered on October 17, 2023.

[9] *See, e.g.*, Exhibit ("Ex.") 3 (Petition) at 1-2. When cited in footnotes, "Petition" refers specifically to the legal petition filed as part of the initial 2023 RPS plan filing on October 3, 2023. When referenced in the body of the Report, "Petition" may refer more broadly to the 2023 RPS plan filing package.

(6) Approve cost recovery, through Rider CE, for the CE-4 PPAs and CE-4 Distributed Solar PPAs pursuant to Code § 56-585.1 A 5; and

(7) Approve the consolidation of Rider CE and Rider PPA pursuant to Code § 56-585.1 A 7, resulting in (a) cost recovery associated with the CE-1, CE-2, and CE-3 PPAs through Rider CE and (b) the end of Rider PPA as of April 30, 2024.

On October 16, 2023, the Commission issued an Order for Notice and Hearing ("Procedural Order") that, among other things, directed the Company to provide notice of its Petition; directed the Commission's Staff ("Staff") to investigate the Petition and file testimony and exhibits containing Staff's findings and recommendations; established a procedural schedule, including a hearing to receive telephonic public witness testimony and to receive the evidence of the parties and Staff; provided opportunities for interested persons to intervene and participate; and assigned a Hearing Examiner to conduct all further proceedings in this case and to file a final report containing findings and recommendations.[10]

On November 20, 2023, Dominion filed a Motion for an Extension of Time to Respond to the DEQ Report and for Expedited Consideration ("Rebuttal Motion"). In its Rebuttal Motion, Dominion requested that it be allowed to file rebuttal testimony in response to the DEQ Report by seven business days following the filing of the DEQ Report.

On November 21, 2023, Dominion filed proof of notice and service.[11]

On November 27, 2023, a Hearing Examiner's Ruling granted the Rebuttal Motion.

On November 27, 2023, Dominion filed a Motion for Leave to File Supplemental Direct Testimony ("Supplemental Testimony Motion").

On December 14, 2023, the Department of Environmental Quality ("DEQ") filed the results of a coordinated review of three of the proposed CE-4 Projects by various agencies ("DEQ Report").[12] The DEQ Report included a Wetland Impact Consultation provided by DEQ's Office of Wetlands and Stream Protection.

On December 29, 2023, a Hearing Examiner's Ruling granted Dominion's Supplemental Testimony Motion.

Notices of participation were filed in this case by Appalachian Voices; the Virginia Committee for Fair Utility Rates ("Committee"); and the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel").

---

[10] This case was docketed on August 29, 2023, by the Commission's Order on Waiver Requests, which granted in part Dominion's Motion for Limited Waivers of Commission Rules filed on August 8, 2023.

[11] At the hearing, proof of notice and service was admitted into the record as Exhibit 1.

[12] Ex. 42.

On January 10 and 11, 2024, the hearing was convened, as scheduled, in the Commission's courtroom.[13] Elaine S. Ryan, Esquire, Sarah Bennett Bures, Esquire, Katherine C. Creef, Esquire, and Lisa R. Crabtree, Esquire, appeared on behalf of Dominion. Grayson Holmes, Esquire, and Rachel James, Esquire, appeared on behalf of Appalachian Voices. John E. Farmer, Jr., Esquire, and Carew S. Bartley, Esquire, appeared on behalf of Consumer Counsel. K. Beth Clowers, Esquire, Frederick D. Ochsenhirt, Esquire, Andrew F. Major, Esquire, and Simeon Brown, Esquire, appeared on behalf of Staff. The hearing concluded with closing arguments by counsel.

One member of the public filed two sets of written comments and also testified as a public witness at the hearing.

PUBLIC COMMENTS

David Tucker, a Smithfield resident, filed two sets of comments. In his initial comments, Mr. Tucker provided pictures of panels from Dominion's operational Woodland solar facility to document arrays that are out of sync with each other. He offered quantitative estimates of daily generation lost at this facility, and an associated cost estimate. He compared the capacity factors for 2016-2021 that Dominion reported in this year's Petition to the same information reported in last year's petition. He pointed out that most of these reported figures changed.[14]

Mr. Tucker compiled and provided solar output figures Dominion reported to the U.S. Energy Information Administration ("EIA"). According to Mr. Tucker, whether a respondent reports such data to EIA annually or monthly can produce different capacity factor calculations. He expressed concern that annual production amounts, when converted to monthly amounts, result in unrealistic capacity factor changes from month to month.

Mr. Tucker's second set of comments was included as part of an exhibit that was admitted during his public witness testimony, and therefore is discussed as part of the Summary of the Record below.

SUMMARY OF THE RECORD

Public Witness Testimony

David Tucker described his background as a professional engineer who retired from Dominion's Surry Nuclear Power Station, after 38 years of working in Fossil and Hydro, and Nuclear Engineering. In the 1980s, he gained experience on heat rate, capacity factor, and efficiencies, as Dominion was required by the Commission to identify and correct wasted British thermal units in fossil generation. He described the results of this work as positive in that heat

[13] The Committee did not participate in the hearing.
[14] Dominion witness Prideaux testified that historic capacity factor values changed from last year's case to this year's because Dominion discovered errors in the capacity factor calculations reported last year. Tr. at 165 (Prideaux).

rates dropped and capacity factors increased.[15] He expressed concern that today, Dominion "is not treating solar energy as precious ... as it did with" fossil-fueled energy when mandated to do so in the 1980s by the Commission.[16]

Mr. Tucker testified as a concerned ratepayer. He questioned how ratepayers can tolerate a 120% rate increase by 2035 supporting the RPS when solar capacity factors are decreasing beyond temperature and age coefficients.[17] He thinks solar energy is great, but cautioned that if it is not managed correctly, it will require more land and more cost.[18]

Mr. Tucker asked the Commission not to accept Dominion's 2023 RPS Development Plan. He elaborated further on his concerns about Dominion's reported solar capacity factors, which he indicated are decreasing, due to neglect, beyond acceptable age and temperature coefficients, regardless of the source for capacity factor information.[19]

Mr. Tucker offered into evidence some of his pictures of panels from Dominion's Woodland solar facility that are out of sync with each other.[20] He offered quantitative estimates of daily generation lost at this facility, and an associated cost estimate he calculated. He described his cost estimate as alarming.[21]

Mr. Tucker calculated and provided capacity factors using EIA data reported by Dominion and the nameplate capacity of Dominion solar facilities. He concluded that the capacity factors reported in the 2023 RPS Development Plan do not trend with those he calculated using Dominion's EIA data.[22] He observed that only a few of the 34 facilities for which he pulled EIA data reported by Dominion or its affiliates have a capacity factor of at least 22%. For the 34 facilities, he calculated average capacity factors of 21.87% and 20.55% for 2021 and 2022, respectively. He calculated that the decrease in capacity factor equates to approximately 13,700 fewer homes served.[23] He observed that two fixed tilt facilities are achieving 22% capacity factors even though they are not tracking the sun.[24]

Regarding his concern about annual reporting of solar energy production to EIA, Mr. Tucker asserted that monthly amounts are likely being "manipulated" through mathematical weighting to create identical month to month capacity factors percentage differences on the yearly basis.[25] He wants Dominion to report monthly, which he believes would provide better

---

[15] Tr. at 15-16 (Tucker).

[16] Tr. at 16 (Tucker). Mr. Tucker appeared to be referencing monthly reports provided pursuant to Code § 56-249.3, which was enacted in the late 1970s.

[17] Tr. at 15-16 (Tucker). Ex. 2 at second document, p. 12 of 30.

[18] Tr. at 37 (Tucker).

[19] *See, e.g.*, Ex. 2 at second document, p. 1 of 30.

[20] Ex. 2 at second document, pp. 19-27 of 30.

[21] Tr. at 19 (Tucker).

[22] *See, e.g.*, Ex. 2 at second document, pp. 1, 11 of 30. In calculating capacity factors, Mr. Tucker appears to use the nominal capacity of a facility to calculate its maximum output. Dominion witness Prideaux indicated that Dominion uses the nominal capacity, degraded by 0.25% in the first year of operations and 0.5% for every year thereafter. Tr. at 166-67 (Prideaux).

[23] *See, e.g.*, Ex. 2 at second document, pp. 1, 16-17 of 30.

[24] Tr. at 32 (Tucker).

[25] Ex. 2 at first document, p. 9 of 12, second document, pp. 13-15 of 30; Tr. at 26-29 (Tucker).

visibility. He believes that monthly data would give Dominion the opportunity to respond and make timely corrections, instead of waiting a full year to identify a problem at a facility.[26]

Mr. Tucker provided calculations and various illustrations of how much land solar generation requires compared to fossil-fueled generation.[27] In addition, based on data from PJM Interconnection, LLC ("PJM"), he indicated that solar projects in the PJM queue for interconnection in Isle of Wight County would require nearly 8% of all the land in Isle of Wight County.[28]

2023 RPS Development Plan

Dominion's 2023 RPS Development Plan identifies Dominion's progress toward meeting the VCEA's solar and onshore wind development targets. Dominion has constructed or purchased approximately 3,744 MW of such nameplate capacity, as of August 31, 2023.[29] The Company presented the following near-term (through 2024) and longer-term (through 2035) plan targets for utility-scale solar and onshore wind and distributed solar.[30]

Solar and Onshore Wind Development Plan Through 2024 (in MW)

	Other	2020	2021	2022	2023	2024	Total
Utility-Scale	**863.8**	**497.5**	**823.9**	**727.6**	**754.2**	**720.0**	**4,387.0**
Company-Owned System	396.4	82.0	661.0	474.0	334.0	594.0	2,541.4
Company-Owned Ring-Fenced[2]	347.4						347.4
PPA	120.0	415.5	162.9	253.6	420.3	126.0	1,498.3
Distributed Solar	-	-	**36.6**	**22.0**	**18.0**	**19.0**	**95.6**
Company-Owned System	-	-	3.6	6.0	3.0	10.0	22.6
PPA	-	-	33.0	16.0	15.0	9.0	73.0
Total	**863.8**	**497.5**	**860.5**	**749.6**	**772.2**	**739.0**	**4,482.6**
Company-Owned System	396.4	82.0	664.6	480.0	337.0	604.0	2,564.0
Company-Owned Ring-Fenced[2]	347.4						347.4
PPA	120.0	415.5	195.9	269.6	435.3	135.0	1,571.3

Utility-Scale Solar and Onshore Wind Development Plan Through 2035 (in MW)

	Prior Years	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total	%
Total	**4,387**	**786**	**793**	**793**	**771**	**771**	**771**	**774**	**774**	**774**	**774**	**860**	**13,028**	**100**
Company-Owned	2,889	514	514	514	494	494	494	503	503	503	503	560	8,484	65
PPA	1,498	272	279	279	277	277	277	271	271	271	271	301	4,544	35

---

[26] Tr. at 29-30 (Tucker).

[27] Ex. 2 at first document, p. 12 of 12; Tr. at 35-36 (Tucker).

[28] Ex. 2 at first document, p. 11 of 12; Tr. at 34 (Tucker).

[29] Ex. 4 (2023 RPS Development Plan) at 4. Of this amount, approximately 77 MW qualify as distributed solar under the VCEA. *Id.*

[30] *Id.* at 5-6 (footnotes omitted). For all three tables, the values for each year represent amounts of generation and PPAs that Dominion has petitioned for approval since the passage of the VCEA or that Dominion expects to petition for approval in future filings. *Id.* For the first table, values in the "Other" column represent other generation capacity that Dominion has counted toward the development targets that were placed into service after January 1, 2015, but before passage of the VCEA. *Id.* at 5. Company-owned resources include ring-fenced facilities not under contract with an accelerated renewable energy buyer. *Id.* at 5-6. For the longer-term tables provided in this section of the Report, fractions are rounded.

Distributed Solar Development Plan Through 2035 (in MW)

	Prior Years	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total	%
Total	**96**	**33**	**51**	**66**	**84**	**97**	**106**	**109**	**109**	**112**	**117**	**120**	**1,100**	**100**
Company-Owned	23	24	36	45	57	66	72	75	75	78	81	83	715	65
PPA	73	9	15	21	27	31	34	34	34	34	36	37	385	35

The Company reported that, based on information known as of June 30, 2023, certified accelerated renewable energy buyers ("ARBs") have approximately 1,972 MW of solar or onshore wind generation resources under contract. Pursuant to Code § 56-585.5 G, Dominion indicated that this capacity will offset the 16,100 MW statutory target for solar and wind development, resulting in a revised development target of 14,128 MW.[31]

For energy storage, the Company presented the following near-term (2021 through 2024) and longer-term (through 2035) plan targets.[32]

Energy Storage Through 2025 (MW)

	2020	2021	2022	2023	2024	2025	Total
Total	-	**103**	**65**	-	**115**	**105**	**388**
Company-Owned	-	70	16	-	65	75	226
PPA	-	33	49	-	50	30	162

Energy Storage Through 2035 (MW)

	Prior Years	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total	%
Total	**388**	**130**	**160**	**170**	**190**	**240**	**250**	**270**	**290**	**300**	**312**	**2,700**	**100**
Company-Owned	226	90	120	130	130	150	150	170	190	200	200	1,756	65
PPA	162	40	40	40	60	90	100	100	100	100	112	944	35

The 2023 RPS Development Plan discussed requests for proposals ("RFPs") for applicable resources. Beginning in 2022, these RFPs were distinguished by ownership arrangement – one RFP process for development proposals by storage, wind, and solar, including utility-scale and distributed solar resources and a separate RFP process covering PPA proposals for all such resources. Also in 2022, Dominion allowed development proposals to be continually submitted. On April 6, 2023, Dominion completed a refresh of the April 29, 2022 RFP for development proposals ("Development RFP"). On September 1, 2022, Dominion issued an RFP for PPAs, with bids due February 1, 2023 ("2022 PPA RFP").[33]

---

[31] *Id.* at 5. *See also* Exs. 4, 4-ES (2023 RPS Development Plan) at Attachment 5 (providing information on ARBs).

[32] Ex. 4 (2023 RPS Development Plan) at 8. The values shown by year reflect the generation capacity Dominion has petitioned the Commission for approval since the passage of the VCEA or that Dominion expects to petition for approval in future filings. These figures exclude the 12 MW of storage petitioned for under the Grid Transformation and Security Act ("GTSA") battery pilot program in Case No. PUR-2023-00162, the non-wires alternative pilot approved in Case No. PUR-2023-00051, and the 16 MW in-service through the GTSA battery pilot program and the battery to be installed as part of the Locks Campus Microgrid. *Id.* Fractions are rounded.

[33] *Id.* at 6-7. *See also* Exs. 9, 10-ES at Filing Sched. 46A, Statement 3 (report on the Development RFP), Filing Sched. 46B, Statement 1 (report on the 2022 PPA RFP).

Dominion's 2023 RPS Development Plan discussed the integrated resource plan ("IRP") modeling assumptions[34] and results presented in the 2023 IRP.[35] Dominion instructed its model to select solar and energy storage resources consistent with the 2022 RPS Development Plan for Alternative Plans B and D. In contrast, all new generation resources were selected on a least-cost optimized basis without regard for the VCEA development targets in Virginia for Alternative Plans C and E.[36] Alternative Plan A is the least-cost plan that meets applicable carbon regulations and the mandatory RPS Program requirements of the VCEA, but does not meet the development targets for solar, wind, and energy storage resources in Virginia.[37] Dominion presented the results of the modeling for its 2023 IRP using the following table.[38]

	Plan A	Plan B	Plan C	Plan D	Plan E
NPV Total ($B)	$109.70	$127.70	$127.20	$140.90	$138.00
Approximate CO_2 Emissions from Company in 2048 (Metric Tons)	43.8 M	35.9 M	36 M	0 M	0 M
Solar (MW)	10,800 15-yr 19,800 25-yr	10,875 15-yr 19,875 25-yr	10,800 15-yr 19,800 25-yr	10,875 15-yr 23,955 25-yr	11,094 15-yr 24,294 25-yr
Wind (MW)	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr
Storage (MW)	1,050 15-yr 3,960 25-yr	2,370 15-yr 5,190 25-yr	2,220 15-yr 5,220 25-yr	2,370 15-yr 9,780 25-yr	2,910 15-yr 10,350 25-yr
Nuclear (MW)	-- 15-yr -- 25-yr	804 15-yr 1,608 25-yr	804 15-yr 1,608 25-yr	1,608 15-yr 4,824 25-yr	1,072 15-yr 4,288 25-yr
Natural Gas Fired (MW)	5,905 15-yr 9,300 25-yr	2,910 15-yr 2,910 25-yr	2,910 15-yr 2,910 25-yr	970 15-yr 970 25-yr	970 15-yr 970 25-yr
Retirements (MW)	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr 11,399 25-yr	-- 15-yr 11,399 25-yr

Based on these results, Dominion concluded that "Plans B through E all show the significant development of solar and energy storage envisioned by the VCEA, suggesting it remains prudent to proceed with development as set forth in this 2023 RPS Development Plan."[39]

Dominion's 2023 RPS Development Plan includes information on the Company's existing ring-fenced solar facilities,[40] lifetime revenue requirement of Company-owned resources,[41] potential environmental justice impacts of different renewable options,[42] and

---

[34] Ex. 4 (2023 RPS Development Plan) at 10-15, Attachment 6.

[35] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2023-00066 ("2023 IRP" or "2023 IRP Case," as applicable). On February 1, 2024, the Commission provided a notification indicating that the Commission did not reach a majority decision in this matter.

[36] Ex. 4 (2023 RPS Development Plan) at 12.

[37] *Id.* at 10.

[38] *Id.* at 12.

[39] *Id.* Dominion's RPS Development Plan also summarized the results of a high-level reliability assessment conducted by the Company and presented in its 2023 IRP. *Id.* at Attachment 7.

[40] *Id.* at Attachment 3.

[41] *Id.* at Attachment 12.

[42] *Id.* at Attachment 13.

historical (2016-2022) annual capacity factors for the Company's solar fleet.[43] The Company's solar capacity factors are shown below.[44]

Site	State	COD	MWac	Tracking	2016	2017	2018	2019	2020	2021	2022
Morgans Corner	NC	12/28/2015	19.8	Fixed Tilt	19.20%	19.70%	16.40%	17.30%	18.10%	18.40%	15.00%
Scott I	VA	12/11/2016	17*	Single-axis tracking		20.50%	13.80%	14.40%	21.80%	20.70%	21.40%
Whitehouse	VA	12/11/2016	20*	Single-axis tracking		20.40%	16.40%	21.40%	19.70%	22.00%	18.50%
Woodland	VA	12/11/2016	19.16	Single-axis tracking		17.50%	20.10%	19.70%	20.00%	22.30%	17.20%
Remington	VA	10/1/2017	19.8	Fixed Tilt			20.30%	19.90%	19.50%	21.00%	20.90%
Oceana	VA	11/30/2017	17.6*	Single-axis tracking			17.80%	21.40%	19.80%	22.30%	21.60%
Hollyfield	VA	9/6/2018	17	Single-axis tracking				21.60%	22.20%	20.50%	20.10%
Puller	VA	10/31/2018	15	Single-axis tracking				22.20%	22.00%	23.10%	20.80%
Pecan	NC	12/7/2018	74.9	Single-axis tracking				21.80%	24.20%	25.20%	22.90%
Montross	VA	12/12/2018	20*	Single-axis tracking				22.90%	22.40%	22.50%	23.60%
Gloucester	VA	4/22/2019	19.8*	Single-axis tracking					21.70%	23.50%	23.90%
Gutenberg	NC	9/20/2019	79.9	Single-axis tracking					22.10%	25.60%	23.40%
Colonial Trail West	VA	12/26/2019	142.4*	Single-axis tracking					24.20%	21.80%	22.40%
Chestnut	NC	1/31/2020	74.9*	Single-axis tracking						22.80%	21.20%
Grasshopper	VA	10/30/2020	80*	Single-axis tracking						24.40%	23.80%
Spring Grove	VA	11/30/2020	97.9	Single-axis tracking						25.30%	20.90%
Belcher	VA	6/30/2021	88.2	Single-axis tracking							22.60%
Sadler	VA	7/6/2021	100*	Single-axis tracking							21.50%
Bedford	VA	11/23/2021	70*	Single-axis tracking							19.00%
Rochambeau	VA	12/23/2021	19.9*	Single-axis tracking							19.20%
Fort Powhatan	VA	1/19/2022	150	Single-axis tracking							
Solidago	VA	8/1/2023	20*	Single-axis tracking							
Piney Creek	VA	8/15/2023	80*	Single-axis tracking							
Pumpkinseed	VA	9/29/2022	59.6	Single-axis tracking							
Grassfield	VA	10/20/2022	20	Single-axis tracking							
Maplewood	VA	12/19/2022	120	Single-axis tracking							
Sycamore	VA	3/30/2023	42	Single-axis tracking							

[43] *Id.* at Attachment 4 (rev. Nov. 9, 2023).

[44] *Id.* (notes omitted). For clarity of the record, "Sycamore," as shown below, corresponds to the Sycamore solar facility approved as one of the CE-1 Projects, rather than the "Sycamore Cross" project that is the subject of one of Dominion's proposed CE-4 PPAs.

Dominion's 2023 RPS Development Plan provided a consolidated bill analysis under two methodologies[45] – one of which was directed by the *2020 RPS Plan Order*.[46] Dominion summarized the incremental bill increases from its analysis of IRP Plan B with the following tables.[47]

RPS Program Incremental Bill Projections Using Commission-Directed Methodology

Year	Residential[1]	Small General Service[2]	Large General Service[3]
2021	$0.37	$2.01	$1572.00
2022	$4.52	$21.43	$16,796.00
2023	$7.46	$36.73	$20,244.00
2024	$12.59	$55.57	$40,030.00
2025	$17.91	$75.49	$50,604.00
2026	$20.84	$83.18	$50,756.00
2027	$21.13	$77.45	$39,062.00
2028	$21.27	$74.21	$32,130.00
2029	$26.62	$96.85	$47,170.00
2030	$32.67	$121.92	$63,256.00
2031	$39.62	$150.61	$81,506.00
2032	$44.85	$170.51	$92,058.00
2033	$45.49	$166.22	$80,616.00
2034	$47.60	$172.03	$79,958.00
2035	$51.89	$188.62	$88,324.00

RPS Program Incremental Bill Projections Using Company Methodology

Year	Residential[1]	Small General Service[2]	Large General Service[3]
2021	$0.37	$2.01	$1,572.00
2022	$4.52	$21.43	$16,796.00
2023	$7.46	$36.73	$20,244.00
2024	$12.59	$55.55	$40,018.00
2025	$17.64	$78.02	$50,632.00
2026	$19.76	$80.74	$46,588.00
2027	$19.88	$73.46	$35,588.00
2028	$18.81	$68.61	$33,688.00
2029	$22.98	$86.97	$44,924.00
2030	$27.22	$105.32	$57,038.00
2031	$31.78	$124.26	$69,938.00
2032	$34.39	$127.78	$76,726.00
2033	$33.81	$119.72	$67,138.00
2034	$33.82	$123.41	$61,788.00
2035	$35.32	$128.23	$64,954.00

[45] *Id.* at Attachment 11. Dominion also identified five assumptions in the analysis of IRP Plan B that the Company indicated were updated from similar analysis filed with the 2023 IRP. *Id.* at 16.

[46] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing 2020 RPS Proceeding for Virginia Electric and Power Company*, Case No. PUR-2020-00134, 2021 S.C.C. Ann. Rep. 242, Final Order (Apr. 30, 2021) ("*2020 RPS Plan Order*").

[47] Ex. 4 (2023 RPS Development Plan) at 17. Residential impacts represent a customer using 1,000 kilowatt-hours ("kWh")/month. Small general service impacts represent a GS-1 customer using 6,000 kWh/month. Large general service impacts represent a GS-4 customer with a 10 MW demand and using 6,000,000 kWh/month. *Id.*

RPS Compliance Report for 2022

Another part of Dominion's Petition is its RPS Program compliance report for calendar year 2022 ("2022 Compliance Report"). This report indicates that Dominion retired approximately 9.3 million renewable energy certificates ("RECs") to comply with the 2022 RPS requirement.[48] The Company showed its calculation of the compliance requirement, but noted that these calculations do not incorporate the treatment directed by the *RPS Allocation Order*[49] for customers who purchase renewable energy from a competitive service provider.[50] Dominion's 2022 Compliance Report shows the number of RECs retired for 2022 compliance, broken down by resource type, vintage, and location.[51]

Dominion – Direct Testimony

In support of its Petition, the Company offered the direct testimonies of **Todd Flowers**, Director, Business Development for the Company; **Brian M. Keefer**, Manager of Power Contracts and Origination for the Company; **Jarad L. Morton**, Manager, Integrated Strategic Planning with Dominion Energy Services, Inc.; **Amelia H. Boschen**, Manager, Environmental for Dominion Energy Environmental Services; **Ruth B. Prideaux**, Director, Renewable Energy for the Company; **Sean Stevens**, Director of Electric Distribution Grid Solutions for the Company; **Elizabeth B. Lecky**, Manager of Regulation in the Company's Regulatory Accounting Department; and **Christopher C. Hewett**, Regulatory Specialist in the Company's Customer Rates Department.

Mr. Flowers[52] used the following table to summarize the Company-owned solar and storage projects previously approved for recovery through Rider CE.[53]

	Utility-Scale Solar		**Solar + Storage**		**Storage**		**Distributed Solar**	
	No.	MW	No.	MW	No.	MW	No.	MW
CE-1	3	82						
CE-2	11	561	1	150	1	20	2	4
CE-3	7	474			1	16	2	6

[48] Ex. 8 (2022 Compliance Report) at 2. Of this amount, 93,176 RECs were retired to comply with the 1% carveout for resources that are one MW nameplate capacity or less. Ex. 8 (2022 Compliance Report) at 4.

[49] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex. Parte: Allocating RPS costs to certain customers of Virginia Electric and Power Company*, Case No. PUR-2020-00164, 2021 S.C.C. Ann. Rep. 270, 272, Final Order (Sep. 23, 2021) ("*RPS Allocation Order*").

[50] Ex. 8 (2022 Compliance Report) at 1.

[51] *Id.* at 5-6.

[52] In addition to his direct testimony, Mr. Flowers sponsored or co-sponsored Exhibit 1 to the Petition, Filing Schedule 46A, and several parts of the 2023 RPS Development Plan. Ex. 11 (Flowers direct) at 2-3.

[53] *Id.* at 4 (case numbers omitted). As shown above, Mr. Flowers attributes 150 MWs collectively to the Dulles Solar + Storage project. The total figures included in the summary at the beginning of this Report attribute 100 MW to solar and 50 MW to storage for this project, consistent with the *2021 RPS Plan Order*. *Petition of Virginia Electric and Power Company, For approval of the RPS Development Plan, approval and certification of the proposed CE-2 Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under § 56-585.1 A 6 of the Code of Virginia, and a prudence determination to enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia*, Case No. PUR-2021-00146, 2022 S.C.C. Ann. Rep. 309, 316, Final Order (Mar. 15, 2022) ("*2021 RPS Plan Order*").

Mr. Flowers provided updated costs and project schedules for these Company-owned projects. He reported that the costs of the CE-1 Solar Projects, CE-3 Projects, and CE-3 Distributed Solar Projects have remained steady since the 2022 RPS Plan Case, while the total estimated costs for the CE-2 Projects and CE-2 Distributed Solar Projects have increased.[54] As updated by Mr. Flowers, the projected costs and status for these projects, compared to their original estimated costs ("Budget") are summarized below (in millions).

CE-1 Project[55]	**In-Service Date**	**Budget**	**Update**	**Difference**
*Grassfield Solar	*October 2022	$38.3	$37.6	($0.7)
* Norge Solar	*November 2023[56]	$38.7	$43.7	$5.0
*Sycamore Solar	*March 2023	$91.2	$100.0	$8.8
Total – 82 MW Solar		$168.2	$181.3	$13.1

CE-2 Project[57]	**In-Service Date**	**Budget**	**Update**	**Difference**
Camelia Solar	Est. 1Q 2024	$40.3	$45.5	$5.2
Fountain Creek Solar	Est. 3Q 2024	$128.3	$143.0	$14.7
Otter Creek Solar	Est. 1Q 2024	$134.7	$133.9	($0.8)
*Piney Creek Solar	*August 2023	$191.8	$172.1	($19.8)
Quillwort Solar	Est. 1Q 2024	$36.7	$40.2	$3.5
Sebera Solar	Est. 1Q 2024	$37.2	$41.5	$4.5
*Solidago Solar	*August 2023	$36.7	$38.8	$2.2
Sweet Sue Solar	Est. 2025	$162.2	$158.1	($4.1)
Walnut Solar	Est. 2025	$249.7	$267.8	$18.0
Winterberry Solar	Est. 4Q 2023	$38.3	$41.2	$2.9
Winterpock Solar	Est. 2Q 2024	$48.6	$55.0	$6.5
Dry Bridge Storage	Est. 4Q 2023	$41.2	$41.2	$0.0
Dulles Solar + Storage	Est. 2026	$279.7	$443.7	$164.1
*Black Bear Dist. Solar	*September 2023	$7.5	$7.5	$0.0
Springfield Dist. Solar	Est. 2Q 2024	$7.4	$8.4	$1.0
Total – 561 MW Solar		$1,104.5	$1,137.2	$32.8
Total – 20 MW Storage		$41.2	$41.2	$0.0
Total – 150 MW Solar + Storage		$279.7	$443.7	$164.1
Total – 4 MW Dist. Solar		$14.9	$15.9	$1.0

[54] Ex. 11 (Flowers direct) at 4-5. *See 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, Final Order (Apr. 14, 2023) ("*2022 RPS Plan Order*" or "2022 RPS Plan Case," as applicable).

[55] Ex. 11 (Flowers direct) at 4, attached Sched. 1. All MW figures in this summary of Mr. Flowers' direct testimony are nameplate, alternating current ("AC") capacity.

[56] Tr. at 113 (Flowers).

[57] Ex. 11 (Flowers direct) at 4, attached Sched. 2. As shown above, the sum of the "Budget" figures for individual utility-scale CE-2 solar projects found in Mr. Flowers' Schedule 2 is $1.1045 billion, which equals the amount identified *2021 RPS Plan Order*. *2021 RPS Plan Order*, 2022 S.C.C. Ann. Rep. at 317. As shown above, the estimated total costs for these projects are $32.8 million above the original budget. These updated estimated costs are $9.7 million higher than the updated estimate of $1.1275 billion presented in the 2022 RPS Plan Case. Ex. 11 (Flowers direct) at attached Sched. 2, p. 1.

CE-3 Project[58]	In-Service Date	Budget	Update	Difference
Bridleton Solar	Est. 3Q 2024	$46.4	$46.9	$0.5
Cerulean Solar	Est. 2Q 2026	$183.2	$185.8	$2.6
Courthouse Solar	Est. 3Q 2026	$409.9	$403.3	($6.6)
Kings Creek Solar	Est. 1Q 2025	$48.8	$48.8	$0.0
Moon Corner Solar	Est. 2Q 2026	$185.0	$185.0	$0.0
North Ridge Solar	Est. 4Q 2024	$52.5	$52.0	($0.5)
Southern Virginia Solar	Est. 4Q 2025	$261.5	$260.4	($1.1)
Shands Storage	Est. 2Q 2025	$57.6	$57.6	$0.0
Ivy Landfill Dist. Solar	Est. 2Q 2025	$14.8	$18.8	$4.0
Racefield Dist. Solar	Est. 3Q 2025	$13.8	$14.9	$1.1
Total – 474 MW Solar		$1,187.3	$1,182.2	($5.1)
Total – 16 MW Storage		$57.6	$57.6	$0.0
Total – 6 MW Dist. Solar		$28.7	$33.7	$5.1

As reported by Mr. Flowers, six of these projects have been placed in service. The in-service projects, shown above with asterisks, represent approximately 183.6 MW of nameplate capacity.[59]

Focusing on the CE-2 Projects, Mr. Flowers attributed the $19.8 million decreased cost estimate for Piney Creek Solar to a $34.9 million decrease in the interconnection cost estimate (which was partially offset by other increases).[60] He attributed the $164.1 million increased cost estimate for the Dulles Solar + Storage facility to construction delays and cost increases. He indicated that the Metropolitan Washington Airports Authority required a more restrictive civil construction sequence, which resulted in a revised engineering plan and an extended construction timeline. The estimated engineering, procurement, and construction ("EPC") contractor costs increased **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSNTIVE INFORMATION]**.[61] He indicated that the Company had to rebid the energy storage portion of the project because the original contract that was selected could not meet safety standards required by the Company.[62]

Mr. Flowers believes that the location of the Dulles Solar + Storage facility on federal land and the effects of the pandemic on supply chain and procurement make its circumstances unique. While he acknowledged the challenges presented by this project, he indicated that it will also provide unique benefits as a solar plus storage facility in highest load area of the Company's service territory.[63]

Notwithstanding the increased costs for the CE-2 Projects, Mr. Flowers asserted that expenditures for the CE-1, CE-2, and CE-3 Projects are reasonable and prudent. He indicated

[58] Ex. 11 (Flowers direct) at 4, attached Sched. 3.
[59] *Id.* at 4 and Attached Sched. 1, p. 1; Tr. at 113 (Flowers).
[60] Ex. 11 (Flowers direct) at Attached Sched. 2, pp. 4-5.
[61] Exs. 11, 11-ES (Flowers direct) at Attached Sched. 2, p. 10.
[62] Tr. at 111 (Flowers).
[63] Tr. at 110-13 (Flowers).

that much of these increases is driven by factors beyond Dominion's control, such as increased cost of materials, federal regulations, and local agency impacts. He emphasized the operational benefits of these facilities and that they are needed to meet customers' capacity, energy, and REC needs.[64]

Among other information, Mr. Flowers provided the following summary information for the proposed CE-4 Projects and Distributed Solar Project:[65]

CE-4 Project	Size (MWac)	Estimated Cost ($Mill.)	Locality (All Counties)	Interconnection	Commercial Operation Date
Beldale	57	$157.7	Powhatan	Transmission	2026
Blue Ridge	95	$299.4	Pittsylvania	Transmission	2026
Bookers Mill	127	$249.0	Richmond	Transmission	2024
Michaux	50	$133.1	Henry/Pittsylvania	Transmission	2026
Peppertown	5	$16.5	Hanover	Distribution	2024
Alberta	3	$10.9	Brunswick	Distribution	2024

Dominion's Petition requests a CPCN for all of these projects except for Peppertown and Alberta.[66] Dominion would construct Beldale, Blue Ridge, and Michaux, while Dominion would acquire Peppertown and Alberta upon mechanical completion.[67] Mr. Flowers explained that Dominion began constructing Bookers Mill in 2021, after receiving a permit by rule from DEQ. Initially, Bookers Mill was developed for a specific customer (rather than Dominion's jurisdictional customers) before that customer decided it no longer wanted to pursue the project.[68]

Mr. Flowers provided summaries and maps for all six projects.[69] He provided a general project milestone schedule for these projects.[70] He does not expect cost variances similar to those experienced with the previously approved solar and storage projects. He testified that the CE-2 project agreements were "pretty much [at] the height of the pandemic."[71]

Mr. Flowers addressed economic development[72] and the potential environmental justice impacts of each proposed project.[73]

---

[64] Ex. 11 (Flowers direct) at 5-6.
[65] *Id.* at 6 and attached Scheds. 4-9 (with the estimated cost figures from Scheds. 5 and 6 as revised on Nov. 9, 2023).
[66] *Id.* at 7. For Peppertown and Alberta, the Company submitted letters to Staff stating its intention to construct these projects, consistent with 20 VAC 5-302-10 and the Commission's prior determination that projects of 5 MW or less do not require a CPCN. *Id.* at 7 and attached Sched. 10.
[67] *See, e.g., id* at 13-14.
[68] *Id.* at 13, 18.
[69] *Id.* at attached Scheds. 4-9.
[70] *Id.* at attached Sched. 12.
[71] Tr. at 94 (Flowers).
[72] Ex. 11 (Flowers direct) at 14-15.
[73] *Id.* at 15 and attached Scheds. 4-9.

Mr. Flowers provided estimated costs for the utility-scale CE-4 Projects, totaling approximately $855.7 million, excluding financing costs, or approximately $2,562/kilowatt ("kW") at the total 334 MW (nominal AC) rating.[74] For the projects Dominion is constructing, he indicated that the cost estimates are consistent with the executed EPC contracts or the most recent EPC data provided in negotiations. For Peppertown, he indicated these estimated costs are consistent with the fixed-price contract negotiated and incorporated into the mechanical completion transaction.[75]

Mr. Flowers described the Company's process for determining whether a solar project would be optimally constructed using fixed tilt or tracking technology. He does not believe the Company conducted such a comparison for the proposed Peppertown or Alberta facilities.[76]

According to Mr. Flowers, the CE-4 Projects are needed to comply with the VCEA, and also to serve customers' capacity, energy, and REC needs. He indicated that the CE-4 Projects will provide environmental benefits by displacing output from fossil fuel-fired facilities, thereby reducing the system's carbon emissions. In addition to environmental benefits, the CE-4 Projects are eligible for federal tax credits that will reduce overall customer costs.[77]

Mr. Flowers indicated that the $10.9 million estimated cost of the CE-4 Distributed Solar Project, or approximately $3,642/kW at the 3 MW (nominal AC) rating, will be managed through contracted negotiated milestones that culminate with mechanical completion, when the project is acquired. He asserted that this project is needed to comply with the VCEA, and also to serve customers' capacity, energy, and REC needs. He indicated this project also provides diversification of project resource scale and size, as compared to utility-scale projects. He added that projects of this smaller scale have opportunities in land development and interconnection that are not otherwise suitable for utility-scale development. He further asserted that lower individual project development and capital costs increase opportunities for using a more diverse set of project developers.[78]

Mr. Flowers explained how Dominion selected these projects. He sponsored Dominion's report on the Development RFP,[79] which provides details of the RFP process, requirements, price and non-price evaluation criteria, and the results.[80] Four solar projects were selected out of the 12 development proposals received (9 solar and 3 energy storage) in response to this RFP. Dominion also selected two solar projects that were Company-sourced.[81]

---

[74] *Id.* at 18 (rev. Nov. 9, 2023) and attached Scheds. 4-9.
[75] *Id.* at 19. The EPC contract for Michaux was executed approximately one week before the Petition was filed. Dominion indicated that while the final negotiated EPC cost came in slightly greater than the Petition's estimate, there is no overall impact to the Company's overall cost estimate for Michaux because the additional cost is absorbed in the project's contingency cost category. Tr. at 357 (Flowers).
[76] Tr. at 120-21 (Flowers).
[77] Ex. 11 (Flowers direct) at 8.
[78] *Id.* at 21.
[79] Exs. 9, 10-ES at Filing Sched. 46A, Statement 3.
[80] The results include summaries of the bids received and bid scores or rankings according to price and non-price criteria. *See, e.g.*, Ex. 10-ES at Filing Sched. 46A, Statement 3, p. 194.
[81] Ex. 11 (Flowers direct) at 10-11. The two Company-sourced projects are Blue Ridge and Bookers Mill. Ex. 9 at Filing Sched. 46A, Statement 3, p. 6.

Mr. Flowers indicated that the subject projects will help the Company meet various requirements and targets from the VCEA, including directives for Dominion to petition for: (i) 16,100 MW of solar or onshore wind resources, including 1,100 MW from solar projects with nameplate capacity of 3 MW or less by 2035; and (ii) 3,000 MW of solar or onshore wind resources by 2024.[82]

Mr. Flowers used publicly available data from EIA to calculate a Virginia average DC/AC ratio of 1.31.[83] For projects below this average, Mr. Flowers provided an explanation.[84]

Mr. Flowers asserted that the CE-4 Projects will benefit customers. Citing Mr. Morton's direct testimony, Mr. Flowers asserted that these utility-scale projects and Alberta are estimated to provide $150 million of positive net present value, collectively, based on an assessment using capacity factor and REC assumptions Dominion believes are most likely.[85]

Mr. Flowers concluded that the projects presented by the Petition are prudent, cost-effective resources that will:

- Further the directives of the VCEA to develop significant amounts of new renewable generation and energy storage capacity in the Commonwealth, including the sub-targets for new distributed solar resources;
- Support compliance with the mandatory RPS Program requirements;
- Address the Company's need for energy and capacity to meet its forecasted load growth;
- Provide emissions-free energy from renewable energy resources;
- Contribute to fuel diversity so that the Company's generation portfolio is not overly dependent on any one fuel source;
- Enhance the cost-effectiveness and customer value of projects by pursuing available federal tax credits; and
- Support economic development in the Commonwealth.[86]

Together with the PPAs presented by Company witness Keefer, the resources presented by the Petition total approximately 772 MW of new solar capacity. Approximately 56% of this amount is from facilities owned by third parties.[87]

Mr. Keefer supported the Company's request that the Commission determine the CE-4 PPAs and CE-4 Distributed Solar PPAs, totaling 435 MW of solar, are reasonable and prudent. He also provided a status update on PPAs previously approved under the VCEA.[88]

[82] Ex. 11 (Flowers direct) at 16-17, 19-20.
[83] *Id.* at 17.
[84] *Id.* at attached Scheds. 4,6, 7, and 8, at Feasibility and Engineering Design.
[85] *Id.* at 19. As discussed in Section II of this Report's Analysis, the $150 million portfolio estimate assumes, among other things, that the avoided cost of RECs equals the statutory deficiency penalty. Additionally, the $150 million portfolio estimate is the result of adding positive estimated global value to negative estimated value for Dominion's ratepayers.
[86] *Id.* at 22.
[87] *Id.* at 23.
[88] In addition to his direct testimony, Mr. Keefer sponsored Filing Schedule 46 B and several parts of the RPS Development Plan. Ex. 18 (Keefer direct) at 2-3.

Mr. Keefer summarized the Commission's PPA approvals since the enactment of the VCEA with the following table.[89]

	Utility-Scale Solar		Solar + Storage		Storage		Distributed Solar	
	No.	MW	No.	MW	No.	MW	No.	MW
CE-1	6	416						
CE-2	5	137	2	39	1	20	12	33
CE-3	5	254			2	49	6	16

Mr. Keefer reported that three PPA sites achieved commercial operations in the first half of 2023.[90] However, developers have terminated six CE-2 Distributed Solar PPAs because the developers were unable to fulfill the terms of the PPA, citing the inability to obtain conditional use permits and inflationary cost effects.[91]

Turning to the proposed PPAs, Mr. Keefer provided the following summary information, listed in random order, with the price and developer designated as extraordinarily sensitive.[92]

[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION (in bold)]

CE-4 PPAs (All Solar)

Project	Size (MWac)	Locality	Developer	Year 1 Price ($/MWh)	COD
Windsor	85.0	Isle of Wight	[redacted]	[redacted]	2026
Sycamore Cross	240.0	Isle of Wight	[redacted]	[redacted]	2026
Richmond Hwy	5.0	City of Pamplin	[redacted]	[redacted]	2027
Jessie DuPont Memorial	4.3	Wicomico Church	[redacted]	[redacted]	2026
Winfield Solar	19.9	Sussex	[redacted]	[redacted]	2026
Optimist Solar	36.2	Sussex	[redacted]	[redacted]	2026
Flowers Solar	19.9	Dinwiddie	[redacted]	[redacted]	2026
Highlands CF Ft 23	10.0	Wise	[redacted]	[redacted]	2026

[END EXTRAORDINARILY SENSITIVE INFORMATION (in bold)]

[89] *Id.* at 3 (case numbers omitted); Ex. 11 (Flowers direct) at 4. As shown above, Mr. Keefer attributes 39 MWs collectively to solar + storage PPAs. The total figures included on page one of this Report attribute 26 MW to solar and 13 MW to storage for these PPAs, consistent with the *2021 RPS Plan Order*. *2021 RPS Plan Order*, 2022 S.C.C. Ann. Rep. at 322.

[90] Ex. 18 (Keefer direct) at 3. These PPAs are Stratford, Watlington, and Pleasant Hill. *Id.* at attached Sched. 3, p. 1.

[91] *Id.* at 3-4.

[92] Exs. 18, 18-ES (Keefer direct) at 4-5. "COD" is the projected commercial operation date. As identified by Staff witness Ricketts, the Sycamore Cross and Windsor CE-4 PPAs allow for a range of capacities. In a pending CPCN proceeding the design capacity for Sycamore Cross is identified as 203 MW. Ex. 41 (Ricketts) at 6-7 and Appendix AR-1, p. 17.

[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION (in bold)]

CE-4 Distributed Solar PPAs

Project	Size (MWac)	Locality	Developer	Year 1 Price ($/MWh)	COD
Nathalie C	3.0	Halifax	[redacted]	[redacted]	2026
Waynesboro B	3.0	Augusta	[redacted]	[redacted]	2026
Pivot Energy VA 7	3.0	City of Hurt	[redacted]	[redacted]	2026
USS Mt. Sidney Solar	3.0	Augusta	[redacted]	[redacted]	2026
USS Greenlaw Solar	3.0	Stafford	[redacted]	[redacted]	2026

[END EXTRAORDINARILY SENSITIVE INFORMATION (in bold)]

Mr. Keefer testified that three CE-4 PPAs would be interconnected to the transmission grid. Five CE-4 PPAs and all CE-4 Distributed Solar PPAs would be interconnected to the distribution grid. All but two of these PPAs would use single-axis tracking technology.[93]

Mr. Keefer indicated that these proposed PPAs are needed to comply with the VCEA, and also to serve customers' capacity, energy, and REC needs. He also testified that these PPAs will help Dominion meet the development targets of the VCEA.[94] Dominion intends for any RECs generated by the proposed PPAs to be banked or used for RPS compliance.[95]

Mr. Keefer sponsored the report on the 2022 PPA RFP from which the proposed PPAs were selected.[96] Of the 41 utility-scale PPA proposals received, the Company identified 13 as non-conforming.[97] Dominion selected 15 utility-scale solar PPAs and one storage PPA. However, after four developers informed Dominion that seven PPA proposals were no longer economically viable at their bid prices, and PPA negotiations were not completed in time for inclusion of the storage PPA in the instant Petition, this left the eight CE-4 PPAs.[98]

Mr. Keefer indicated that Dominion allowed all conforming storage PPA bidders to revise their bid prices after receiving a request from one bidder to allow a refreshed bid to submit a lower price due to reduced forward market prices for lithium. He indicated that while two bidders elected to keep their original offer price, three provided reduced pricing consistent with the level of decrease in lithium prices. It does not appear to him that this practice is one Dominion should regularly employ absent a material substantive shift in market dynamics that lowers facility costs.[99]

Of the 19 distributed solar PPA proposals received from the 2022 PPA RFP, the Company selected 13. However, after four developers withdrew eight proposals, this left the five CE-4 Distributed Solar PPAs.[100]

---

[93] Ex. 18 (Keefer direct) at corrected 5 (rev. Nov. 9, 2023). The Jesse Dupont Memorial Solar PPA and Nathalie C Distributed Solar PPA use fixed tilt technology. *Id.*

[94] *Id.* at 5-6.

[95] *Id.* at 9.

[96] Exs. 9, 10-ES at Filing Sched. 46B, Statement 1.

[97] *Id.* at Filing Sched. 46B, Statement 1, p. 94.

[98] Ex. 18 (Keefer direct) at 7.

[99] *Id.* at 8.

[100] *Id.* at 7.

The structure of the proposed PPAs is similar to the PPAs approved by the Commission in prior RPS plan proceedings. Through these PPAs, the Company has agreed to purchase all the output from the facilities, including RECs.[101]

Mr. Keefer addressed economic development[102] and the potential environmental justice impacts of the proposed PPAs.[103] Of the 13 total sites, all are located within a census block group considered an environmental justice community under the Virginia Environmental Justice Act ("VEJ Act"), and three are located within a U.S. census tract that meets the definition of a historically economically disadvantaged community under the VCEA.[104] Mr. Keefer provided a map to illustrate that the proposed PPAs are spread across the Commonwealth and do not cluster in any specific community or communities.[105]

Mr. Keefer identified the Petition's request to move cost recovery for RPS plan PPAs from Rider PPA to Rider CE. He listed the PPA projects that are included in the Petition's proposed Rider CE revenue requirement.[106]

Mr. Keefer acknowledged that the structure of CE-1, CE-2, CE-3, and C-4 PPAs does not provide for cost variances akin to those experienced at Company owned projects.[107]

Mr. Keefer sponsored a document showing the prices and the weighted average prices of the CE-3 Solar PPAs and CE-3 Distributed Solar PPAs and the prices and weighted average prices of the solar CE-4 PPAs and CE-4 Distributed Solar PPAs.[108] **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][109] [redacted][110] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

Mr. Morton supported the Company's forecasted need for the CE-4 Projects, the CE-4 Distributed Solar Project, the CE-4 PPAs, and the CE-4 Distributed Solar PPAs.[111] In 2027, the Company-owned solar projects and the solar PPAs are expected to provide approximately 635,730 megawatt-hours ("MWh") and 925,710 MWh of energy production, respectively.

---

[101] *Id.* at 8.
[102] *Id.* at 9.
[103] *Id.* at 10-11.
[104] *Id.* The VEJ Act was codified as Code §§ 2.2-234 and 2.2-235.
[105] Ex. 18 (Keefer direct) at 11 and attached Sched. 2.
[106] *Id.* at 11-12 and attached Sched. 3.
[107] Tr. at 132-34 (Keefer).
[108] Ex. 19-ES.
[109] *Id.*
[110] Tr. Day 1 ES Session 2 at 10-11 (Keefer). The "Inflation Reduction Act" refers to the federal Inflation Reduction Act of 2022, Public Law 117-169 (2022).
[111] In addition to his direct testimony, Mr. Morton sponsored Filing Schedule 46C and portions of the RPS Development Plan. Ex. 20 (Morton direct) at 2-3.

Together, these resources would contribute approximately 1,561,440 RECs, or 8.3% of the forecasted REC need, in 2027.[112]

Mr. Morton provided charts to illustrate the effect that the proposed CE-4 resources would have on Dominion's projected capacity position and projected energy position.[113] In his view, these charts demonstrate that there is a capacity and energy need in both the near and long term.[114] Some of his charts illustrating the Company's projected capacity, energy, and REC needs are included below in Section II of this Report's Analysis. He testified that these three needs are evaluated individually and that he believes the proposed projects are needed for all three.[115]

Mr. Morton provided Dominion's net present value economic analysis of the CE-4 Projects and Distributed Solar Project compared to market purchases.[116] PLEXOS modeling software was used to calculate net present values over the 35-year operating lives for solar resources under a cost-of-service methodology. He indicated that Dominion generally used the same assumptions for the modeling completed in support of the Petition as the Company used in the 2023 IRP.[117] Dominion used the 2023 PJM load forecast, scaled down to the Dominion load serving entity level and then adjusted to account for energy efficiency programs and retail choice.[118] A base case commodity price forecast prepared by ICF International, Inc. ("ICF"), vintage July 2023, was used.[119]

In its net present value analysis, Dominion assumed a solar capacity factor based on the lower of the design capacity factor or a three-year (2020, 2021, and 2022) average of the Company's existing solar facilities in Virginia. Dominion also modeled the projects using their design capacity factors to the extent they are higher than the three-year average.[120] For capacity value through 2034, Dominion used the most recent effective load carrying capability methodology annual values published by PJM in December 2022. Beyond 2034, Dominion used effective load carrying capacity values projected by ICF and the Company filled in the gap between PJM and ICF values.[121]

---

[112] *Id.* at 5. One REC is generated from each MWh of applicable energy production. *Id.* at 4.
[113] *Id.* at 7-8.
[114] *Id.* at 9.
[115] Tr. at 147 (Morton).
[116] Ex. 20, 20-ES (Morton direct) at attached Scheds. 1-6. He provided this analysis notwithstanding his opinion that the VCEA "shifted the question of options away from a choice between a number of different types of generating resources, to the options being between the Company-owned projects available and, separately, between the PPAs available." *Id.* at 10 (internal quotations omitted).
[117] *Id.* at 11. Dominion incorporated in the Petition's net present value analysis a higher return on equity, and lower discount rate and weighted average cost of capital, "to reflect more recent financial estimates and legislative requirements." *Id.*
[118] *Id.*
[119] *Id.* at 12.
[120] *Id.* *See also* Ex. 49 (Morton rebuttal) at 7-8 (explaining the conceptual and practical problems associated with using a three-year historical average capacity factor in the economic analysis of projects with design capacity factors that are lower than the historical average).
[121] Ex. 20 (Morton direct) at 12-13.

For federal tax credits, Mr. Morton confirmed that Dominion will pursue available tax credits, which the Company expects will reduce overall cost to customers. Dominion's Petition assumed the CE-4 Projects and CE-4 Distributed Solar Project would receive production tax credits available under the Inflation Reduction Act of 2022. Mr. Morton added that the Petition assumed that Michaux would also receive an additional 10% production tax credit bonus.[122]

Mr. Morton indicated that Dominion also quantified and included REC benefits and a social cost of carbon in its net present value analysis for the solar projects. REC benefits are incorporated as an avoided cost under three scenarios that value such benefits using: (i) the statutory deficiency payment; (ii) a forecasted market price for RECs; or (iii) a blend of 30% forecasted REC market prices and 70% statutory deficiency payment penalties.[123] Dominion believes the first or third scenario is more likely based on the Company's concerns about REC supply if the Company does not develop projects or incentivize their development through PPAs.[124]

To calculate a social cost of carbon benefit, Dominion multiplied each project's annual solar generation by the marginal carbon dioxide ("CO_2") emissions intensity from the 2023 PJM Emission Report "to determine how much carbon the project would displace." Dominion then multiplied that amount by the federal government's forecasted social cost of carbon ($51 per metric ton in 2020). Consistent with the *2022 RPS Plan Order*, Dominion excluded from its carbon dispatch adder an indirect cost associated with the social cost of carbon in the modeling of the CE-4 resources.[125] Mr. Morton indicated that valuing carbon in Dominion's economic analysis reflects a different purpose than the methodology discussed by Company witness Boschen.[126]

---

[122] *Id.* at 13.
[123] *Id.* at 14 and attached Scheds. 1-6.
[124] *Id.* at 14.
[125] *Id.* at 15-16. In discovery attached to Staff testimony, Dominion indicated that the $51 per metric ton price is based on Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. Ex. 41 (Ricketts) at 10, n.33, and Appendix AR-1, p. 15.
[126] *Id.* at 16. Mr. Morton confirmed that the $51/ton amount used in his analysis is an estimate of the global harm caused by carbon dioxide emissions. *See, e.g.*, Ex. 50 at 14-16; Tr. at 386 (Morton).

For the CE-4 Projects and Distributed Solar Project, Mr. Morton summarized the Petition's net present value analysis results using the following three tables that only differ due to the assumed avoided REC value.[127] More specifically (as noted), the first table assumes an avoided Virginia REC cost (*i.e.*, a benefit) priced at the statutory penalty rate for RPS non-compliance, the second table assumes the same benefit is priced using the ICF forecast primarily, and the third table uses the 70%/30% blended value.

Project Name	Project Type	Solar MW	NPV without SCoC $000	NPV of SCoC $000	NPV $000
Beldale	Utility Scale Solar	57	(14,066)	39,865	25,798
Blue Ridge[1]	Utility Scale Solar	95	(63,228)	73,067	9,838
Bookers Mill	Utility Scale Solar	127	28,628	87,211	115,838
Michaux	Utility Scale Solar	50	(27,190)	33,742	6,552
Peppertown	Utility Scale Solar	5	(8,462)	3,304.6	(5,157)
Alberta[2]	Distributed Solar	3	(5,858)	2,294.5	(3,563)
Total NPV					**149,306**

Notes: NPVs include REC benefit valued at applicable deficiency payment.
NPVs include production tax credits (PTC) per the Inflation Reduction Act.
Assumes 2023 PJM Load Forecast and base fuel commodity prices.
Design capacity factor is modeled for all projects in the table above.
(1) Blue Ridge NPV assuming 3-year average capacity factor is ($84,496) without the social cost of carbon; the NPV of the social cost of carbon is $68,049, for a total project NPV of ($16,447), using these assumptions.
(2) Alberta NPV assuming 3-year average capacity factor is ($6,136) without the social cost of carbon; the NPV of the social cost of carbon is $2,212, for a total project NPV of ($3,923), using these assumptions.

Project Name	Project Type	Solar MW	NPV without SCoC $000	NPV of SCoC $000	NPV $000
Beldale	Utility Scale Solar	57	(65,987)	39,865	(26,123)
Blue Ridge[1]	Utility Scale Solar	95	(158,393)	73,067	(85,327)
Bookers Mill	Utility Scale Solar	127	(77,308)	87,211	9,903
Michaux	Utility Scale Solar	50	(71,137)	33,742	(37,395)
Peppertown	Utility Scale Solar	5	(12,476)	3,305	(9,171)
Alberta[2]	Distributed Solar	3	(8,645)	2,295	(6,350)
Total NPV					**(154,464)**

Notes: NPVs include REC benefit valued at forecasted market price.
NPVs include production tax credits (PTC) per the Inflation Reduction Act.
Assumes 2023 PJM Load Forecast and base fuel commodity prices.
Design capacity factor is modeled for all projects in the table above.
(1) Blue Ridge NPV assuming 3-year average capacity factor is ($173,126) without the social cost of carbon; the NPV of the social cost of carbon is $68,049, for a total project NPV of ($105,077), using these assumptions.
(2) Alberta NPV assuming 3-year average capacity factor is ($8,823) without the social cost of carbon; the NPV of the social cost of carbon is $2,212, for a total project NPV of ($6,611), using these assumptions.

Project Name	Project Type	Solar MW	NPV without SCoC $000	NPV of SCoC $000	NPV $000
Beldale	Utility Scale Solar	57	(29,643)	39,865	10,222
Blue Ridge[1]	Utility Scale Solar	95	(91,778)	73,067	(18,711)
Bookers Mill	Utility Scale Solar	127	(3,470)	87,211	83,741
Michaux	Utility Scale Solar	50	(40,374)	33,742	(6,632)
Peppertown	Utility Scale Solar	5	(9,678)	3,305	(6,373)
Alberta[2]	Distributed Solar	3	(6,702)	2,295	(4,408)
Total NPV					**57,838**

Notes: REC benefits valued at 70% applicable deficiency payment and 30% forecasted market price.
NPVs include production tax credits (PTC) per the Inflation Reduction Act.
Assumes 2023 PJM Load Forecast and base fuel commodity prices.
Design capacity factor is modeled for all projects in the table above.
(1) Blue Ridge NPV assuming 3-year average capacity factor is ($111,085) without the social cost of carbon; the NPV of the social cost of carbon is $68,049, for a total project NPV of ($43,036), using these assumptions.
(2) Alberta NPV assuming 3-year average capacity factor is ($6,950) without the social cost of carbon; the NPV of the social cost of carbon is $2,212, for a total project NPV of ($4,738), using these assumptions.

[127] Ex. 20 (Morton direct) at attached Scheds. 1-3.

Mr. Morton summarized the results of Dominion's economic analysis of the proposed PPAs using the following three tables that also differ based on avoided REC value (as noted).[128]

[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]

[redacted]

[END EXTRAORDINARILY SENSITIVE INFORMATION]

[128] *Id.* at attached Scheds. 4-6.

Mr. Morton indicated that a negative net present value "is what it is." However, he views this information as only a data point used by the Company, along with other factors, to determine the viability of various projects.[129]

Ms. Boschen discussed the environmental impact analysis performed by Dominion for the CE-4 Projects. She also sponsored the DEQ Supplements for Beldale, Blue Ridge, and Michaux, which are attached to her direct testimony.[130] Dominion did not file a DEQ Supplement for Bookers Mill because Dominion previously received a DEQ permit by rule and Clean Water Act Section 404 and 401 permits from the U.S. Army Corps of Engineers and the DEQ, respectively.[131]

For air impacts, Ms. Boschen expects localized impacts during construction of the CE-4 Projects. She does not expect any impact to ambient air quality from operation of the new facilities. Ms. Boschen expects that the CE-4 Projects would not generate any wastewater and water requirements would generally be very minimal.[132]

Ms. Boschen explained how stormwater discharges during construction and runoff during operation are regulated.[133] While the CE-4 Projects will be designed to avoid and minimize impacts to wetlands and streams, the Company will work with all applicable regulatory agencies to obtain permits and provide appropriate mitigation if there are unavoidable impacts to streams or wetlands.[134]

Similarly, while the CE-4 Projects will be designed to avoid and minimize impacts to archaeological, historic, scenic, cultural, and architectural resources to the greatest extent practicable, Dominion will work with the Department of Historic Resources ("DHR"), and other stakeholders as needed, if mitigation for unavoidable impacts is required.[135]

According to Ms. Boschen, adverse impacts to natural heritage resources are not expected.[136] The Company made efforts to avoid and minimize the need for tree removal and habitat fragmentation where possible. These efforts included siting to identify previously disturbed and cleared areas near the proposed interconnection location, and designing projects in a manner that focuses on development within unconstrained lands while conserving, through avoidance, sensitive areas to the greatest extent practicable. She added, among other things, that undisturbed and buffered riparian corridors will allow for animal and plant genetic exchange

[129] Tr. at 149-50 (Morton). *See also* Tr. at 399 (Morton) ("a negative [net present value] might be a con, but you also need to look at the pros in that consideration").

[130] DEQ Supplements were not provided for Peppertown and Alberta because, as discussed by Mr. Flowers, the Company did not request CPCNs for these projects. However, Ms. Boschen represented that the Company will comply with all relevant environmental laws and regulations in the construction of these projects, and will obtain all necessary permits from the appropriate agencies. Ex. 24 (Boschen direct) at 3.

[131] Ex. 24 (Boschen direct) at 3 (referencing the anti-duplication provisions of Code § 56-580).

[132] Ex. 24 (Boschen direct) at 4-5.

[133] *Id.* at 5.

[134] *Id.* at 5-6.

[135] *Id.* at 6.

[136] *Id.*

across the landscape, support species richness, and maintain connectivity with adjacent forested areas.[137]

Ms. Boschen discussed CO_2 emission displacement figures that the Company provided in the three DEQ Supplements. She indicated that Dominion voluntarily developed a tool to quantify the displacement in such emissions from fossil fuel generation, compared to forest carbon storage lost due to solar construction. This information is offered as a high-level representation of the displacement of CO_2 emissions acknowledging the potential concern related to loss of CO_2 sequestration. She indicated that the results of this tool, which the Company developed using a peer reviewed and publicly available methodology from the U.S. Environmental Protection Agency and Forest Service, show a significant net benefit in the reduction of carbon emissions.[138]

Ms. Boschen committed that Dominion will apply for and receive all applicable permits and approvals prior to construction. Additionally, the Company will use avoidance and best management practices to meet all applicable environmental regulations and permit conditions.[139]

Environmental impacts specific to Beldale, Blue Ridge, and Michaux, including those identified by Ms. Boschen and her DEQ Supplements, are discussed in Section II of this Report's Analysis below.

Ms. Prideaux sponsored part of the 2023 RPS Development Plan and Filing Schedule 46D, which provides the Company's updated projected and actual operations and maintenance ("O&M") and capital maintenance costs and provides certain cost support information for the utility-scale CE-1, CE-2, and CE-3 Projects.[140] Ms. Prideaux provided an update on Dominion's transition to an in-house solar operations management team for remote O&M activities. Dominion plans to implement this transition in the fourth quarter of 2023 for the CE-1 Solar Projects and on the respective commercial operation dates for the CE-2, CE-3, and CE-4 Projects.[141]

Ms. Prideaux also provided, among other things, the Company's current five-year O&M and capital budget plans for each of the CE-1, CE-2, and CE-3 Projects.[142]

Ms. Prideaux confirmed that historic capacity factor values changed from last year's case to this year's. She indicated that Dominion made such changes after discovering errors in the capacity factor calculations reported last year.[143] She further indicated that Dominion uses the nominal capacity, degraded by 0.25% in the first year of operations and 0.5% for every year thereafter, to calculate capacity factors.[144]

---

[137] *Id.* at 7.
[138] *Id.* at 8.
[139] *Id.* at 8-9.
[140] Ex. 25 (Prideaux direct) at 2.
[141] *Id.* at 3.
[142] Exs. 25, 25-ES (Prideaux direct) at attached Scheds. 1, 2, and 3.
[143] Tr. at 165 (Prideaux).
[144] Tr. at 166-67 (Prideaux).

Mr. Stevens sponsored Filing Schedule 46E, which provides the Company's updated projected and actual O&M and capital maintenance costs and provides certain cost support information for the CE-2 and CE-3 Distributed Solar Projects.[145] Mr. Stevens also provided, among other things, the Company's current five-year O&M and capital budget plans for each of these projects.[146]

Ms. Lecky calculated the Petition's proposed Rider CE revenue requirement of $136.7 million. This amount is based on: (1) annualized total Projected Cost Recovery Factor revenue requirements of $194.2 million and $132.7 million for pre-commercial operation and post-commercial operation periods,[147] respectively; and (2) an Actual Cost True-Up Factor revenue requirement of ($14.3 million).[148]

Ms. Lecky's proposed revenue requirement reflects the Petition's proposal to consolidate Rider PPA and Rider CE.[149] As proposed, consolidation would result in costs and benefits associated with all Rider CE Projects and PPAs being recovered through one rate adjustment clause. According to Ms. Lecky, consolidation would serve the interests of judicial economy and customer transparency because of the similarity of the underlying resources and since the Commission already considers the prudence of PPAs in the annual RPS plan cases. Ms. Lecky noted that because the rate year for the existing Rider PPA was approved through August 31, 2024, in Case No. PUR-2022-00202, the Petition requests that Rider PPA end effective April 30, 2024, the date immediately before the proposed Rider CE rate year. She indicated that any revenue requirement impacts resulting from the change in Rider PPA's rate year can be accounted for in a future Rider CE true-up.[150]

Ms. Lecky represented that Dominion's proposed revenue requirement is consistent with the calculations presented in the prior RPS plan case, with three exceptions. First is the proposed consolidation of Rider PPA with Rider CE discussed above. Second, the Petition uses an updated revenue lag based on 2022 data in certain cash working capital calculations in this filing, which she understood would be litigated in Case No. PUR-2023-00094. Third, her revenue requirement incorporates the following changes to expected commercial operation dates.[151]

[145] Ex. 26 (Stevens direct) at 2. Actual costs are provided through December 31, 2022. *Id.* at 3.
[146] Exs. 26, 26-ES (Stevens direct) at attached Scheds. 1, 2.
[147] The Petition calculates pre- and post-commercial operation dates amounts because nine Rider CE projects are expected to begin operations during the rate year. Ex. 27 (Lecky direct) at 10 (listing the nine projects).
[148] Exs. 27, 27-ES (Lecky direct) at 17, attached Scheds. 1-6. In addition to her testimony, Ms. Lecky sponsored or co-sponsored Filings Schedules 3-5, and 8, and parts of Filing Schedule 46F and the RPS Development Plan. *Id.* at 3.
[149] Ms. Lecky also separately calculated a PPA revenue requirement for the rate year. Ex. 27 (Lecky direct) at attached Sched. 6.
[150] *Id.* at 4-5.
[151] *Id.* at 5-6.

Site	Prior COD	New COD
CE-1 Solar Projects		
Grassfield Solar	8/1/2022	10/20/2022
Norge Solar	7/1/2023	10/1/2023
Sycamore Solar	11/1/2022	3/30/2023
CE-2 Projects		
Camelia Solar	10/1/2023	4/1/2024
Dulles Solar	12/1/2024	10/1/2026
Walnut Solar	12/1/2024	1/1/2025
Fountain Creek Solar	12/1/2023	7/1/2024
Otter Creek Solar	12/1/2023	5/1/2024
Piney Creek Solar	12/1/2023	8/15/2023
Quillwort Solar	10/1/2023	2/1/2024
Sebera Solar	10/1/2023	2/1/2024
Solidago Solar	6/1/2023	8/1/2023
Sweet Sue Solar	10/1/2023	2/1/2026
Winterberry Solar	10/1/2023	9/1/2023
Winterpock Solar	10/1/2023	4/1/2024
Black Bear Distributed Solar	12/1/2022	9/1/2023
Springfield Distributed Solar	12/1/2022	7/1/2024
Dry Bridge Storage	12/1/2022	12/1/2023
Dulles Storage	12/1/2024	5/1/2026
CE-3 Projects[1]		
Ivy Landfill Distributed Solar	12/1/2023	6/1/2025
Racefield Distributed Solar	11/1/2023	8/1/2025

Ms. Lecky's revenue requirement calculations incorporate three rates of return on common equity. She used the 9.7% return prescribed by 2023 legislation for the period beyond February 29, 2024. She used the 9.35% return approved in Case No. PUR-2021-00058, for November 18, 2021, to February 29, 2024. For the period prior to November 17, 2021, her calculations incorporate the 9.2% return in Case No. PUR-2019-00050.[152]

Pursuant to the "costs and benefits" framework approved by the *2020 RPS Plan Order*, Ms. Lecky's proposed revenue requirement includes estimated energy benefits for the Rider CE Projects and Rider CE PPAs. She allocated estimated energy benefits on an energy-only basis, per the *2020 RPS Plan Order*.[153] Ms. Lecky's proposed revenue requirement does not include any REC benefits because Dominion does not plan to retire any RECs produced by the Rider CE projects or the Rider CE PPAs during the rate year. Pursuant to the *Proxy Value Order*,[154] Ms. Lecky's revenue requirement does not include any estimated capacity value.[155]

[152] *Id.* at 7.
[153] *Id.* at 9.
[154] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing a proceeding concerning the allocation of RPS-related costs and the determination of certain proxy values for Virginia Electric and Power Company*, Case No. PUR-2021-00156, Final Order (June 13, 2023) ("*Proxy Value Order*").
[155] Ex. 27 (Lecky direct) at 8-9.

Ms. Lecky confirmed that Dominion will claim federal tax credits for the Company-owned Rider CE Projects. Her revenue requirement calculations for such projects include production tax credits and investment tax credits as established by the Inflation Reduction Act.[156]

Ms. Lecky represented that none of the costs requested in the instant case will be requested for recovery in any other proceeding. She confirmed that no indirect expenses, including service company expenses, are requested for recovery in this case. However, she indicated that certain service company costs are appropriately capitalized to Rider CE Projects and will be recovered as depreciation expense through the rate adjustment clause over the projects' useful lives.[157]

Ms. Lecky confirmed that the proposed revenue requirement includes financing costs for Peppertown and Alberta that begin accruing in August 2023 as if those costs had been incurred then.[158]

Mr. Hewett sponsored the proposed Rider CE, based on the proposed revenue requirement presented by Ms. Lecky.[159] He explained the Company's proposed allocation of Rider CE to the Virginia jurisdiction and customer classes, which uses Factor 1 to allocate demand-related costs and benefits (capacity) and Factor 3 to allocated energy-related costs and benefits (energy, RECs).[160] Mr. Hewett testified that the rates proposed by the instant Petition were calculated using the same methodology approved in the *2022 RPS Plan Order* and the *2022 Rider PPA Order*.[161]

Mr. Hewett identified the customer impact of the Petition's proposed Rider CE increase.[162] As proposed, the monthly bill of a residential customer using 1,000 kWh would increase by $1.54.[163] The proposed residential Rider CE rate is 0.2952¢/kWh,[164] which equates to a monthly Rider CE charge of approximately $2.95 for a residential customer using 1,000 kWh.

Dominion – Supplemental Direct Testimony

Dominion offered the supplemental direct testimony of **Mr. Gaskill.** He provided alternative RPS compliance obligation calculations for compliance years 2021 and 2022, because of discovery requests from Staff "suggesting that the retail sales component of this calculation

[156] *Id.* at 9.
[157] *Id.* at 16. Indirect or allocated service company expenses would be included in Dominion's base rates. Incremental sales and use taxes will be recovered through Dominion's annual sales and use tax surcharge. *Id.* at 17.
[158] Tr. at 173-75 (Lecky).
[159] Ex. 28 (Hewett direct) at 2 and attached Sched. 2. Mr. Hewett also sponsored Filing Schedule 46G and parts of the RPS Development Plan. *Id.* at 2-3.
[160] *Id.* at 3 and attached Sched. 4.
[161] *Id.* at 5 (citing *Petition of Virginia Electric and Power Company, For revision of a rate adjustment clause, designated Rider PPA, under § 56-585.1 A 5 d of the Code of Virginia, for the Rate Year commencing September 1, 2023*, Case No. PUR-2022-00202, Final Order (July 7, 2023) ("*2022 Rider PPA Order*")).
[162] Ex. 28 (Hewett direct) at attached Sched. 3.
[163] *Id.* at 8.
[164] *Id.* at attached Sched. 2 (Rate Schedule 1).

should be based on data publicly reported by the Company in other forums." Mr. Gaskill agreed with such an approach, finding it reasonable and more transparent for auditing purposes. He specifically recommended using FERC Form 1 data, where possible.[165]

Mr. Gaskill identified the steps his alternative approach used to calculate "total electric energy," as defined by Code § 56-585.5 A. First, retail sales were pulled from the relevant FERC Form 1 for jurisdictional and non-jurisdictional customers. For jurisdictional customers, sales numbers were pulled for Dominion's residential, commercial, and industrial customers, the latter of which he indicated excludes Micron. For non-jurisdictional customers, sales numbers were pulled for street and traffic and public authority, which he indicated include Micron and also the Virginia Municipal Electric Association ("VMEA"). Then, sales by competitive service providers to customers in Dominion's service territory were pulled from the Company's internal system, since such information is not reported on Dominion's FERC Form 1.[166]

Next, he described how his alternative calculations remove the statutory offsets for nuclear generation, ARBs, and certain large shopping customers with demand exceeding 100 MW in 2019, from the "total electric energy." Dominion's total nuclear generation for the given year for the Company-owned portions of North Anna and Surry was pulled from FERC Form 1. He then applied a Virginia percentage of this output from FERC 1 data. For ARBs, the alternative approach continued to use information from the Commission's certification process. For the large shopping customers, actual account data was used.[167]

Mr. Gaskill presented the following results from his alternative calculations, side-by-side with the 2022 Compliance Report figures presented with the Petition (Table 1) and the 2021 Compliance Report figures presented in the 2022 RPS Plan Case (Table 2).[168]

Table 1: Updated 2022 RPS Program Requirement

	As Filed in Case No. PUR-2023-00142	Supplemental Direct
Retail Sales – Jurisdictional	74,045,063	74,323,649
Retail Sales – Non-jurisdictional	12,295,216	12,266,541
Retail Sales Subtotal	**86,340,279**	**86,590,190**
Nuclear Output	25,462,128	25,518,383
Exempt Customer Load	6,068,477	6,068,477
"Total Electric Energy"	**54,809,674**	**55,003,330**
Percentage	17%	17%
Requirement (RECs)	**9,317,645**	**9,350,566**
1% Carve Out	93,176	93,506

[165] Ex. 29 (Gaskill supplemental direct) at 2.
[166] *Id.* (identifying VMEA as a full requirements customer of Dominion). Mr. Gaskill sponsored Dominion's agreements with VMEA, Micron, Craig Botetourt Electric Cooperative ("Craig Botetourt"), and the City of Manassas. Exs. 30, 31-ES, 32, 33-ES-Code of Conduct, and 34.
[167] Ex. 29 (Gaskill supplemental direct) at 2-3.
[168] *Id.* at 4-5.

Table 2: Updated 2021 RPS Program Requirement

	As Filed in Case No. PUR-2022-00124	Supplemental Direct
Retail Sales – Jurisdictional	68,404,714	70,888,587
Retail Sales – Non-jurisdictional	12,180,704	12,522,648
Retail Sales Subtotal	**80,585,418**	**83,411,235**
Nuclear Output	26,886,505	26,917,620
Exempt Customer Load	890,801	890,801
"Total Electric Energy"	**52,808,112**	**55,602,814**
Percentage	14%	14%
Requirement (RECs)	**7,393,136**	**7,784,394**
1% Carve Out	73,931	77,844

Mr. Gaskill confirmed that his alternative calculations do not include any adjustment for RECs retired: (1) by competitive service providers on behalf of their customers; or (2) by Dominion on behalf of Rider TRG customers. He indicated that Dominion intends to incorporate into its calculations, as appropriate, any Commission decisions from a separate, "standalone" proceeding directed by the Commission on these issues.[169]

According to Mr. Gaskill, Dominion has not retired any additional RECs based on its alternative calculations for compliance years 2021 and 2022. To avoid incurring potentially unnecessary costs, Dominion proposes making any adjustments needed for compliance – whether that may be retiring additional RECs or applying previously retired RECs to the Company's obligations in future compliance years – once the standalone proceeding has concluded. He pointed out that any adjustments from the standalone proceeding could offset any REC deficit for compliance years 2021 and 2022.[170]

Appalachian Voices Testimony

Appalachian Voices offered the testimony of **Gregory L. Abbott,** a consultant working as a sole proprietor.

Mr. Abbott recognized that the modeling assumptions, constraints, and inputs from Dominion's 2023 IRP are the same as those used for the 2023 RPS Development Plan.[171] He identified several aspects of Dominion's 2023 IRP and modeling that he challenged in the 2023

[169] *Id.* at 5. *See Petition of Appalachian Power Company, For approval of its 2023 RPS Plan under § 56-585.5 of the Code of Virginia and related requests,* Case No. PUR-2023-00001, Final Order at 13 (Sep. 7, 2023) ("*2023 APCo RPS Plan Order*") ("On or before January 16, 2024, APCo and Dominion shall make a filing, either jointly or separately, containing the proposed treatment of RECs associated with (i) customers taking service under each [utility's] voluntary renewable tariffs and (ii) shopping customers purchasing 100 percent renewable energy, for purposes of RPS Program compliance. Such filing shall include any associated proposal for netting the benefits of such RECs, including applicable tariff language."). The standalone proceeding initiated by Dominion has been docketed as Case No. PUR-2024-00010.

[170] Ex. 29 (Gaskill supplemental direct) at 5-6.

[171] Ex. 35 (Abbott) at 4.

IRP Case.[172] Mr. Abbott recommended that any Commission guidance on such issues from the 2023 IRP Case, in addition to any Commission directives in the instant case, should be reflected in Dominion's next development plan filing.[173] He indicated that the while the IRP and RPS proceedings are separate and different, the IRP informs the RPS and thus the outcomes of these proceedings are interrelated.[174]

Mr. Abbott discussed the following issues that he indicated are pending in Dominion's 2023 IRP Case: (1) modeling assumptions for ARBs; and (2) Dominion's capacity price forecast.[175] Mr. Abbott provided the following table to illustrate Dominion's progress on meeting the interim development requirements, which he indicated do not include the proposed CE-4 Projects or PPAs.[176]

	Cumulative 585.5 D Petition Requirements MWs (a)	**585.5 G ARB Offsets MWs (b)**	**Updated 585.5 D Petition Requirements MWs (c) = (a) - (b)**	**Company Owned In-Service or Proposed Through 2022 MWs (d)**	**Third-Party PPAs In-Service or Proposed Through 2022 MWs (e)**	**Total In-Service or Proposed Through 2022 MWs (f) = (d) + (e)**	**Remaining 585.5 D Petition Requirements MWs (g) = (c) - (f)**
2024	3,000	1,972	1,028	2,971	1,436	4,407	(3,379)
2027	6,000	1,972	4,028	2,971	1,436	4,407	(379)
2030	10,000	1,972	8,028	2,971	1,436	4,407	3,621
2035	16,100	1,972	14,128	2,971	1,436	4,407	9,721

Because he believes Dominions had already exceeded the Code § 56-585.5 D petition requirements for 2024 and 2027 before filing its Petition, Mr. Abbott concluded that there was no pressing need for Dominion to propose (nor a pressing need for the Commission to approve) the CE-4 Projects and PPAs based on meeting the interim statutory petition requirements.[177]

Referencing his column (b) in the above table, Mr. Abbott argued that it is not reasonable to assume that the amount of solar and onshore wind capacity under contract with bundled ARBs will remain a constant 1,972 MWs through 2035. In support of his argument, he indicated that 98.7% of ARB load is currently data center load and Dominion's forecast of data center load growth is 10.2% per year. He added that, from June 30, 2022, to June 30, 2023, capacity from certified ARBs increased from 1,301 MWs to 1,972 MWs – a 51.6% increase in only one year.[178]

[172] *Id.* at 2-4.
[173] *Id.* at 5.
[174] *Id.* at 6.
[175] *See, e.g., id.* at 8-13, 19-24.
[176] *Id.* at 9.
[177] *Id.*
[178] *Id.* at 9-10.

Mr. Abbott provided the following table to show the impact that assuming ARB offsets grow at the same rate as Dominion's forecast for data center load growth would have on Dominion's remaining interim statutory petition requirements.[179]

	Cumulative 585.5 D Procurement Requirements MWs (a)	585.5 G ARB Offsets MWs (b)	Updated 585.5 D Procurement Requirements MWs (c) = (a) - (b)	Company Owned In-Service or Proposed Through 2022 MWs (d)	Third-Party PPAs In-Service or Proposed Through 2022 MWs (e)	Total In-Service or Proposed Through 2022 MWs (f) = (d) + (e)	Remaining 585.5 D Procurement Requirements MWs (g) = (c) - (f)
2024	3,000	2,172	828	2,971	1,436	4,407	(3,579)
2027	6,000	2,904	3,096	2,971	1,436	4,407	(1,311)
2030	10,000	3,882	6,118	2,971	1,436	4,407	1,711
2035	16,100	6,298	9,802	2,971	1,436	4,407	5,395

He asserted that assuming a reasonable growth rate for ARB offsets "further diminishes the urgency of approving" the CE-4 Projects and PPAs for purposes of meeting the interim statutory petition requirements.[180] Mr. Abbott did not find it logical that an ARB would go to the trouble to certify a facility under a 20-year PPA one year, then decide to decertify that facility the next year.[181]

Notwithstanding his position on ARBs, Mr. Abbott testified that the RECs produced from the CE-4 Projects and PPAs are needed to satisfy the mandatory RPS requirements. However, in his opinion, Dominion should do more to explore meeting the mandatory RPS requirements with unbundled REC purchases in future RPS plan filings.[182]

Mr. Abbott described Dominion's load growth forecast used in its 2023 IRP and the instant RPS plan Petition as highly uncertain due to uncertainties regarding data center load growth and the proportion of such load growth that will elect the ARB option. He believes these risks could be mitigated to some extent by relying more heavily on unbundled REC purchases. He pointed out that unlike the 35% statutory limitation on PPAs, there are no petition restrictions "on satisfying the RPS Program requirements with qualifying unbundled RECs."[183] Mr. Abbott believes that "Dominion should be encouraged to purchase and bank RECs from the spot market whenever it makes sense to do so" but "Dominion cannot rely on an assumption that there will be an unlimited supply of available qualifying RECs for purchase on the spot market throughout the planning period."[184] Accordingly, Mr. Abbott recommended that the Commission direct Dominion to proactively seek out long-term purchase agreements for unbundled RECs, for example: (i) through a separate RFP; (ii) as a mandatory component of the Company's existing RFPs for PPAs; or (iii) through follow up outreach by Dominion with bidders in Dominion's PPA RFPs that are not selected due to the statutory 35% restriction.[185]

---

[179] *Id.* at 11.
[180] *Id.* at 12.
[181] Tr. at 206-07 (Abbott).
[182] *Id.* at 12.
[183] *Id.* at 13-14.
[184] *Id.* at 14-15.
[185] *Id.* at 15-16. As described by Mr. Abbott, bidders in the PPA RFPs could be required to offer unbundled REC-only prices in addition to bundled PPA prices. *Id.*

Mr. Abbott acknowledged that developers may not be willing to make offers for long-term purchase agreements for unbundled RECs and that any such offers may not be at attractive prices. However, he believes pursuing a strategy of executing such agreements would promote new renewable resources in the Commonwealth at a potentially lower cost to ratepayers.[186]

According to Mr. Abbott, the CE-4 Projects and PPAs may not achieve fuel savings for ratepayers. He explained that the energy generated by these projects and PPAs would be zero-variable cost and therefore would displace energy from the marginal generation unit in PJM's regional economic dispatch, which would likely be a coal unit or an older gas-fired unit. Mr. Abbott asserted that the CE-4 Projects and PPAs would create fuel savings only if the marginal generation units that they displace are Dominion-owned generation units. He clarified that this point refers to fuel factor costs.[187] He finds it unlikely that Dominion's nuclear or its modern gas-fired units would be marginal units displaced by CE-4 Projects or PPAs generation and indicated that Dominion's practice of self-scheduling coal units as must-run dispatch will diminish fuel savings from coal units that could otherwise be realized. He believes significant fuel savings could be accomplished by retiring Dominion's coal units earlier than the dates Dominion assumed in its 2023 IRP alternative plans.[188]

He explained that Dominion's modeling assumes an inverse relationship between energy and capacity prices. The combination of a high capacity price forecast and low energy price forecast produces higher net benefits for peaking resources, such as gas combustion turbines and energy storage. In contrast, a low capacity price forecast with a higher energy price forecast could produce higher net benefits for intermittent renewable resources.[189] Mr. Abbott discussed testimony in the 2023 IRP Case and indicated that he does not consider Dominion's low capacity price sensitivity in that case to be useful. He indicated that, in the instant case, the net present values for the CE-4 Projects and PPAs would likely be higher under a low capacity price (higher energy price) sensitivity. He recommended that the Commission require Dominion to perform an economic analysis for all future CPCNs (for both renewable resources and traditional dispatchable resources) that uses a realistic low capacity price forecast sensitivity.[190]

Mr. Abbott echoed his position in the 2023 IRP Case that Dominion should perform a locational analysis, especially for energy storage resources, given that Dominion's forecasted load growth is almost exclusively driven by data centers, 80% of which are located in Northern Virginia.[191] He indicated that he "cannot emphasize enough the importance of factoring in the potential location benefits in the selection process" for projects.[192] He recommended that the Commission direct Dominion to study this issue and to develop protocols for the solicitation and

[186] *Id.* at 16.
[187] *Id.* at 17; Tr. at 201-04 (Abbott).
[188] Ex. 35 (Abbott) at 18-19.
[189] *Id.* at 20.
[190] *Id.* at 20-24.
[191] *Id.* at 24-31.
[192] *Id.* at 30.

procurement process that steer and encourage energy storage resources to be located in nodal areas that are projected to have an imbalance between energy supply and energy demand.[193]

Mr. Abbott disagreed that this issue should be deferred because no CE-4 storage facilities or PPAs are proposed by the Petition. He indicated it may be preferable to raise this issue now so that Commission guidance can be incorporated into future petitions proposing such resources.[194] He believes incorporating locational value in long-term modeling is an issue for IRP cases, but that the use of locational value in economic analysis performed for project evaluation and in support of specific resources are issues for RPS plan cases.[195] Even if the Commission does not require Dominion to modify PLEXOS in the Company's long-term modeling, Mr. Abbott believes the economic analysis performed for resources proposed in RPS plan cases could address variances and locational benefits. He offered as an example that Dominion could forecast on-peak and off-peak nodal locational marginal energy prices and use the appropriate nodal values in a spreadsheet analysis, rather than assuming all energy storage resources will discharge and recharge at the same weighted average locational marginal energy prices.[196]

Mr. Abbott indicated there is time for Dominion to study this issue since, although the Code requires Dominion to petition for approval to construct or acquire 2,700 MWs of energy storage capacity by December 31, 2035, he indicated there are no interim goals before 2035. He cautioned that a "fleet of 2,700 MW of energy storage resources located in the wrong locations will not enhance the reliability and performance of Dominion's generation and distribution system."[197]

Mr. Abbott opposed the Petition's proposed consolidation of Riders CE and PPA. In his view, consolidation would reduce transparency for customers on their monthly bills. He asserted that the solar PPAs approved to date are lowering customers' monthly bills and he believes this would be hidden from customers with consolidation. It makes sense to him to maintain the statutory distinction between Dominion-owned and third-party resources by recovering such costs through separate rate adjustment clauses.[198] He would not object to consolidation so long as ratepayers can see the bill impact from Company-owned projects distinct from that of PPAs in customer bills and in Commission reports to the General Assembly.[199]

---

[193] *Id.* at 31. Mr. Abbott indicated that because Dominion's PLEXOS model is not currently configured to perform locational analysis, Dominion would likely need to consult with Energy Exemplar to acquire an additional module to the PLEXOS model that would enable an optimized locational analysis. *Id.*

[194] Tr. at 192-93 (Abbott).

[195] Tr. at 193-94 (Abbott). In the instant case, the net present value economic analysis Dominion used to select CE-4 PPAs is the same as the analysis submitted in support of such PPAs. Tr. at 137-38 (Keefer).

[196] Tr. at 196-97 (Abbott).

[197] Ex. 35 (Abbott) at 31.

[198] *Id.* at 32-33.

[199] Tr. at 213-15 (Abbott).

DEQ Report

In the DEQ Report, DEQ identified the permits and approvals three of the CE-4 Projects – Beldale, Blue Ridge, and Michaux – likely would require.[200] The DEQ Report also made recommendations based on information and analysis submitted by reviewing agencies regarding these three projects. DEQ's recommendations, which are in addition to requirements of federal, state, or local law or regulations listed above, are summarized below.[201]

- Conduct an on-site delineation of all wetlands and stream crossings within the project area with verification by the U.S. Army Corps of Engineers, using accepted methods and procedures, and follow DEQ's recommendations to avoid and minimize impacts to wetlands and streams.
- Reduce solid waste at the source, reuse it and recycle it to the maximum extent.
- Coordinate with Department of Conservation and Recreation Division of Natural Heritage ("DCR-DNH") on its recommendations for vegetation management and invasive species management plans, plant inventory, riparian buffers, and protections for bats and other natural heritage resources, ecological cores, and project updates.
- Coordinate with the Department of Forestry ("DOF") regarding its recommendations for compensating for unavoidable clearance of forestland.
- Coordinate with the Virginia Department of Wildlife Resources on recommendations for listed species, a mussel survey, instream activities, solar facilities guidance, forest fragmentation and other protections for wildlife resources.
- Coordinate with the Virginia Outdoors Foundation ("VOF") for additional review if necessary.
- Coordinate with the Virginia Department of Health on its recommendation to implement best management practices and manage materials onsite as necessary.
- Follow the principles and practices of pollution prevention to the maximum extent practicable.
- Limit the use of pesticides and herbicides to the extent practicable.

Staff Testimony

Staff presented the results of its investigation through the testimonies of **Arwen T. Otwell** and **Alexander W. Elmes**, Utility Specialists with the Commission's Division of Utility Accounting and Finance; **Bernadette Johnson**, General Manager, Power & Renewables, for Enverus, Inc. ("Enverus"); **Tanner R. Brunelle**, **Matthew S. Glattfelder**, and **Amanda A. Ricketts**, Public Utility Regulation Analysts with the Commission's Division of Public Utility Regulation ("PUR"); and **Matthew B. C. Unger**, Senior Public Utility Regulation Analyst with PUR.

---

[200] Ex. 42 (DEQ Report) at 3-5. Dominion did not seek CPCNs for Peppertown or Alberta because their capacities are 5 MW or less. *See, e.g.,* Ex. 11 (Flowers direct) at 7 and attached Sched. 10. Dominion has already received a DEQ permit by rule for Bookers Mill, as discussed further in Section II of this Report's Analysis.
[201] Ex. 42 (DEQ Report) at 6-7.

Ms. Otwell described the components of Rider CE and Rider PPA. These components include a projected factor and true-up factor.[202]

Ms. Otwell discussed the Company's consolidated bill impact analysis directed by the *2020 RPS Plan Order*. She presented the following table to summarize future annual RPS bill impacts on a residential customer using 1,000 kWh/month, based on the Company's Alternative Plan B from its 2023 IRP, during three points in time (2023, 2030, 2035).[203]

TABLE 1

Alternative Plan B: Residential (Schedule 1) RPS Bill Impact for 2023, 2030, and 2035

Includes Riders RPS, OSW, and CE.

		2023 IRP		2023 RPS Development Plan	
Line No.	Year	Monthly Bill Impact*	Annual Bill Impact	Monthly Bill Impact**	Annual Bill Impact
1	2023	$ 7.68	$ 92.16	$ 7.46	$ 89.52
2	2030	$ 29.22	$ 350.64	$ 32.67	$ 392.04
3	2035	$ 45.09	$ 541.08	$ 51.89	$ 622.68

While Ms. Otwell did not take issue with the Company's bill impact analysis, she cautioned that this analysis may not be definitive because the Company's future resources may be deployed or modeled in a different manner than presented in this proceeding.[204] Ms. Otwell explained how Dominion's bill impact analysis incorporated the effects of the Inflation Reduction Act, while noting that final tax credit decisions are made on a project-specific basis as the applicable projects reach commercial operations.[205] She also identified the assumptions Dominion changed from the analysis presented in the 2022 RPS Plan Case.[206]

Ms. Otwell calculated Staff's recommended $135.165 million revenue requirement, which is $1.51 million lower than the Company's proposed revenue requirement.[207] She explained that Staff found formulaic errors, the correction of which lowered the revenue requirement by $1.95 million. Staff also incorporated changes to lead/lag days that increased the revenue requirement by $433,548.[208] She presented Staff's rate year revenue requirements, which, for the Company-owned projects are broken down by project.[209]

---

[202] Ex. 36 (Otwell) at Appendix A.

[203] *Id.* at 7 (asterisked citations omitted).

[204] *Id.* at 6.

[205] *Id.* at 8-9, n.10.

[206] *Id.* at 5.

[207] *Id.* at 10-11, Statements 1 and 2.

[208] *Id.* at 12-13. She indicated that future true-ups can incorporate any difference in lead/lag days resulting from the Commission's Final Order in Case No. PUR-2023-00094. *Id.* at 13 (referencing *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider GV, Greensville County Power Station, for the rate years commencing April 1, 2024, and April 1, 2025*, Case No. PUR-2023-00094).

[209] Ex. 36 (Otwell) at Statement 1. As shown, the PPA revenue requirements are not broken down by project/agreement.

240230001

Virginia Electric and Power Company
Total Rider CE Revenue Requirements
Dollar Amounts in 000s
For the Rate Year May 01, 2024 to April 30, 2025

Description	Project Amount	Total
CE-1 Projects		
CE-1 Grassfield Solar	$ 852	
CE-1 Norge Solar	$ 792	
CE-1 Sycamore Solar	$ 4,333	
Total CE-1 Projects Revenue Requirement		$ 5,977
CE-2 Projects		
CE-2 Camellia Solar	$ 685	
CE-2 Dulles Solar	$ 20,717	
CE-2 Fountain Creek Solar	$ 198	
CE-2 Otter Creek Solar	$ (150)	
CE-2 Piney Creek Solar	$ 5,213	
CE-2 Quillwort Solar	$ 642	
CE-2 Sebera Solar	$ 908	
CE-2 Solidago Solar	$ 820	
CE-2 Sweet Sue Solar	$ 8,473	
CE-2 Walnut Solar	$ 8,844	
CE-2 Winterberry Solar	$ 1,020	
CE-2 Winterpock Solar	$ 1,274	
CE-2 Black Bear Distributed Solar	$ 520	
CE-2 Springfield Distributed Solar	$ 285	
CE-2 Dry Bridge Storage	$ 3,722	
CE-2 Dulles Storage	$ 3,876	
Total CE-2 Projects Revenue Requirement		$ 57,046
CE-3 Projects		
CE-3 Bridleton Solar	$ 1,596	
CE-3 Cerulean Solar	$ 8,130	
CE-3 Courthouse Solar	$ 13,333	
CE-3 Kings Creek Solar	$ 833	
CE-3 Moon Corner Solar	$ 6,493	
CE-3 North Ridge Solar	$ 1,754	
CE-3 Southern VA Solar	$ 16,497	
CE-3 Ivy Landfill Distributed Solar	$ 609	
CE-3 Racefield Distributed Solar	$ 557	
CE-3 Shands Storage	$ 3,126	
Total CE-3 Projects Revenue Requirement		$ 52,928
CE-4 Solar		
CE-4 Beldale	$ 7,102	
CE-4 Blue Ridge	$ 11,099	
CE-4 Booker's Mill	$ 19,184	
CE-4 Michaux	$ 3,882	
CE-4 Peppertown	$ 1,129	
Total CE-4 Solar Revenue Requirement		$ 42,397
CE-4 Distributed Solar		
CE-4 Alberta	$ 751	
Total CE-4 Distributed Solar Revenue Requirement		$ 751
PPAs		
Total PPA Projected Factor Revenue Requirement		$ (9,163)
True-Up Rate Base Projected Factor Revenue Requirement		$ (510)
Total Projected Cost Recovery Factor		**$ 149,425**
True-Up		
CE Projects Actual Cost True-Up Factor	$ (16,004)	
PPA Projects Actual Cost True-Up Factor	$ 1,744	
Total Actual Cost True-Up Factor		**$ (14,260)**
Total Rate Year Revenue Requirement		**$ 135,165**

Ms. Otwell reported the results of Staff's review of Dominion's cost projections and the Company's 2022 actual costs and revenue recoveries. Staff did not take further issue with the Company's projections or discover any material discrepancies in this year's audit of Rider CE.[210] She testified that Staff will audit PPA expenditures as more of the underlying facilities come online.[211]

Ms. Otwell presented the $2.62 billion total Rider CE remaining lifetime revenue requirement calculated by Staff, and inclusive of PPAs, with the following table.[212]

TABLE 3
CE Solar & Storage Projects Long-Term Revenue Requirement (In Thousands)

Line No.	Description	Amount	Total
	CE-1 Projects		
1	Total CE-1 Projects Lifetime Revenue Requirement		$ 52,909
2	*CE-2 Projects*		
3	Total CE-2 Projects Lifetime Revenue Requirement		$ 831,876
4	*CE-3 Projects*		
5	Total CE-3 Projects Lifetime Revenue Requirement		$ 779,179
6	*CE-4 Solar*		
7	CE-4 Beldale	$ 122,479	
8	CE-4 Blue Ridge	$ 259,400	
9	CE-4 Bookers Mill	$ 81,849	
10	CE-4 Michaux	$ 120,755	
11	CE-4 Peppertown	$ 11,582	
12	Total CE-4 Solar Lifetime Revenue Requirement		$ 596,064
13	*CE-4 Distributed Solar*		
14	CE-4 Alberta DER	$ 9,487	
15	Total CE-4 Distributed Solar Lifetime Revenue Requirement		$ 9,487
16	*PPA Projects*		
17	Total PPA Projects Lifetime Revenue Requirement		$ 353,698
18	**Total Lifetime Revenue Requirement**		**$ 2,623,213**

Ms. Otwell identified three reasons why Staff's lifetime revenue requirement calculation in this case for the CE-1, CE-2, and CE-3 Projects is approximately $1.2 billion higher than the calculation Staff presented in the 2022 RPS Plan Case. The three reasons she identified are: (1) removal of the capacity benefit from proxy values, consistent with the *Proxy Value Order* ($1.1 billion); (2) increase in the ROE, from 9.35% to 9.7% ($64 million); and (3) miscellaneous differences in costs and tax credits ($50 million).[213] Ms. Otwell acknowledged that the lifetime

[210] *Id.* at 13-14.
[211] Tr. at 237-38 (Otwell).
[212] Ex. 36 (Otwell) at 14. *See also id.* at Statements 49-53.
[213] *Id.* at 15. Staff's inclusion of the PPA Projects and CE-4 Projects, as shown in the above table, also increased Staff's lifetime revenue requirement compared to last year.

revenue requirement estimate for PPA projects is roughly 15% of Staff's total lifetime revenue requirement figure.[214]

Mr. Elmes addressed the capital structures and associated costs of capital used to calculate the Rider CE revenue requirement. For the true-up factors, Staff verified the capital structures and costs of capital proposed by Dominion and supported their use in this case.[215] For the projected factor, Staff accepted Dominion's proposed capital structure and costs of capital, subject to true up and the Commission's decision in the pending biennial review, Case No. PUR-2023-00101.[216]

Ms. Johnson sponsored a report that provided price and load forecasts prepared by Enverus and reviewed the Company's forecasts ("Enverus Report").[217] She summarized the findings of the Enverus Report as follows.[218]

<u>Forecast Comparison:</u>

- Forecasting in the current global environment has become increasingly difficult due to extraordinary global events resulting in extremely volatile commodity prices and consumption patterns that are largely unprecedented in the past 10 years. Therefore, differences in the forecasts are not surprising and can be expected.
    - For the 2023 RPS the Company utilized the same forecasts that were used in the 2023 IRP. Enverus has updated the forecasts it provided in the 2023 IRP (created in June 2023) with the forecasts included in this report (created in November 2023).
    - The Company's price forecasts rely on analysis provided by ICF … as of [February 28,] 2023.
    - The Company provides a robust and transparent discussion of its forecasting methodology in Chapter 4 of the 2023 IRP.
    - Per Section 4.4 – Commodity Price Assumptions, the Company utilizes a single source – ICF – to provide multiple scenarios for the commodity price forecasts to ensure consistency in methodologies and assumptions.
    - For most commodity prices, the Company uses forward market prices as of [February 28,] 2023 for the first 18 months, blended forward prices with ICF estimates for the next 18 months, and ICF forecasts exclusively beyond the first 36 months.
    - Forecasts for capacity and federal CO_2 prices are provided by ICF for all years forecasted within this 2023 Plan.
    - Enverus also uses a blend of market prices and analyst generated outlooks. The mixture of market and analyst outlooks varies depending on the reliability of the observable market and likely differs from that used by the Company, but both approaches represent best-efforts at identifying a reasonable outlook.

---

[214] Tr. at 231 (Otwell). \$353,698/\$2,623,213 = 13.5%.
[215] Ex. 38 (Elmes) at 2-3.
[216] *Id.* at 3.
[217] Ex. 39 (Johnson) at Attachment.
[218] *Id.* at 3-5.

- o Enverus agrees with the final statement of IRP Section 4.4: The commodity price forecasts analyzed in the 2023 Plan present reasonably likely outcomes given the current understanding of market fundamentals, but do not present all possible outcomes.
- o Enverus agrees with the approach of blending observable forward market prices when available and transparent because the inherent "crowd-sourcing" nature of forward markets is naturally resistant to a single analyst outlier viewpoint.

- Forecast accuracy relies upon the assumption that all available market data and events have been considered at the time of the forecast. Confidence declines with each passing month as new information is introduced.
- Therefore, while Enverus noted that the forecast date ([February] 2023) was reasonable for the IRP filing, it would be prudent to update this forecast which is nearing 6 months old.
- The Enverus forecasts were generated on or about [November 1,] 2023.

. . .

- Price Forecasts for both fuel and power prices between the Company and Enverus do differ but not in an unacceptable manner. Variances are mostly attributable to a difference in timing of when the forecasts were created. In addition, there are reasonable differences in the outlook for near-term effects of recent global volatility.

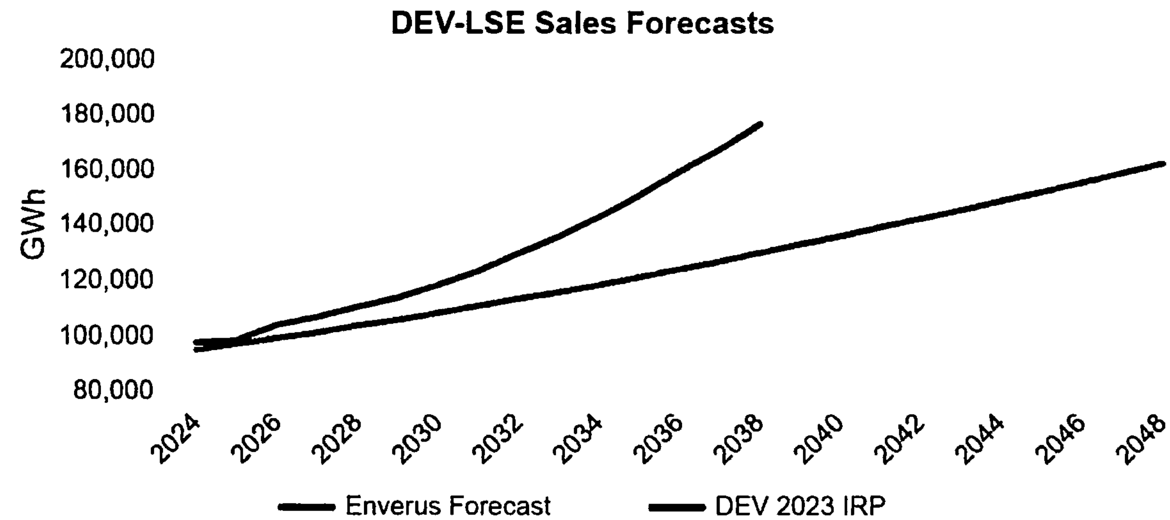
<u>Differences:</u>

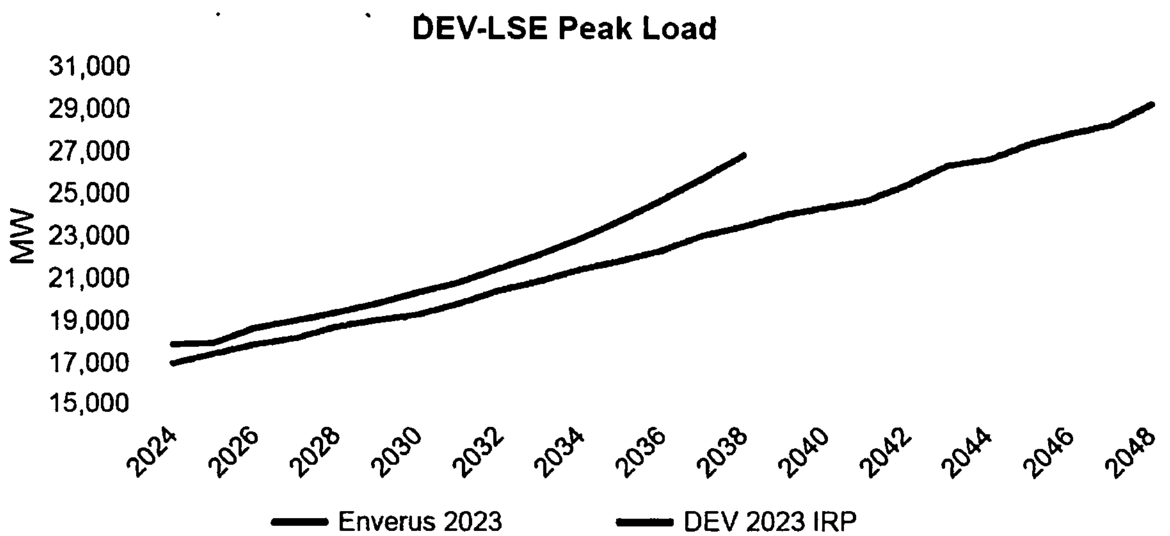
- The three areas where Enverus differs most from the Company are:
  - o Energy Sales and Peak Load forecasts;
  - o Capacity Price forecast; and
  - o REC Price forecast.
- ...Much of the differences originate from the newly optimistic load growth forecasts from both PJM and the Company.
- These forecasts are primarily driven by expectations of very large growth in data center load. While Enverus acknowledges this is a new phenomenon and deserves serious attention, our outlook forecasts a smaller amount of growth for reasons outlined in the report.

<u>Historical Forecast Performance:</u>

- When comparing actual prices to the Company's forecasts after the fact, the short-term portion of the forecasts are generally accurate.
- For IRPs filed more than 2-3 years ago, the trend across the long-term portion of both price and sales forecasts exhibited overly optimistic positive trajectories that were not supported by actual results.
- However, that pattern began to be corrected with recent IRPs (2021 and 2022) which appeared to have reasonable outlooks for both prices and sales.
- The onset of the data center debate appears to have disrupted this trend. Much uncertainty remains about what lies ahead. Enverus cautions against demand/sales forecasts that rely too heavily on one sector of demand; in this case the "commercial sector." Referencing the 2023 IRP Appendices (Tab 4A), the forecast for the DEV LSE indicates the Commercial sector will make up nearly 50% of demand by 2026 and 68% by 2038. No growth is projected for the Residential & Industrial segments.

The Enverus Report includes several illustrative comparisons of Enverus's energy and peak load forecasts with Dominion's. Two of those charts are shown below.[219]



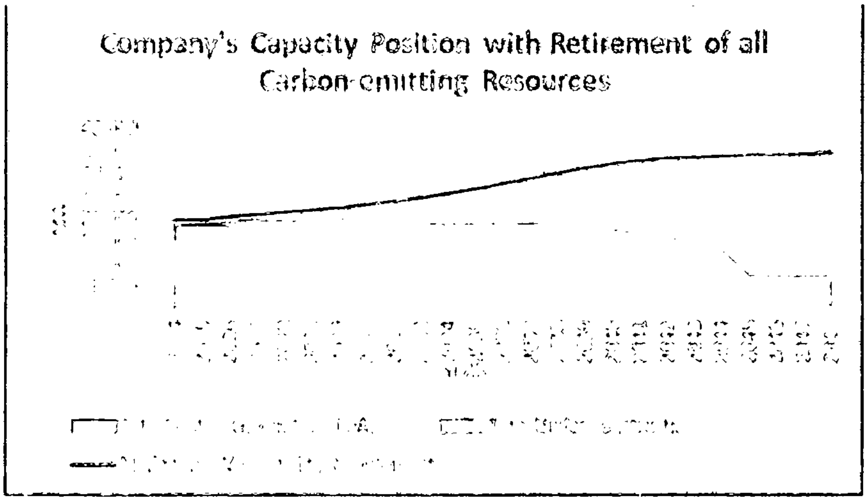


Mr. Brunelle summarized the VCEA's development targets and some of the associated information provided by the 2023 RPS Development Plan.[220]

Mr. Brunelle discussed charts provided by Company witness Flowers, some of which are included in Section II of this Report's Discussion below, illustrating the Company's projected energy, capacity, and REC positions – with and without the CE-4 Projects and PPAs.[221]

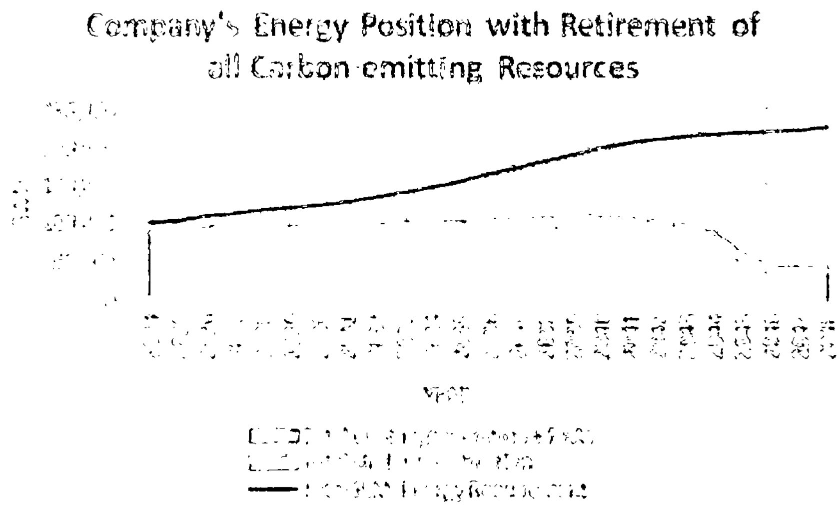
[219] *Id.* at Attachment, 17-18. The Enverus Report includes similar graphs for the DOM Zone, for summer non-coincident, summer coincident, and winter non-coincident peak load forecasts. *Id.* at 17-21.
[220] Ex. 37 (Brunelle) at 2-5. The 2023 RPS Development Plan is summarized above in this Report.
[221] *Id.* at 8-16.

Mr. Brunelle provided the following chart that Staff created to show the Company's capacity position with the retirement of all carbon-emitting generation units using Alternative Plan E from Dominion's 2023 IRP.[222]



As illustrated above, the forecasted capacity deficit with these retirements would be approximately 1,000 MW by 2024, 11,100 by 2038, and 27,600 MW by 2048.[223]

He also provided the following chart that Staff created to show the Company's energy position with the retirement of all carbon-emitting generation units using Alternative Plan E from Dominion's 2023 IRP.[224]



As shown above, the forecasted energy deficit with these retirements would be approximately 13,000 gigawatt-hours ("GWh") by 2024, 77,900 GWh by 2038, and 182,000 GWh by 2048.[225]

[222] *Id.* at 11.
[223] *Id.*
[224] *Id.* at 14. Staff did not create a comparable chart for Dominion's REC need. The retirement of carbon-emitting resources does not affect the REC need. *Id.* at 15, n.30.
[225] *Id.*

According to Mr. Brunelle, Dominion's modeling for the 2023 RPS Development Plan is consistent with the Company's modeling for its 2023 IRP. Mr. Brunelle identified the following areas of Staff concern with the Company's modeling that Staff raised in the pending 2023 IRP Case: (1) the average annual capacity factors of onshore wind resources used in the model; (2) the effective load carrying capability capacity values of solar resources used in the model; (3) the estimated construction costs/timelines of small modular nuclear reactors made available for selection in the model; (4) Dominion's energy, peak load, and commodities forecast; and (5) the modeling of 5% energy efficiency savings attributable to Dominion's current and projected demand side management activities. Mr. Brunelle recommended that the Commission order in the instant RPS Plan case incorporate any Commission directives from the 2023 IRP Case on these issues.[226]

Mr. Brunelle described Dominion's resource screening process to compile a "short list" of resources for which the Company uses PLEXOS modeling to allocate resource additions, by type and timing, in alternative plans. He indicated that Dominion made the following supply-side resources available for model selection: solar (distributed and utility-scale); wind (onshore and offshore); pumped storage; four-hour, lithium-ion battery storage; small modular nuclear reactors; capacity purchases; and natural gas (combined cycle and combustion turbine).[227] Mr. Brunelle provided more detail on parameters Dominion used for modeling each of these resources, including maximum annual limits, assumed capacity factors, and effective load carrying capabilities.[228]

For storage resources, Mr. Brunelle testified that Staff did not oppose Dominion's exclusion of longer duration resources. However, he noted that a Dominion proposal for an iron-air storage resource with a longer duration is pending in Case No. PUR-2023-00162. Staff recommended that Dominion be directed to continue to monitor available or developing energy storage technologies and refine its modeling assumptions in future RPS and IRP proceedings, particularly for technologies with which Dominion obtains experience.[229]

Mr. Brunelle testified that Staff did not oppose Dominion's assumed capacity values for solar resources, the effective load carrying capabilities for wind or storage resources, or capacity purchase limits used in the Company's modeling.[230] Staff did raise concerns in the 2023 IRP Case about Dominion's modeling of reductions to its energy and capacity needs resulting from its demand-side management programs, and the impact of capacity factors on REC assumptions.[231]

Mr. Brunelle discussed Dominion's construction cost assumptions used in its modeling, which Staff did not oppose.[232]

---

[226] *Id.* at 20.
[227] *Id.* at 20-22.
[228] *Id.* at 22-31.
[229] *Id.* at 27.
[230] *Id.* at 23-30.
[231] *Id.* at 31.
[232] *Id.*

According to Mr. Brunelle (and Staff witness Glattfelder), the purpose of Staff identifying in the instant case issues Staff raised in the pending 2023 IRP Case is to complete the record and provide context since Dominion's modeling methodology underlying both cases is the same. Staff did not plan to relitigate those issues. Rather, Staff recommended the Commission direct Dominion to model inputs in future RPS Plan cases consistent with the final order that will be entered in the 2023 IRP Case.[233]

Mr. Brunelle identified the Petition's proposal to consolidate Riders CE and PPA. He described the cost allocation and rate design proposed by the Petition. He represented that the cost allocation and rate design for Riders CE and PPA have no differences.[234] Staff does not oppose the proposed consolidation.[235]

Mr. Brunelle highlighted the $1.54 increase to a residential customer's monthly bill, assuming 1,000 kWh monthly usage, that would result from the Petition. If the Commission approves a revenue requirement different than proposed by the Petition, he recommended a proportionate adjustment to the corresponding surcharge.[236]

To the extent that Dominion continues to file RPS development plans that are substantively the same as IRPs, Mr. Brunelle initially recommended that the Commission require Dominion to file its IRP, including, at a minimum, the plan results and underlying workpapers and assumptions, "as part of the original RPS filing." However, he indicated that Dominion's proposal to post the IRP and Excel files for the associated appendices in the eRoom would address Staff's concerns.[237]

Staff witness **Glattfelder** addressed Dominion's modeling results. Mr. Glattfelder explained that Dominion used PLEXOS to complete two types of modeling: (1) long-term system modeling completed as part of the IRP process that was incorporated into the 2023 RPS Development Plan for reference, consistent with prior Commission orders; and (2) economic analysis for the specific projects and PPAs for which the Petition requests approval.[238]

Mr. Glattfelder identified the estimated net present values, resource additions, and retirements for Alternative Plans A, B, C, D and E,[239] which are identified above in this Report's Summary of the 2023 RPS Development Plan. He discussed the energy, capacity, and REC needs identified by the Company and reproduced illustrative charts from the Petition.[240] While Dominion proposed five plans in the instant case, Mr. Glattfelder described the three plans on

---

[233] *Id.* at 31-32; Ex. 40 (Glattfelder) at 3.

[234] Ex. 37 (Brunelle) at 34-38. Mr. Brunelle cited the following language from the *Proxy Value Order*: "It is reasonable and appropriate to use the same allocation methodology to allocate Company-owned resources and PPAs." *See Proxy Value Order* at 7. *See also* Ex. 37 (Brunelle) at Attachment TRB-1 (Dominion's response to Staff discovery request no. 3-96(c)).

[235] Tr. at 243 (Brunelle).

[236] Ex. 37 (Brunelle) at 38.

[237] *Id.* at 38-39; Tr. at 241-42 (Brunelle).

[238] Ex. 40 (Glattfelder) at 2.

[239] *Id.* at 6-23 and Attachments MSG-2, MSG-3, and MSG-4. Pages 7, 20, and 22 are among those revised during the course of this proceeding.

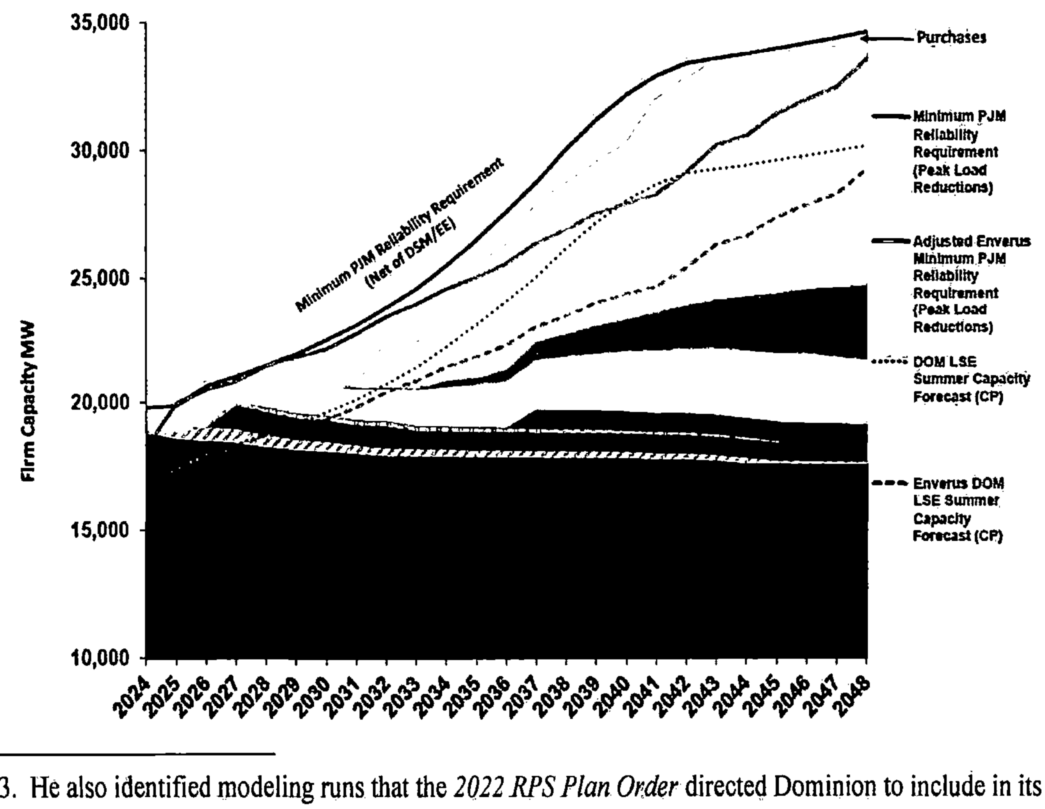
[240] *Id.* at 6-23.

which his testimony focused as follows:

> Alternative Plan A: the Company's least-cost plan to comply with the statutory REC retirement requirements (Code § 56-585.5 C).
>
> Alternative Plan B: the Company's least-cost plan that complies with the statutory REC retirement requirements (Code § 56-585.5 C) and achieves the statutory development targets for solar and wind (Code § 56-585.5 D) and for storage resources (Code § 56-585.5 E).
>
> Alternative Plan E: the Company's least-cost plan that complies with the statutory REC retirement requirements (Code § 56-585.5 C); statutory development targets (Code § 56-585.5 D and E); and the statutory requirement to retire all carbon-emitting generation units (Code § 56-585.5 B).[241]

Staff witness Johnson sponsored energy and capacity forecasts from Enverus that differ from Dominion's forecasts. Mr. Glattfelder indicated that in 2038, Enverus's capacity forecast and energy forecast are lower than the Company's by approximately 7,100 MW and 53,700 GWh, respectively.[242] He sponsored the following Staff graphs to show the Enverus forecasts overlaying Dominion's Alternative Plan A resource additions.[243]

Alternative Plan A, Enverus Forecast Overlay, Capacity (MW)



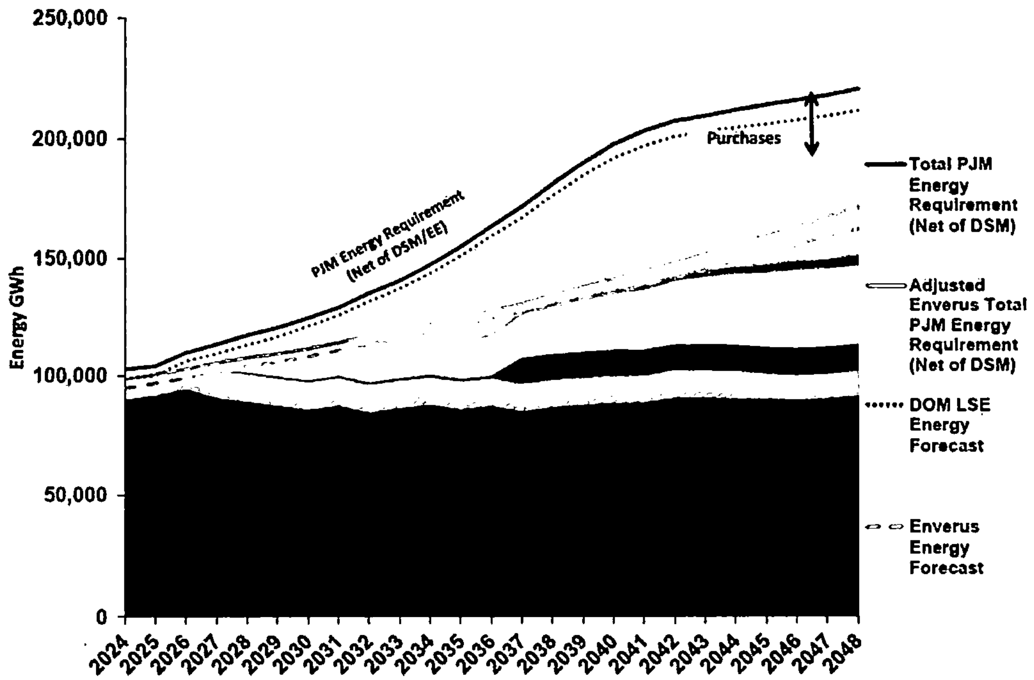
---

[241] *Id.* at 3. He also identified modeling runs that the *2022 RPS Plan Order* directed Dominion to include in its Petition. *Id.* at 4.

[242] *See, e.g., id.* at rev. 25-26. 30,550 – 23,459 = 7,091 MW. 183,544 – 129,886 = 53,658 GWh.

[243] *Id.* at 25-26.

Alternative Plan A, Enverus Forecast Overlay, Energy (GWH)



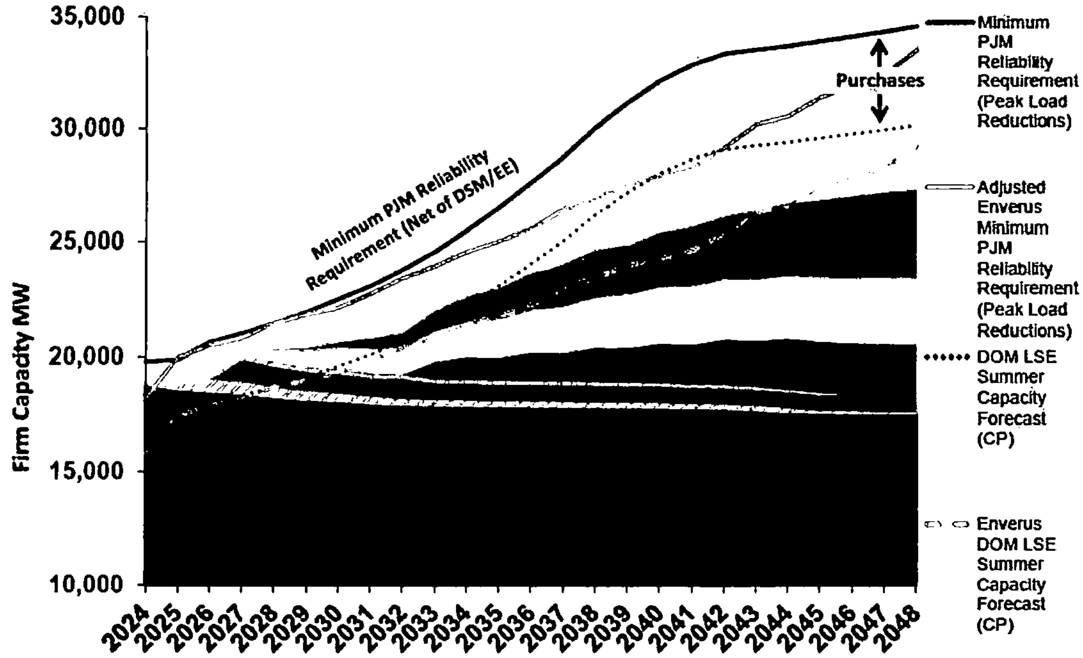
Mr. Glattfelder's testimony identifies the resources associated with the top four shaded areas on his Alternative Plan A tables as resources that are not existing or under construction. These areas depict – from top to bottom – new fossil (light brown); new storage (green); new solar (yellow); and new wind (light blue).[244]

According to Mr. Glattfelder, Dominion's Petition did not identify a "preferred plan," but he described Alternative Plan B as "the backbone to the RPS."[245] He recognized that Alternative Plan B does not meet the Company's REC needs through 2048, with a shortfall of RECs beginning in 2039 and growing thereafter.[246] A REC shortfall of approximately 2.4 million in 2039 grows to approximately 24 million by 2048 under this plan.[247] He sponsored the following Staff graph to show the Enverus capacity forecast overlaying Dominion's Alternative Plan B resource additions.[248]

---

[244] *Id.* at 7-9.
[245] *Id.* at 5.
[246] *Id.* at 15.
[247] *Id.* at 16.
[248] *Id.* at 27. Staff's energy forecast overlay for Alternative Plan B inadvertently included retirements that Dominion did not assume in this plan. *Id.* at 28; Tr. at 260-61 (Glattfelder).

Alternative Plan B, Enverus Forecast Overlay, Capacity (MW)



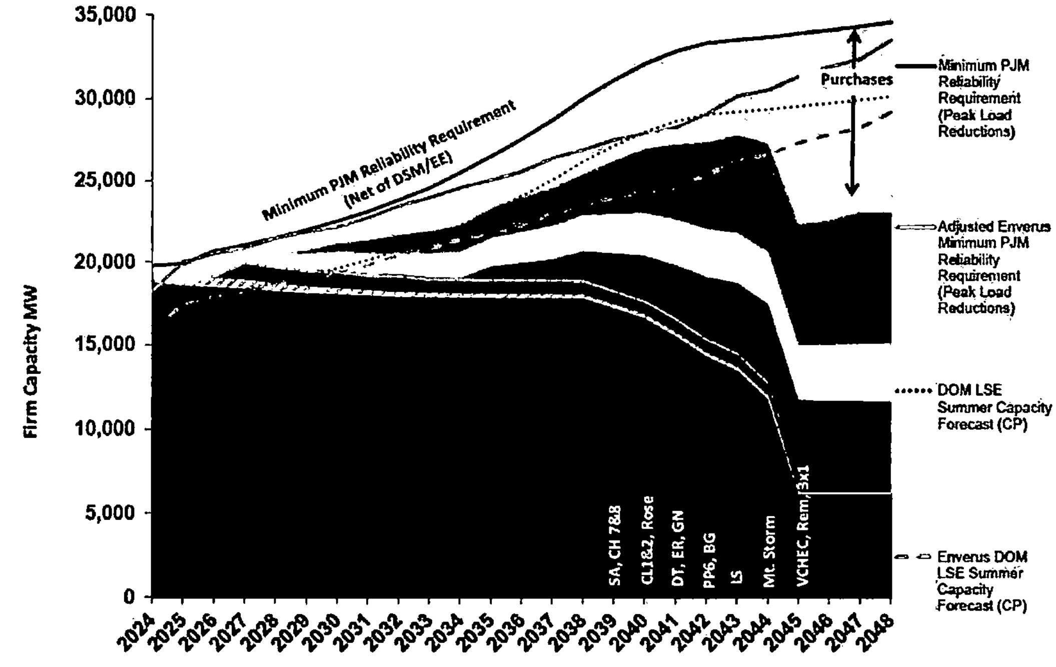
Turing to Alternative Plan E, Mr. Glattfelder provided the following table to show the retirement dates for carbon-emitting units under this plan.[249]

Facility	Retirement Year
Chesterfield 7	2039
Chesterfield 8	2039
South Anna	2039
Clover Unit 1	2040
Clover Unit 2	2040
Rosemary	2040
Darbytown	2041
Elizabeth River	2041
Greensville	2041
Possum Point Unit 6	2042
Bear Garden	2042
Ladysmith	2043
Mt. Storm	2044
VCHEC	2045
Remington	2045

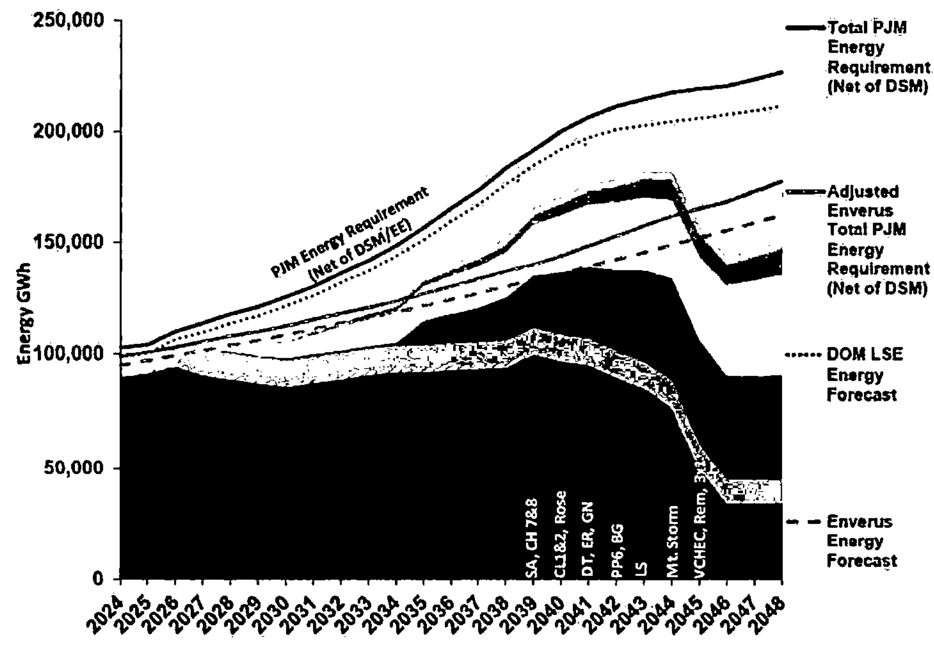
[249] Ex. 40 (Glattfelder) at 23.

Mr. Glattfelder sponsored the following Staff graphs to show the Enverus forecasts overlaying Dominion's Alternative Plan E resource additions.[250]

Alternative Plan E, Enverus Forecast Overlay, Capacity (MW)



Alternative Plan E, Enverus Forecast Overlay, Energy (GWH)



[250] *Id.* at 29-30.

Mr. Glattfelder's testimony identifies the resources associated with the top five shaded areas on his Alternative Plan B tables as resources that are not existing or under construction. These areas depict – from top to bottom – new fossil (light brown); new storage (green); new solar (yellow); new wind (light blue); and new nuclear (dark purple).[251]

Mr. Glattfelder also noted that to the extent future fuel, energy, capacity, and REC prices more closely align with the forecasts of Staff witness Johnson, Staff expects the model outputs and plan costs would also change.[252]

Mr. Glattfelder expressed Staff's opinion that the primary need for the CE-4 Projects is compliance with parts of the VCEA, but that the provision of capacity and energy to Dominion's customers is a secondary driver.[253] He described RECs as "the unique characteristic to these facilities" because energy and capacity can be fulfilled by any generating unit.[254]

Turning to the results of Dominion's economic analysis of the CE-4 Projects under the ICF REC price forecast and statutory deficiency payment, Mr. Glattfelder indicated that Staff did not oppose the capacity factors used by Dominion.[255]

Mr. Glattfelder discussed the four CE-4 Projects for which the Petition seeks CPCNs, including the estimated costs and economic impacts presented by the Company.[256] Staff does not oppose the Commission's approval of these proposed CE-4 Projects, but raised certain concerns.[257]

Mr. Glattfelder's testimony indicates that risks have materialized for the CE-1, CE-2, and CE-3 Projects approved by the Commission. All CE-1 Projects exceeded their budgets on electrical interface, due to increased interconnection costs, and two also exceeded their budgets on construction and equipment costs. Eleven of the 15 CE-2 Projects are over budget on construction and equipment costs. Two CE-2 Projects are over budget, and two are below budget, on electrical interface costs. Four of the eight CE-3 Projects are already over budget on construction and equipment costs.[258]

For future RPS plan filings, Staff recommended that the Commission require Dominion to list what risks were identified for the selected projects.[259] Mr. Glattfelder believes that O&M issues, equipment availability, and operational downtime are reasonable to consider as "risks" to the performance of the CE-4 Projects.[260] He described some of the risk categories included in

---

[251] *Id.* at 19-22.
[252] *Id.* at 30-31.
[253] *Id.* at 32.
[254] Tr. at 254 (Glattfelder).
[255] Ex. 40 (Glattfelder) at 34, rev. 35, 36.
[256] *Id.* at 36-39.
[257] *Id.* at 44. Staff took no position on whether the CE-4 Projects are in the public interest.
[258] *Id.* at 39-40. *See also* Ex. 40-ES (Glattfelder) at Attachment MSG-6. *But see* Tr. at 263 (Glattfelder) (clarifying the far right column).
[259] Ex. 40 (Glattfelder) at 41. As corrected in Dominion's errata filing made November 9, 2023, the 2021 and 2022 capacity factors for Spring Grove were 25.30% and 20.90%, respectively. Ex. 4 (2023 RPS Development Plan) at Attachment 4 (rev. Nov. 9, 2023).
[260] Ex. 40 (Glattfelder) at 43.

selection documentation provided by Dominion as comprehensive, but he found no indication of which categories Dominion considers a risk for selected projects.[261]

Mr. Glattfelder identified Staff concerns that suboptimal solar output or maintenance of the Company's solar fleet can lower capacity factors. He described the capacity factors for Morgan's Corner, Whitehouse, Woodland, and Spring Grove solar facilities as "noticeably lower" in 2022 compared to prior years.[262] He attached to his testimony a Company response to Staff discovery that stated in part:

> Whitehouse Solar experienced lower production in 2022 due to higher than expected availability losses caused by multiple failures of the inverter unit capacitor banks. In 2022, Woodland Solar experienced lower production due to a high amount of required maintenance outages on the distribution line feeding the site. Spring Grove 1 Solar experienced lower production in 2022 due to inverter outages and less than expected insolation.[263]

The Company discovery responses attached to Mr. Glattfelder's testimony also indicate that visual inspection of solar trackers is performed on a periodic basis, with measures taken to resolve any identified issues in a timely manner. The attached responses further indicate, among other things, that Spring Grove is one of the US-3 facilities, which are subject to a performance guarantee.[264]

Mr. Glattfelder testified that lower capacity factors can cause Dominion's modeling to select more resources or energy and/or REC purchases than would be necessary with higher capacity factors. He recognized that if Dominion's fleet does not generate the expected benefits that customers pay for, customers may have to pay for additional RECs to meet the statutory RPS requirements.[265]

Mr. Glattfelder recommended that, for Dominion's solar fleet, the Company be required to include in future RPS plan filings a schedule, per facility, that identifies both planned and unplanned outages during the previous calendar year, including the actual stop/start dates and times, the corresponding MW of nameplate capacity affected by the outage, corresponding energy sales lost in MWh as a result of the outage, and a brief description of the cause of each outage.[266] He explained that Dominion provided similar information in the pending Rider US-3 proceeding, Case No. PUR-2023-00137. He indicated that for lost sales data, a directive for the Company to provide such information during discovery (if requested) would be sufficient.[267]

---

[261] Tr. at 252 (Glattfelder).
[262] Ex. 40 (Glattfelder) at 41.
[263] *Id.* at 42 and Attachment MSG-1 (Dominion's response to Staff discovery request no. 1-61). The referenced discovery request did not identify Morgan's Corner.
[264] *Id.* at Attachment MSG-1 (Dominion's response to Staff discovery request no. 1-61(a) through (r), (t), (u), and (v)).
[265] *Id.* at 43.
[266] *Id.* at 44. As recommended, this information would be provided for facilities paid for by Virginia jurisdictional ratepayers as well as ring-fenced facilities. Tr. at 250-51 (Glattfelder).
[267] Tr. at 249-50 (Glattfelder).

Mr. Glattfelder described the Company's economic cost-benefit analysis of the CE-4 Projects and Distributed Solar Project, including the three scenarios for REC pricing and assumed capacity factors.[268] He reproduced net present value results tables provided in Dominion witness Morton's testimony, except Mr. Glattfelder used the three-year average capacity factor results that Mr. Morton provided in footnotes for Blue Ridge and Alberta.[269]

Mr. Glattfelder characterized the Petition's Scenario 1 (avoided deficiency payment for all REC pricing) and Scenario 2 (forecasted REC pricing for all RECs) as brackets that essentially provide the outer limits of possible outcomes, given Dominion's analysis.[270] He described Scenario 3 (avoided deficiency payment for 70% of RECs and forecasted REC pricing for 30%) as a possible outcome.[271]

Mr. Glattfelder recognized that – when the social cost of carbon is incorporated in the results – the net present value results for the entire CE-4 Projects and Distributed Solar Project portfolio are positive for Scenarios 1 and 3, but not Scenario 2.[272] His tables show that only Bookers Mill in Scenario 1 has a positive net present value when the social cost of carbon is not incorporated.[273] His tables also show Dominion's results for Blue Ridge, Alberta, and Peppertown are negative across all three scenarios, even when the social cost of carbon benefit is added to the modeling results and the REC values.[274]

As for whether Staff recommends an appropriate scenario for the Commission's consideration, given the substantial uncertainty regarding the continued development of the Virginia REC market, Mr. Glattfelder recommended that the Commission require Dominion to continue modeling at least three scenarios similar to those presented by the Petition.[275]

Mr. Glattfelder provided the following levelized costs of energy for the CE-4 Projects and Distributed Solar Project.[276]

	Blue Ridge	Beldale	Michaux	Bookers Mill	Alberta	Peppertown
Levelized Costs of Energy Excluding RECs ($/MWh)	$119.7	$119.1	$113.2	$89.0	$167.8	$165.9

He indicated that these figures differ from the Company's calculations because Staff reflected dollar values associated with the commercial operation date of each facility, while Dominion normalized its calculations to a common year.[277]

[268] Ex. 40 (Glattfelder) at 44-53.
[269] *Id.* at 47-51.
[270] *Id.* at 50.
[271] *Id.* at 52.
[272] *Id.*
[273] *Id.* at 48-49, 51-52.
[274] *Id.* at 48-49, 51; Tr. at 260 (Glattfelder). However, Dominion's results show that adding the social cost of carbon benefit to the modeling results and assumed REC value makes Blue Ridge's results positive in Scenario 1 if the design capacity factor is modeled. *See* Ex. 20 (Morton direct) at attached Sched. 1.
[275] Ex. 40 (Glattfelder) at 53.
[276] *Id.* at 55.
[277] Tr. at 261-62 (Glattfelder).

Ms. Ricketts identified the CE-1, CE-2, and CE-3 PPAs that have been terminated; presented an economic analysis of the CE-4 PPAs and Distributed Solar PPAs; and discussed environmental justice in relation to the CE-4 Projects, Distributed Solar Project, PPAs, and Distributed Solar PPAs.

Ms. Ricketts reported that six of the sixteen CE-2 Distributed Solar PPAs have been terminated because the project developers were unable to obtain conditional use permits and because of inflationary cost effects.[278] Dominion includes these projects in the Company's statutory development target counts because the Company petitioned for their approval, but has not included any costs of the terminated PPAs in the proposed Rider CE.[279]

Ms. Ricketts discussed the 2022 PPA RFP results identified by Company witness Keefer.[280] Ms. Ricketts pointed out that the 240 MW nominal capacity for the Sycamore Cross CE-4 PPA identified in the Petition differs from the 203 MW nominal design capacity identified in a pending CPCN proceeding for the underlying generation facility.[281] Staff recognized that several factors – such as site topography, construction, and permitting – make it difficult to specify the exact capacity of a future solar facility. Ms. Ricketts observed that the final capacity for four of five projects for which Dominion identified had an allowed capacity range ended up at or towards the lower end of the range.[282] Staff recommended that, where available, the Commission require Dominion to report both the low-end and high-end of the range of potential capacities for future PPAs for solar facilities that have not yet completed construction.[283]

Ms. Ricketts expressed Staff's opinion that the primary need for the CE-4 PPAs is compliance with parts of the VCEA, but that the provision of capacity and energy to Dominion's customers is a secondary need.[284]

Ms. Ricketts described the economic analysis,[285] including the Company's social cost of carbon calculation, conducted for the CE-4 PPAs and Distributed Solar PPAs.[286] She agreed with Dominion's decision to model the Highlands PPA only at its design capacity factor.[287] After reporting that Dominion objected to providing disaggregated results for four CE-4

[278] Ex. 41 (Ricketts) at 3-4 (identifying the termination dates for Rockingham Scenic Farms, Knollwood, Nuby Run, Sandale, USS Boykins 1, and USS Boykins 3).

[279] *Id.* at 4 and Appendix AR-1, p. 4.

[280] *Id.* at 5. Ms. Ricketts indicated that Dominion's RFP process introduced to the non-price scoring guideline a new environmental category intended to assess a project's potential impacts on forests, ecological cores, and prime farmland, as well as site plan characteristics such as plans to minimize habitat fragmentation. *Id.* Dominion clarified that this information is applicable to the Development RFP, not the 2022 PPA RFP. Ex. 47 (Keefer rebuttal) at 4.

[281] Ex. 41 (Ricketts) at 6-7 (citing Case No. PUR-2023-00136).

[282] Ex. 41 (Ricketts) at 7 and Appendix AR-1, p. 17.

[283] *Id.* at 7.

[284] *Id.* at 9.

[285] Ms. Ricketts found some of Dominion's net present value results counterintuitive. Ex. 41 (Ricketts) at 16-17. However, she indicated that the Company's rebuttal testimony addressed Staff's concern on this issue. Tr. at 277 (Ricketts).

[286] Ex. 41 (Ricketts) at 10-23.

[287] *Id.* at 13-14, 19, 21. Ms. Ricketts identified Highlands as the only CE-4 PPA or Distributed Solar PPA with a design capacity factor lower than the Company's three-year historical average capacity factor. *See, e.g., id.* at 13-14.

Distributed Solar PPAs, Ms. Ricketts recommended that Dominion be required in future RPS plan cases to provide the net present value analysis of each proposed Company-owned or PPA generating facility on an individual basis (not grouped).[288] She indicated that separate net present values may provide a clearer picture of the magnitude and direction that such values of a particular project may have on the overall results and would make it easier to review and determine the merits of each specific project.[289]

Similar to Staff witness Glattfelder, Ms. Ricketts indicated that Scenarios 1 and 2 can be viewed as a bracket with the former representing a maximum value and Scenario 2 representing the minimum.[290] She indicated that Scenario 3 may be an appropriate point of comparison that more closely aligns with what could occur.[291] Similar to Mr. Glattfelder's recommendation regarding the economic analysis of Company-owned proposals, Ms. Ricketts recommended that for future PPA proposals the Commission should require Dominion to continue modeling at least three scenarios similar to those presented by Company witness Morton in this case.[292]

Ms. Ricketts provided levelized cost of energy information that Dominion produced in discovery for the CE-4 PPAs and Distributed Solar PPAs. Staff did not take a position on the reasonableness of these levelized costs of energy.[293]

Ms. Ricketts identified the Company's non-price PPA evaluation scores provided with the Petition, which she reproduced with formatting by Staff. She highlighted that **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][294] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

Ms. Ricketts addressed the economic development benefits claimed by Dominion for the CE-4 PPAs and Distributed Solar PPAs. She summarized the estimates from Mangum Economics, LLC ("Mangum"), for the proposed PPAs.[295] Based on Mangum reports and their disclaimers, Staff believes that, although each CE-4 PPA project will likely provide some regional economic and fiscal benefits, Mangum's estimates are uncertain and should be treated as forecasts, rather than guaranteed levels, of economic benefits.[296]

---

[288] *Id.* at 15-16 and Appendix AR-1, p. 29.
[289] Tr. at 271 (Ricketts).
[290] Ex. 41 (Ricketts) at 19.
[291] *Id.* at 22.
[292] *Id.*
[293] *Id.* at 24-25.
[294] Ex. 41, 41-ES (Ricketts) at 25 and Appendix AR-2, pp. 5-6.
[295] Ex. 41 (Ricketts) at 26.
[296] *Id.* at 27. Ms. Ricketts attached to her testimony the report Mangum prepared for the Sycamore Cross PPA. *Id.* at Appendix AR-2, pp. 8-20.

Turning to environmental justice, Ms. Ricketts expressed Staff's appreciation for the Company's attempt to address concerns raised by Staff during the 2022 RPS Plan Case.[297] According to Ms. Ricketts, the Company's analysis indicates that all of the proposed CE-4 Projects and Distributed Solar Project, excluding Peppertown, are located within a census block group that meets at least one of the criteria for designation as an environmental justice community, as described by the VEJ Act.[298] She highlighted that the Michaux solar project and the CE-4 Distributed Solar Project (Alberta) appear to be located in a historically economically disadvantaged community under the VCEA and a "community in which a majority of the population are people of color" under the VCEA. For the Michaux and Blue Ridge solar projects, the proportion of the population of color within the study areas also exceeds the Virginia average, making them environmental justice communities under the VEJ Act. Staff did not take issue with Dominion's environmental justice analysis of the CE-4 Projects and Distributed Solar Project.[299]

Ms. Ricketts recognized the Company's indication that all 13 CE-4 PPA and Distributed Solar PPA facilities are located within one mile of communities that meet at least one criterion for designation as environmental justice communities. Three of these facilities are located within tracts that meet at least one criterion for destination as a historically economically disadvantaged community under the VCEA.[300]

Ms. Ricketts attached to her testimony a discovery response by Dominion that highlights the environmental justice outreach performed by PPA project developers during the RFP bid process.[301] The Company's response also indicates, among other things, as follows:

> The presence of [environmental justice] communities should not exclude an area from clean energy development. While solar projects are not devoid of environmental impacts, they are not expected to cause significant adverse effects or health risks to any surrounding community, including potential [environmental justice] populations. According to a recent study by … DEQ, approximately 53% of the geographic area and 58% of the Commonwealth's population are in geographic areas that meet the definitions for an [environmental justice] community under the [VEJ Act]. Excluding these significant portions of the Commonwealth from clean energy development would not only hamper the Company's ability to meet the development targets under the [VCEA] in a cost effective manner, but it would also deny [environmental justice] communities the opportunity to share in the benefits of clean energy development, including jobs and tax revenues. Therefore, in the Company's view, the pursuit of clean energy promotes environmental justice for the Commonwealth.[302]

---

[297] Ex. 41 (Ricketts) at 29-30. She also noted that Dominion conducted an environmental justice analysis of Bookers Mill, notwithstanding the Company's legal position that the Commission is not required to consider environmental effect or establish conditions to minimize environmental impact for this facility, which previously received a permit by rule from DEQ. *Id.* at 32.

[298] *Id.* at 31 and Appendix AR-2, pp. 2-3.

[299] *Id.* at 31-32.

[300] *Id.* at 33-34.

[301] *Id.* at 34; Ex. 41-ES (Ricketts) at Appendix AR-1, pp. 5-10.

[302] Ex. 41 (Ricketts) at Appendix AR-1, pp. 9-10.

Ms. Ricketts represented that Staff does not take issue with the Company's environmental analysis for the CE-4 PPAs or the proposed siting for any of the underlying facilities.[303]

Ms. Ricketts discussed an independent environmental justice evaluation that Staff conducted using the DEQ Geospatial Data and Tools EJSCREEN+ mapping tool.[304] Based on Staff's evaluation, and contrary to the Company's evaluation, Bookers Mill and one of the CE-4 Distributed PPAs, USS Mt. Sidney, do not appear to be located within one mile of an environmental justice community.[305] She indicated that her analysis using this DEQ tool did not identify any fenceline communities because the DEQ tool does not indicate whether the communities identified as low-income or people of color include fenceline communities.[306]

Should the Commission determine that it would be beneficial for all interested parties to have the opportunity to perform their own environmental justice reviews of proposed Company-owned and PPA projects, Staff recommended that the Commission direct Dominion to include shapefiles for all projects and PPAs in future RPS plan cases.[307]

Ms. Ricketts reviewed the results of the Company's environmental justice analysis for the CE-4 Projects and Distributed Solar Project, which is discussed in Section II of this Report's Analysis below.[308]

Mr. Unger addressed Dominion's 2021 and 2022 Compliance Reports and Company witness Gaskill's supplemental direct testimony. According to Mr. Unger, Dominion's total retail sales for 2021 and 2022 RPS compliance periods were inconsistent with information reported in Form EIA-861 or FERC Form No. 1. Staff supports the Company's use of FERC Form 1 information for purposes of RPS compliance calculations and reporting.[309]

Mr. Unger initially recommended that Dominion report its RPS obligation calculation in a specific format. However, he indicated that it would be sufficient for the annual RPS plan filings to include the data used to determine "total electric energy" and the associated RPS obligation.[310]

Mr. Unger identified a specific line number in FERC Form 1 that Staff believes would be the appropriate MWh volume for "electric energy sold to retail customers in the Commonwealth service territory of a ... Phase II Utility" under Code § 56-585.5 A.[311] He indicated that

[303] *Id.* at 35.
[304] *Id.* at 35-36. For two facilities, Staff used coordinates provided by the Company, in tandem with Google Earth and the ArcGIS-Virginia Parcels (Map Service), because Staff was unable to verify potential communities through the EJSCREEN+ mapping tool. *Id.* at 36.
[305] *Id.* at 36.
[306] Tr. at 273-74 (Ricketts).
[307] Ex. 41 (Ricketts) at 36-37.
[308] *Id.* at 37-41.
[309] Ex. 43 (Unger) at 9-11; Tr. at 328 (Unger).
[310] Tr. at 332-33 (Unger). Staff does believe its recommended report would be necessary in Case No. PUR-2024-00010, the separate RPS compliance case often referred to in the record as the "standalone proceeding." Tr. at 333 (Unger).
[311] Ex. 43 (Unger) at 11.

Dominion has used two different methodologies to report sales from delivery-only customers in FERC Form 1s. He recommended that Dominion add an explanatory footnote and seek clarification from FERC on how to reconcile the two methodologies used in past FERC Form 1s.[312]

Mr. Unger questioned Dominion's inclusion of sales to VMEA in the Company's RPS calculations.[313] He recognized that Dominion provides FERC-jurisdictional wholesale service to VMEA,[314] whose retail customers are outside the distribution service territory of Dominion (and APCo).[315] Mr. Unger also indicated that it may not be appropriate to include Micron in these calculations because "the distribution assets appear to be provided by [t]he City of Manassas."[316]

Mr. Unger suggested that Dominion should have excluded (subtracted) nuclear generation sold to Craig Botetourt.[317] Mr. Unger suggested that the Commission could also exclude (subtract) load served by competitive service providers from the nuclear calculation.[318]

Mr. Unger calculated an updated 8,488,047 MWh "Exempt Customer Load," compared to Dominion's 6,068,477 figure initially identified by Company witness Gaskill.[319] As part of the ARB certification process, Mr. Unger confirmed that ARBs are required to submit a list of RPS-eligible resources under contract, the terms of such contracts, and the underlying contracts.[320]

Mr. Unger found too much uncertainty to support Dominion's RPS compliance calculations and expressed concern that the 2022 Compliance Report's obligation of approximately 9.3 million RECs "may be on the high side." He indicated that any uncertainty that cannot be addressed in the instant proceeding can be addressed in Case No. PUR-2024-00010, the standalone proceeding Dominion initiated on January 16, 2024.[321]

Mr. Unger reported that Dominion inadvertently retired 136,769 RECs with the year 2023, rather than 2022. Additionally, Dominion inadvertently retired 19,615 in-state RECs with the year 2022 that the Company intended to add to its REC bank.[322] He indicated that Dominion needs permission from the Commission for the Administrator of PJM Generation Attribute Tracking System ("GATS") to unretire these RECs. He recommended that Dominion request such permission from the Commission "in order to keep the GATS records accurate and allow[]

---

[312] *Id.* at 11-13.
[313] *Id.* at 13-14; Tr. at 335-36 (Unger).
[314] Ex. 43 (Unger) at 13.
[315] *Id.* at 23.
[316] *Id.* at 15.
[317] *Id.* at 24.
[318] *Id.* at 26-27.
[319] Exs. 43, 43-ES Code of Conduct (Unger) at 28-29.
[320] Tr. at 337-38 (Unger).
[321] Ex. 43 (Unger) at 30.
[322] *Id.* at 31.

market participants to know … the total volume of RECs available and prevent double counting."[323]

It appeared to Mr. Unger that Dominion purchased some types of RECs in 2023 that are excluded by Code § 56-585.5 C and the Commission's GATS Business Rules.[324] The table below shows the type, vintage, and volume of RECs questioned by Mr. Unger, all of which are out-of-state RECs.[325]

Fuel Type	Pre 2021	2021	Post 2021	Total RECs
Solid Waste - Tire Derived	23,747			23,747
Wood - Black Liquor	9,976			9,976
Biomass - Other Biomass Gases	649			649
Captured Methane - Landfill Gas	12,684	27,445	14,182	54,311
Waste Heat	76,611			76,611

It is unclear to Staff whether the underlying out-of-state biomass, landfill gas, and waste heat facilities qualify for RPS compliance without an accompanying affidavit required by the Commission's GATS Business Rules.[326] Mr. Unger indicated that for compliance years 2021 and 2022 solid waste - tire derived RECs were on the non-eligible list from the GATS Business Rules. He further indicated that the Commission may need to determine in the instant case the eligibility of wood - black liquor RECs because this category of RECs was not on either the eligible or non-eligible list from the GATS Business Rules.[327]

Mr. Unger confirmed that the RECs Dominion retired had a Virginia state certification in GATS. However, he indicated that when the RPS market changed from voluntary to mandatory, there was no change in what was allowed within GATS. He indicated that RECs he questioned had Virginia certification numbers associated with the voluntary market.[328]

Mr. Unger indicated that, if approved by the Commission, Staff would support the approach Dominion witness Leimann identified on rebuttal regarding how to deal with legislative changes to RPS resource eligibility. However, he indicated this would be a new approach.[329] Staff would also support Dominion's rebuttal proposal to submit a certification for

---

[323] *Id.* at 32-34. Mr. Unger attached to his testimony portions of PJM's business rules for GATS, along with correspondence between himself and a PJM employee. *Id.* at Attachment No. MBCU – GATS Dispute Resolution Process.

[324] *Id.* at 34-44. As used herein, the Commission's "GATS Business Rules" refers to the business rules that the Commission has approved and revised in Case Nos. PUR-2021-00064 and PUR-2022-00045. *See, e.g., Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: In the matter of registering and retiring Virginia-eligible renewable energy certificates*, Case No. PUR-2021-00064, 2021 S.C.C. Ann. Rep. 458, Order Revising Business Rules (Sep. 30, 2021) ("*2021 Business Rules Order*").

[325] Ex. 43 (Unger) at 35.

[326] *Id.* at 36-38.

[327] *Id.* at 38-39.

[328] Tr. at 340-41 (Unger).

[329] Tr. at 330 (Unger).

biomass and waste heat RECs after the final RPS Program obligation for compliance year 2022 is finalized.[330]

Mr. Unger testified that Staff does not object to Dominion witness Leimann's interpretation that the certification requirement for biomass and waste heat RECs does not require Dominion to review the affidavits that each generator submits to PJM for these RECs. However, he indicated that the Commission has not addressed this matter in light of RECs associated with state certification numbers for biomass and waste heat that are still active from the voluntary market when no affidavit was necessary.[331]

Dominion – Rebuttal Testimony

Dominion filed the rebuttal testimonies of **Messrs. Flowers, Morton,** and **Gaskill; John R. Leimann**, Senior Market Originator for the Company; **Mses. Boschen, Prideaux**, and **Lecky**; and **Kathryn E. MacCormick**, Supervisor of Environmental Justice for Dominion Energy Services, Inc.

Mr. Flowers expressed Dominion's willingness to file the executed Interconnection Service Agreements for the CE-4 Projects to confirm no unaddressed impacts on reliability, consistent with prior cases.[332] The executed agreements for the four projects for which Dominion requests CPCNs were admitted as exhibits in this case.[333]

Mr. Flowers noted that Staff does not oppose approval of the CE-4 Projects and does not state a position on the CE-4 Distributed Solar Project. He added that no respondent witness recommends the Commission deny approval of any of these projects.[334]

In response to Staff witness Glattfelder's recommendation that the Commission require Dominion to list the risks identified for the selected projects, Mr. Flowers indicated that Dominion's Petition already did so. In support of his position, Mr. Flowers cited portions of Filing Schedule 46A, which include materials used by senior management in approving the CE-4 Projects and the non-price evaluation of the CE-4 Projects.[335] Mr. Flowers described Dominion's evaluation of the CE-4 Projects and Distributed Solar Project as comprehensive.[336] However, Mr. Flowers indicated that Dominion would agree to include in a summary table for its next RPS plan petition a listing of the key risks and key risk categories.[337]

---

[330] Tr. at 331 (Unger).
[331] Tr. at 336-37 (Unger).
[332] Ex. 46 (Flowers rebuttal) at 3-4.
[333] Ex. 12.
[334] Ex. 46 (Flowers rebuttal) at 5.
[335] *Id.* at 5.
[336] *Id.* Regarding the budget/cost data for the CE-1, CE-2, and CE-3 Projects and Distributed Solar Projects, Mr. Flowers pointed out that Staff witness Glattfelder's Attachment MSG-6 includes data only for cost categories with variance greater than 5%, rather than the full budget/cost data provided in Filing Schedule 46A. *Id.* at 6.
[337] Tr. at 358 (Flowers).

Mr. Flowers elaborated on changes to the costs of the CE-2 Dulles Solar + Storage project since the Petition was filed. However, he represented that Dominion does not anticipate the total cost will vary from the updated $443.7 million estimate provided in the Petition.[338]

In response to Staff testimony regarding REC price assumptions used in Dominion's net present value analysis, Mr. Flowers believes there are a number of factors – and not just the potential revenue stream for RECs – affecting solar development in Virginia.[339]

Mr. Flowers indicated that Dominion does not oppose Staff witness Brunelle's recommendation that Dominion continue to monitor new and developing energy storage technologies and refine its assumptions in future proceedings as appropriate.[340]

In response to Appalachian Voices witness Abbott, Mr. Flowers testified that Dominion agrees there are locational benefits to storage from a generation development perspective.[341] Mr. Flowers confirmed that Dominion considers the location of a storage project, including its proximity to a load center, when evaluating proposals with similar scores. He described such consideration is qualitative, rather than quantitative. He indicated that the generation personnel at Dominion do not have information on transmission constraints due to FERC functional separation rules. However, he acknowledged that PJM does have a database of historic nodal prices that can be studied for price variability. He indicated that such a study could provide a snapshot in time historical view on price volatility and variability, which is an indicator of where there may be constraints on the system.[342]

Mr. Keefer represented that Dominion does not oppose Staff witness Ricketts' recommendation for Dominion to report, in future filings, both the low-end and high-end of the range of potential nameplate capacities for future PPAs for solar facilities that have not yet completed construction.[343] Mr. Keefer also confirmed that Dominion has the information necessary to calculate annual capacity factors for solar PPAs and would not oppose reporting this information, if directed by the Commission.[344]

Mr. Keefer does not necessarily agree with Staff witness Ricketts that Dominion's use of the statutory deficiency payment as a REC value in economic analysis may overstate the CE-4 PPAs' value. He cited the increasing cost of solar development and his belief that solar development may continue to prove difficult. He opined that these challenges cannot necessarily be overcome by REC revenue valued at the statutory deficiency payment alone.[345] Mr. Keefer also stressed the difficulty of projecting future REC prices. However, he acknowledged that the

[338] Tr. at 362 (Flowers); Tr. Day 2 ES Session 1 at 5-12 (Flowers).

[339] Ex. 46 (Flowers rebuttal) at 7 (citing PJM queue delays, land availability, and permitting challenges).

[340] *Id.* at 7.

[341] *Id.* at 7-8. Mr. Flowers also attached to his testimony a complete version of a discovery response for which Mr. Abbott provided a partial version. Ex. 46-C (Flowers rebuttal) at Conf. Sched. 1.

[342] Tr. at 264-67 (Flowers).

[343] Ex. 47 (Keefer rebuttal) at 3.

[344] Tr. at 372 (Keefer).

[345] Ex. 47 (Keefer rebuttal) at 3.

statutory deficiency payment as a REC value represents the outer bound of assumed values for RECs.[346]

Mr. Keefer addressed Appalachian Voices witness Abbott's recommendation that Dominion proactively seek out long-term agreements for unbundled REC purchases by (i) requiring developers in its annual PPA RFP to provide a REC-only price offer in addition to a bundled REC offer, or (ii) approaching developers not selected through a PPA RFP about a REC-only contract. Mr. Keefer testified that Dominion does not believe such action is necessary at this time. He indicated that Dominion's staggered approach to procuring RECs by purchasing bundled products for longer terms, coupled with shorter term REC purchases in the spot market, helps mitigate the risks of REC procurement. He also does not believe REC revenue alone would be sufficient to justify the cost to build new solar resources.[347] He would not rule out the possibility that Dominion could find long-term agreements for unbundled RECs necessary in the future, but the Company does not currently see a need for, or benefit from, such agreements.[348]

Mr. Keefer acknowledged that a conforming bid for a PPA from Peppertown – one of the proposed CE-4 Projects – was submitted in the Company's 2021 RFP. He confirmed that Peppertown's bid was not selected based on its offer price.[349]

Mr. Morton agreed that Dominion did not want to re-litigate issues from the 2023 IRP Case and further agreed with Appalachian Voices and Staff that any directives related to long-term system modeling in the 2023 IRP Case should be reflected in any long-term system modeling incorporated into future RPS development plans.[350] Mr. Morton added that such incorporation should become more straightforward because Dominion expects to file its 2024 IRP around the same time as its 2024 RPS development plan.[351]

Mr. Morton disputed Staff witness Glattfelder's characterization of energy and capacity needs as secondary to VCEA compliance. Mr. Morton cited Dominion's projections that its capacity and energy needs will grow, even under modeling assumptions: (i) of normal weather; and (ii) that no existing generation units are retired. Due to Dominion's responsibility for system reliability, Mr. Morton does not recommend overreliance on market purchases, for which there are limits on the amount Dominion can purchase and physically receive. He added that other States' retirement of dispatchable generation and addition of renewable generation may decrease the amount of capacity and energy available for purchase – especially during the winter.[352]

Mr. Morton similarly pushed back on Appalachian Voices witness Abbott's assertion that there is "no pressing need" for the CE-4 Projects, Distributed Solar Project, and PPAs. Mr. Morton indicated, among other things, that Dominion's capacity, energy, and REC forecasts incorporate the load forecast published by PJM, as directed by the Commission.[353]

[346] Tr. at 379-80 (Keefer).
[347] Ex. 47 (Keefer rebuttal) at 4.
[348] Tr. at 376 (Keefer).
[349] Tr. at 381-82 (Keefer). *See also* Ex. 48-ES.
[350] Ex. 49 (Morton rebuttal) at 2-3.
[351] *Id.* at 14.
[352] *Id.* at 4-5.
[353] *Id.* at 5.

According to Mr. Morton, Dominion is amenable to continuing to present three scenarios for REC benefits in future cases that are generally consistent with the scenarios presented in the instant case. He indicated that the blended REC scenario would be modified to the extent Dominion adjusts its long-term planning assumptions regarding the availability of RECs.[354] He does not believe any additional modeling sensitivities need to be run to deem the proposed CE-4 Projects, Distributed Solar Project, and PPAs reasonable and prudent.[355]

Mr. Morton explained the conceptual and practical problems associated with using a three-year historical average capacity factor in the economic analysis of projects with design capacity factors that are lower than the historical average.[356]

Mr. Morton confirmed that the federal government's per-ton social cost of carbon estimate used to calculate his estimated net present values of the social cost of carbon benefit in his economic analysis is a global social cost of carbon estimate, representing global impact. He is not aware of any social cost of carbon estimates specific to a region.[357]

In Mr. Morton's view, Dominion's approach of aggregating the economic analysis results of the CE-4 Distributed Solar PPAs using tracking technology is reasonable and is consistent with the results presented in prior cases. He explained that Dominion expects the results for the individual PPAs to be directionally similar based on the number of distributed solar PPAs and the similarity in their size.[358]

Mr. Morton testified that Appalachian Voices witness Abbott is incorrect that potential fuel savings from the CE-4 Projects, Distributed Solar Project, and PPAs depend on the marginal unit being Company-owned. According to Mr. Morton, if a Company-owned unit is not reduced, the relevant energy is available to either reduce energy purchases from PJM or increase the amount of energy sold to PJM, either of which benefits customers. He indicated that under the approved cost recovery framework, and assuming Rider CE and Rider PPA are consolidated, these benefits will flow through Rider CE.[359]

Mr. Morton also disagreed with Appalachian Voices witness Abbott's testimony regarding Dominion's coal-fired units. Mr. Morton testified that the energy from CE-4 Projects and PPAs will improve Dominion's net purchase position, regardless of whether Dominion's coal units are designated as must-run. He also testified that Mr. Abbott's testimony is unsupported and ignores the reliability concerns of early retirement.[360]

---

[354] *Id.* at 6.
[355] *Id.* at 6-7.
[356] *Id.* at 7-8.
[357] Tr. at 386-87 (Morton).
[358] Ex. 49 (Morton rebuttal) at 9.
[359] *Id.* at 11.
[360] *Id.*

Mr. Morton downplayed the levelized cost of energy as a high-level metric and he stressed the importance of "compar[ing] like for like when looking at" this metric.[361] He provided the Company's levelized cost of energy calculations with the following tables.[362]

Project Name	Type	Solar MW	RECs 35 Yr $/MWh	No RECs 35 Yr $/MWh
Beldale	Utility-Scale Solar	57.00	$ 85.21	$ 93.47
Blue Ridge	Utility-Scale Solar	95.00	$ 85.70	$ 93.95
Bookers Mill	Utility-Scale Solar	127.00	$ 66.91	$ 78.86
Michaux	Utility-Scale Solar	50.00	$ 80.54	$ 88.80
Peppertown	Utility-Scale Solar	5.00	$ 134.99	$ 146.94
Alberta	Distributed Solar	3.00	$ 136.71	$ 148.65

Notes: (1) Assumes design capacity factor for all solar projects. (2) All values in 2023 dollars.

[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]

[redacted]

[END EXTRAORDINARILY SENSITIVE INFORMATION]

According to Mr. Morton, Dominion believes that the above results including the avoided cost of RECs benefit (*i.e.*, those shown under the columns entitled "RECs") provide a more accurate representation for these projects and PPAs.[363]

[361] *Id.* at 12.
[362] Exs. 49, 49-ES (Morton rebuttal) at 13.
[363] Ex. 49 (Morton rebuttal) at 12.

Mr. Morton addressed testimony by Appalachian Voices witness Abbott concerning Dominion's capacity price forecast and locational modeling for energy storage.[364] Mr. Morton testified that adding a locational element to Dominion's long-term modeling would extend the 3-12 hours it currently takes for each modeling run to days. He testified that models that take days instead of hours to run would extend the Company's modeling process from six weeks to months. He indicated that a process this long would make the modeling inputs stale by the time the process is finished and is not an option from the standpoint of putting together timely, informative cases.[365]

Mr. Morton explained that the extent of the difference in the levelized cost of energy for Blue Ridge compared to Peppertown is their capacity factors. He confirmed that Peppertown was modeled with a capacity factor of 18.8% compared to 24.2% for Blue Ridge.[366]

After Dominion disclosed in public session that Peppertown was previously offered to the Company as a PPA,[367] Mr. Morton was asked about a modeling run the Hearing Examiner directed the Company to provide on the Peppertown PPA at its most recent bid price. Mr. Morton indicated that the main difference in the results was caused by the different durations (*i.e.*, 20 years for a PPA and 35 years for a Company-owned resource).[368]

Mr. Morton opposed filing Dominion's IRPs in future RPS plan proceedings. However, Dominion does not oppose posting its IRP and the Excel files for the associated appendices in the electronic discovery site for the matter for ease of reference at the time of filing.[369]

Ms. Prideaux disagreed with Staff witness Glattfelder's suggestion that Dominion apparently has solar operational and performance issues. She indicated that while Dominion takes a comprehensive approach to ensure its solar facilities are operating effectively, year-to-year variation in a facility's capacity factor is expected. She pointed out that the performance of solar facilities depends largely on irradiance and some years will be wetter or sunnier than other years.[370]

While Ms. Prideaux agreed with public witness Tucker that Dominion's solar facilities are unmanned, she testified that the Company has remote view and operation of these facilities that allows for problems to be identified remotely. She indicated that in addition to inspections stemming from remote data, the Company has regularly scheduled visits to inspect facilities that occur on a weekly, monthly, or annual basis.[371]

[364] *Id.* at 14-15.
[365] Tr. at 393 (Morton).
[366] Tr. at 407-08 (Morton).
[367] Tr. at 352-53 (Flowers).
[368] Tr. at 407 (Morton). According to Mr. Morton, Dominion modeled Peppertown as a PPA with a slightly different capacity, but that capacity difference did not "mov[e] the needle." *Id.*
[369] Ex. 49 (Morton rebuttal) at 16. Mr. Morton added the caveat that this assumes the IRP continues to be filed before, or at the same time as, the RPS plan filing. Tr. at 400 (Morton).
[370] Ex. 51 (Prideaux rebuttal) at 1-2. *See also* Tr. at 438 (Prideaux).
[371] Tr. at 432-35 (Prideaux).

Ms. Prideaux testified that Dominion performs regular inspections and maintenance on its solar facilities that are in line with original equipment manufacturer recommendations and best industry practices. She indicated that periodic site inspections are performed to ensure the site is being maintained and operated to Company standards. Inspections are performed on equipment such as combiners, panels, and connectors. Weekly visual inspections are conducted on inverter skids, perimeter fence, array, vegetation, erosion, and drainage issues. Additionally, corrective maintenance is performed as needed to identify and address issues as they arise.[372]

Ms. Prideaux identified initiatives that Dominion has implemented to enhance preventative maintenance. First, Dominion created the spare parts program to mitigate long lead times for parts and components needed for equipment repair and maintenance. Second, Dominion designed the infrared scanning program to detect faulty or underperforming modules and strings during operation by efficiently inspecting hundreds of thousands of pieces of equipment without interfering with day-to-day operations. Third, as discussed in the 2022 RPS Plan Case, Dominion is transitioning from third-party contractor O&M to an in-house solar operations management team for remote operations and electrical maintenance activities.[373]

Ms. Prideaux acknowledged that Dominion's Morgan's Corner, Whitehouse, Woodland, and Spring Grove solar facilities had lower capacity factors in 2022 compared to prior years. However, she indicated that these lower capacity factors generally were not unexpected because capacity factors fluctuate from year-to-year. Ms. Prideaux does not believe the 2022 results for these facilities are indicative of a trend and she believes the initiatives she discussed will enhance the performance of these facilities.[374]

Ms. Prideaux testified that Dominion does not oppose providing certain O&M information for its system solar units similar to the information it provides for the Company's nuclear and fossil units in the annual fuel factor proceeding – namely, a schedule showing the planned and unplanned solar unit outages during the previous calendar year, including the start and stop times of the outages, and the reasons for the outages. However, Dominion does oppose reporting the nameplate capacity (MW) affected by solar outages and corresponding energy sales lost (MWh) as result of outages. She indicated such information would be burdensome to prepare and is beyond what Dominion reports for other types of units. Dominion also opposed reporting such information for ring-fenced solar facilities, which she believes would be irrelevant to RPS plan proceedings.[375] She does not agree that the fact that Dominion has provided MW affected by outages in Rider US-3 proceedings, for solar facilities that are subject to performance guarantees, supports compiling and providing that information for all of Dominion's solar. She described the provision of such information across the entire fleet as unnecessary and burdensome, and believes reporting such information for Dominion's ring-fence facilities is similarly unnecessary.[376] Ms. Prideaux acknowledged that Dominion tracks all outages – full and partial – across its solar fleet. However, she indicated that her team does not calculate

---

[372] Ex. 51 (Prideaux rebuttal) at 2.
[373] *Id.* at 3-4. *See also* Tr. at 422-30 (Prideaux) (describing in greater detail the spare parts program and the infrared scanning program); Ex. 52.
[374] Ex. 51 (Prideaux rebuttal) at 4; Tr. at 417-18 (Prideaux).
[375] Ex. 51 (Prideaux rebuttal) at 5.
[376] Tr. at 415-16 (Prideaux).

energy sales lost for units without a performance guarantee.[377] She believes that capacity factor information, along with the outage information Dominion has agreed to provide, would provide transparency for ratepayers.[378]

Ms. Prideaux confirmed that Dominion monitors annual irradiance received for each of its solar facilities.[379]

Ms. MacCormick responded to Staff's environmental justice analysis. She indicated that the VEJ Act "does not offer any specific guidance on how an [environmental justice] analysis should be conducted, nor have any agencies of the Commonwealth pursued any regulations, rulemakings, or finalized guidance for electric utilities on the topic since the law was passed."[380]

While Dominion does not dispute the potential presence of environmental justice populations near the CE-4 Projects and Distributed Solar Project, Ms. MacCormick expressed Dominion's opinion that it has provided sufficient information to conclude that these facilities would not cause significant adverse and disproportionate impact to any community, including environmental justice communities or historically economically disadvantaged communities.[381]

Ms. MacCormick explained the various steps the Company takes in its environmental justice review. She indicated that a preliminary screening uses a one-mile radius for projects based on the largest extent that the Company can expect impacts from those particular projects.[382] In the instant case, Dominion's preliminary screening indicated no expected significant health-related impact, so no additional analysis was needed.[383] She testified that Dominion will look out further than one mile if there is a reason, and keeps the data for three miles and five miles in case the Company needs it.[384]

Ms. MacCormick indicated that Staff's use of the outdated data available on the VA EJSCREEN+ website may explain why Staff witness Ricketts found different results from Dominion when Staff conducted its evaluation of environmental justice.[385] While the VA EJSCREEN+ website identifies "2011-2018 ACS" and "2014-2018 ACS" datasets, Dominion used 2017-2021 ACS data taken directly from the U.S. Census website as well as ESRI demographics data. Ms. MacCormick added that the boundaries of census tracts and block groups may be inaccurate using 2018 survey data since census tracts and block groups were updated prior to the 2020 U.S. Census.[386] Ms. McCormick pointed out that Dominion's review and determination resulted in a more inclusive (conservative) approach in this proceeding.[387]

---

[377] Tr. at 420 (Prideaux).
[378] Tr. at 431-32 (Prideaux).
[379] Tr. at 421-22 (Prideaux).
[380] Ex. 51 (Prideaux rebuttal) at 3.
[381] Ex. 53 (MacCormick rebuttal) at 4.
[382] Tr. at 441-42 (MacCormick); Ex. 4 (2023 RPS Development Plan) at Attachment 13.
[383] Tr. at 444 (MacCormick).
[384] Tr. at 448-49 (MacCormick).
[385] Ex. 53 (MacCormick rebuttal) at 2.
[386] *Id.* at 3. ACS stands for the U.S. Census Bureau's "American Community Survey."
[387] *Id.* at 3-4.

Ms. MacCormick was pressed on the applicability of the VEJ Act and about the Company's response to a discovery request in which she indicated that Dominion does not believe the VEJ Act "places a requirement on the Company to ensure that environmental justice is carried out throughout the Commonwealth."[388] She stated, among other things, as follows:

> I don't think anyone would say it's the responsibility of Dominion to ensure environmental justice is carried out throughout the Commonwealth. That can't possibly be completely our responsibility, right? Wouldn't there be other individuals and agencies involved in that?[389]

Ms. Lecky agreed with Staff witness Otwell's revenue requirement calculation. Ms. Lecky indicated that the incremental impact on the monthly bill of a typical (1,000 kWh) residential customer using Staff's revenue requirement would be a $1.51 increase, rather than the $1.54 increase that would result from the Petition's revenue requirement.[390]

Ms. Lecky disputed Appalachian Voices witness Abbott's concerns about Dominion's proposed consolidation of Riders CE and PPA. Contrary to Mr. Abbott's suggestion that such consolidation would camouflage the underlying costs, Ms. Lecky indicated that the costs and benefits of PPAs would continue to be transparent. She testified that Dominion intends to calculate the revenue requirement for a consolidated Rider CE by categories, including a category for all approved PPAs.[391]

Ms. Lecky indicated that consolidating the Rider PPA and CE hearings, but not the rates, would not reduce the number of customer rates. She added that consolidating with a directive for Dominion to continue to break out the PPA information on customer bills would defeat the purpose of rate design consolidation.[392]

Ms. Lecky reiterated Dominion's position that consolidation of Riders CE and PPA is in the interest of judicial economy because the Commission already considers the prudence of PPAs in RPS plan proceedings, and consolidation would allow the Commission to consider associated cost recovery issues in the same case. She believes consolidation is also in the interest of judicial economy and customer transparency because all new solar and storage resources that Dominion is developing pursuant to the VCEA – whether Company-owned or PPA – would be recovered through the same rate adjustment clause. She added that reducing the number of rate adjustment clauses and associated rate changes is beneficial to many stakeholders – including the Commission, Dominion, and customers.[393] She also recognized that cost savings can result from Dominion having one less public notice.[394]

Ms. Lecky acknowledged that the proposed revenue requirement includes financing costs on payments for Peppertown and Alberta that the Company had not actually incurred by the time

[388] Tr. at 459-62 (MacCormick); Ex. 56.
[389] Tr. at 462 (MacCormick).
[390] Ex. 57 (Lecky rebuttal) at 2.
[391] *Id.* at 3 (pointing to Schedule 1 of her direct testimony as an example of this approach).
[392] Tr. at 481-83 (Lecky).
[393] Ex. 57 (Lecky rebuttal) at 4.
[394] Tr. at 480 (Lecky).

of the hearing. However, she characterized the revenue requirement impact of this timing difference as minimal, and subject to correction in the true-up.[395]

Ms. Lecky explained Dominion's waiver request, specifying the information Dominion would no longer provide if the request is granted. She likened Dominion's proposed approach to the manner in which Rider U revenue requirement information is provided.[396]

Mr. Gaskill addressed Staff witness Unger's testimony regarding RPS requirement calculations. Dominion requested that the Commission defer making a finding on the Company's compliance with the RPS Program for compliance year 2022 until sufficient information is available to do so. He indicated such a determination could occur in the standalone proceeding, Case No. PUR-2024-00010, or in a future RPS plan proceeding. Mr. Gaskill stood by the Company's methodology for calculating RPS compliance, and indicated that some line items in Staff witness Unger's proposed reporting format do not seem applicable. However, Mr. Gaskill committed to working with Staff to provide the appropriate level of detail in future proceedings, either in Dominion's compliance filing or discovery.[397] Mr. Gaskill also identified the RPS requirement and compliance issues that Dominion believes would be properly addressed in the instant case, and those the Company believes should be addressed in Case No. PUR-2024-00010.[398]

Mr. Gaskill provided some background on the Company's FERC Form 1 data. He explained that competitive service provider sales are not required to be included in FERC Form 1 data, to his knowledge have never been reported in Dominion's FERC Form 1, and are presumably reported individually by suppliers in each of their FERC Form 1 filings. He opposed transforming this RPS plan proceeding into an audit of the Company's FERC Form 1 and does not agree that the RPS Program compliance calculation should drive FERC Form 1 reporting. Dominion's methodology adds competitive service provider sales data to FERC Form 1 data since such retail sales must be included in the RPS calculation of "total electric energy" pursuant to Code § 56-585.5.[399]

Mr. Gaskill also disagreed with Staff witness Unger's suggestion that VMEA and Micron sales should be excluded from the RPS calculation. Because VMEA and Micron are non-jurisdictional customers, Mr. Gaskill opined that "the relevant question is whether the Company and the respective counterparties agree that the Company is required to meet the Virginia RPS Program requirements on their behalf – which they do."[400] He asserted that the "transmission and distribution system serving customers is not relevant" to RPS compliance calculations because, in his opinion, "the definition of retail sales in this context is a generation-related calculation."[401] He further asserted that Dominion is required by the VCEA and/or contract to include Micron and VMEA in the calculation of "total electric energy," and for those non-

[395] Tr. at 469-70 (Lecky).
[396] Tr. at 471-76, 487-92 (Lecky).
[397] Ex. 58 (Gaskill rebuttal) at 2.
[398] Ex. 60; Tr. at 508-13 (Gaskill).
[399] Ex. 58 (Gaskill rebuttal) at 3.
[400] *Id.* at 4.
[401] *Id.*

jurisdictional customers to continue to pay their share of compliance.[402]

Applying his interpretation to Micron, Mr. Gaskill concluded that "there is no question [its] retail generation needs are served by the Company's generation service and so [Micron's] retail sales should be included in the calculation of total electric energy."[403] Mr. Gaskill acknowledged that Micron is not located within Dominion's distribution service territory.[404] As for VMEA, he indicated that although Dominion does not directly serve VMEA as a retail customer, it is contractually clear that Dominion, "with respect to RPS Program compliance, has an obligation to serve VMEA's retail load in a manner that meets similar requirements as the Company's jurisdictional retail customers."[405]

Mr. Gaskill added that jurisdictional customers would pay essentially the same rate for RPS program compliance, regardless of whether VMEA and Micron are included in the RPS calculation of "total electric energy." He indicated that if these customers were removed, their sales would be removed from both the numerator and denominator of the rate calculation because these non-jurisdictional customers are included in the allocation of the compliance cost.[406]

If the Commission were to decide that sales to VMEA and Micron do not fall within the definition of "total electric energy" pursuant to Code § 56-585.5, Mr. Gaskill indicated that this might not be problematic so long as the decision does not impede the Company's contracts or create questions about the responsibility for paying RPS compliance costs.[407]

Mr. Gaskill testified that Dominion did not include in the calculation of "total electric energy" any sales Dominion made to cooperative wholesale customers. He indicated that some of these customers are located in North Carolina, which are not part of RPS Program compliance, and Virginia cooperatives (including Craig Botetourt) are exempt from the requirements of the RPS Program. He confirmed that Dominion does not comply with the RPS Program on behalf of Craig Botetourt.[408]

For the calculation of an "amount equivalent to the annual percentages of the electric energy that was supplied to [retail customers in the Company's Virginia service territory] from nuclear generating plants located within the Commonwealth in the previous calendar year" pursuant to Code § 56-585.5, Mr. Gaskill does not believe that presenting multiple ratios (as recommended by Staff witness Unger) is necessary and would instead overcomplicate the issues.[409] Mr. Gaskill showed Dominion's calculation of the nuclear percentages that is consistent with the inclusion or exclusion of non-jurisdictional customers from the Company's "total energy sales" calculations. While Dominion stands by its nuclear output calculations,

[402] *Id.* at 5; Tr. Day Two ES Session 2 at 7-9 (Gaskill).
[403] Ex. 58 (Gaskill rebuttal) at 4.
[404] Tr. at 528-29 (Gaskill).
[405] Tr. at 529-30 (Gaskill); Ex. 58 (Gaskill rebuttal) at 4-5.
[406] Ex. 58 (Gaskill rebuttal) at 5.
[407] Tr. at 531-33 (Gaskill).
[408] Ex. 58 (Gaskill rebuttal) at 6.
[409] *Id.* at 6-7.

Mr. Gaskill requested guidance in the instant case, if the Commission determines an alternative method is preferable.[410]

Mr. Gaskill agreed with Staff witness Unger that qualifying ARB sales should be updated for the 2022 RPS compliance year. Dominion intends to update to the final ARB sales value at the conclusion of the standalone proceeding, along with any other compliance updates resulting from that proceeding.[411] Dominion provided its RPS compliance calculation for compliance year 2022 using Staff's update ARB figure. These updated figures make no adjustment for RECs retired by competitive service providers, an issue in Case No. PUR-2024-00010, and are presented both including and excluding competitive service provider sales from the nuclear offset calculation.[412]

Mr. Gaskill agreed with Appalachian Voices witness Abbott that solar resources under contract with ARBs offset the statutory development targets, but Mr. Gaskill cautioned that the Commission has not yet determined the appropriate methodology. Mr. Gaskill identified potential issues he saw with Mr. Abbott's approach for offsetting the statutory interim targets. First, Mr. Gaskill noted that ARB projects might offset interim targets but then not be used for certification in subsequent years. He explained a scenario in which ARBs could choose to decertify based on discussions he has had with two of the four customers that are currently ARBs. He believes legal questions might also need to be answered about the ability for ARBs to certify bundled contracts anywhere in PJM, given the development targets relate to new resources in the Commonwealth and the in-state REC requirements of Code § 56-585.5 C. However, he does not believe such issues need to be resolved in the instant case since the Company's first interim target for solar development is in 2024.[413]

Mr. Gaskill does not agree with Appalachian Voices witness Abbott projecting increases in solar resources under contract with ARBs based on Dominion's forecasted growth in data center load. He believes this approach makes several unsupportable inferential leaps and recommended that tables provided by Mr. Abbott be disregarded. While Mr. Gaskill acknowledged that much of the ARB load is currently associated with data centers, he indicated that growth in data center load does not necessarily equate to growth in new solar or wind resources within PJM under contract with those data centers. Mr. Gaskill asserted that Dominion cannot plan for, and rely on, continued growth in ARB-certified projects to the magnitude Mr. Abbott describes, which he believes would complicate evaluation of interim target requirements.[414]

Mr. Leimann defended Dominion's use of the deficiency penalty for a REC value in the Company's economic analysis. He described the market for Virginia in-state RPS eligible RECs as thinly traded and asserted that the Virginia REC market price may quickly reach the penalty level.[415]

---

[410] Exs. 58, 58-ES (Gaskill rebuttal) at 7-8.
[411] Ex. 58 (Gaskill rebuttal) at 8.
[412] Ex. 61.
[413] Tr. at 500-505 (Gaskill); Ex. 58 (Gaskill rebuttal) at 8-9.
[414] Ex. 58 (Gaskill rebuttal) at 9-10. Mr. Gaskill recognized that ARB certification is available to any commercial or industrial customers with aggregate peak demand over 25 MW. *Id.* at 9.
[415] Ex. 62 (Leimann rebuttal) at 2.

Mr. Leimann responded to Appalachian Voices witness Abbott's position on the use of unbundled RECs. Mr. Leimann explained that, to date, Dominion has relied on market purchases of unbundled RECs for compliance. Through the Company's participation in this market, it has learned that the market does not have many counterparties interested in executing transactions beyond the current or following compliance years. Dominion will continue to explore market options, including through long-term bundled agreements.[416] He acknowledged that there are at least some potential counterparties that are interested in such agreements.[417]

Responding to Staff witness Unger, Mr. Leimann testified that Dominion does not object to working with the GATS Administrator to ensure the RECs retired by Dominion for compliance are attributed to the correct compliance year. Mr. Leimann agreed that the GATS Administrator would need approval from the Commission for changes to RECs that have already been retired in GATS. Because Dominion's exact RPS compliance obligations for 2021 and 2022 may require additional adjustments depending on the outcome of the standalone proceeding, Dominion proposes to wait until Dominion's compliance requirements are finalized before making any necessary updates in GATS, including for: RECs inadvertently retired instead of banked; any RECs retired for the incorrect compliance period; and any re-adjustment of RECs between compliance years. He added that Dominion's recommended one-time update could also incorporate any Commission decisions on whether specific types of RECs are eligible for compliance in specific years.[418]

Turning to questions Staff witness Unger raised about whether certain RECs retired by Dominion for 2022 compliance are RPS-eligible, Mr. Leimann asserted that the GATS Administrator bears the responsibility to maintain accurate information regarding the eligibility of the renewable facilities in its system to meet the requirements of the various RPS standards, which is accomplished through the use of state certification numbers. He described Dominion as "a user of GATS, not the administrator of GATS nor an auditor." He indicated that Dominion – which has retired RECs from 11,655 unique facilities – and market participants need to be able to rely on the accuracy of GATS functionality to filter out any RECs that are not Virginia RPS eligible from being reserved for compliance. Mr. Leimann believes it is reasonable for Dominion to assume that Virginia certification information in GATS is accurate and prudent for Dominion to retire RECs based on such information.[419] He elaborated further on this point:

Mr. Leimann, based on consultation with his counsel, offered Dominion's position that the definitions in effect at the end of a specific compliance year and the five-year banking window would be reasonable to determine REC eligibility for compliance. For example, "for the 2022 compliance year, ... the Company would apply the law as of year-end 2022, and then retire RECs that meet that definition created between 2018 and 2022."[420]

---

[416] *Id.* at 2-3.
[417] Tr. at 539 (Leimann).
[418] Ex. 62 (Leimann rebuttal) at 3-4. Mr. Leimann indicated that updating GATS once should avoid duplication of effort and should allow the Commission to issue one order covering all updates needed. *Id.* at 4.
[419] *Id.* at 4-5; Tr. at 535-36 (Leimann).
[420] Ex. 62 (Leimann rebuttal) at 5-6.

Mr. Leimann provided the following table to summarize the RECs questioned by Staff witness Unger and their status within GATS.[421]

Code	GATS Rules List	Number of RECs
TDF	Non-eligible	23,747
BLQ	Neither	9,976
LFG	Eligible	54,311
OBG	Eligible	649
WH	Eligible	76,657

Mr. Leimann acknowledged that there may not be a basis to use tire-derived fuel RECs ("TDF" above) for 2022 compliance. While these RECs had a state certification number in GATS, they are listed as non-eligible in the Commission's GATS Business Rules.[422] Mr. Leimann also conceded that the other biomass gas RECs ("OBG" above) may fall within the exclusion for out-of-state biomass in Code § 56-585.5 C. While these RECs had state certification numbers under a fuel code that is listed as eligible in the Commission's GATS Business Rules ("Biomass – Other Biomass Gases in VA"), Mr. Leimann acknowledged that these RECs are from Ohio.[423]

However, Mr. Leimann asserted that the questioned landfill gas ("LFG" above), black liquor ("BLQ" above), and waste heat ("WH" above) RECs should be eligible for 2022 RPS compliance. He pointed to provisions in Code §§ 56-576 and 56-585.5 C in support of the Company's position.[424]

Mr. Leimann confirmed that Dominion has not certified that any biomass or waste heat RECs retired during any compliance year meet the RPS requirements. He acknowledged that, pursuant to the Commission's GATS Business Rules, such a certification should have been included. He proposed that Dominion submit such a certification once the final RPS compliance obligation for 2022 is known and offered Dominion's interpretation that the Company would certify broadly that biomass and waste heat RECs meet the applicable legal requirements. If the Company's interpretation is incorrect, Mr. Leimann asked for guidance from the Commission on the certification process.[425]

When contracting for RECs, Mr. Leimann indicated it is unclear what RECs are from the voluntary program versus the new statutory framework. He is not aware of any differentiation between Virginia certification numbers for facilities that would allow such a differentiation. However, he indicated the Company is willing to work to figure out how GATS should be corrected, which he believes would be beneficial to everyone involved.[426]

---

[421] *Id.* at 7.
[422] *Id.*
[423] *Id.* at 7-8.
[424] *Id.*
[425] *Id.* at 8-9. Dominion does not interpret the Commission's directive as a requirement to review the affidavit submitted by each generator for these RECs, a process that Dominion described as burdensome, time-consuming, and cost additive. Mr. Leimann reiterated Dominion's position that the Company is a user of GATS, not its administrator or auditor. *Id.* at 9.
[426] Tr. at 537 (Leimann).

By **Ms. Boschen's** count, the DEQ Report offers approximately 68 recommendations.[427] While Dominion does not oppose most of these recommendations, Ms. Boschen recommended that the Commission reject the following six recommendations, for the reasons summarized below:

- The recommendation by DCR-DNH related to the development and implementation of an invasive species management plan, as the Commission has rejected this recommendation in prior proceedings based on the Company's existing comprehensive integrated vegetation management plan for controlling vegetation, including invasive species, throughout the Company's service territory;[428]

- The recommendation by DCR-DNH to plant Virginia native pollinator plant species, as the Commission has rejected this recommendation in prior proceedings based on the Company's representation that it will comply with any requirements adopted by localities addressing the planting of pollinators;[429]

- The recommendation by DCR-DNH to increase the width of riparian buffers, as the Company will comply with all state and local requirements related to buffering waterways and will implement a voluntary minimum buffer, making this recommendation unnecessary and unreasonable;[430]

- The recommendation by DCR-DNH to conduct an inventory for certain trees and plants at the Michaux project site, as these species are not classified as endangered or threatened, so are not protected by any regulations, and a requirement to inventory these resources prior to construction would result in significant delay to the construction schedule, potentially increasing project costs;[431]

- The recommendation by DCR-DNH to conduct an additional survey to determine bat species presence, as the Company has already completed a survey in accordance with applicable agency guidance and requirements and has received concurrence on the survey results from the agency having jurisdiction, and as further survey activities would result in schedule delays for the project, potentially increasing project costs;[432] and

- The recommendation by DOF to "compensate" for negative impacts to trees, forests, or forest vegetation, as the Commission has rejected this recommendation in prior proceedings based on the lack of a legal requirement to do so; as the Company has already made efforts to minimize forest impacts as practicable; and as such a requirement would add significant additional costs to the projects.[433]

---

[427] Ex. 45 (Boschen rebuttal) at 3.
[428] *Id.* at 3-5.
[429] *Id.* at 3, 6-8.
[430] *Id.* at 3, 8-9.
[431] *Id.* at 3, 10.
[432] *Id.* at 4, 11-12.
[433] *Id.* at 4, 12-14.

ANALYSIS

This Report's Analysis is organized into seven sections. Section I addresses the 2023 RPS Development Plan presented by Dominion. Section II addresses Dominion's requested approval and CPCNs for four utility-scale CE-4 Projects. Section III addresses Dominion's requested prudence determination for the thirteen CE-4 PPAs and CE-4 Distributed Solar PPAs. Section IV addresses Dominion's proposal to consolidate Riders CE and PPA. Section V addresses Dominion's proposed Rider CE increase, which includes analysis of: (i) continuing cost recovery of the approved CE-1, CE-2, CE-3 projects and PPAs; (ii) cost recovery associated with the utility-scale CE-4 Projects for which Dominion requests CPCNs and the proposed PPAs; and (iii) the proposed Alberta and Peppertown solar facilities, for which Dominion requests cost recovery but not CPCNs. Section VI addresses the 2022 Compliance Report presented by Dominion. Section VII addresses concerns raised about the performance of Dominion's solar fleet. Each section of this Analysis includes relevant Code provisions, followed by analysis based on the evidentiary record developed in this case.

I. 2023 RPS DEVELOPMENT PLAN

Code

Subject to many statutory details, Code § 56-585.5 establishes a mandatory RPS Program for Dominion (and APCo). Dominion's annual RPS requirement began at 14% of total energy sold for compliance in 2021 and increases annually, until reaching 100% for compliance in 2045 and thereafter.[434]

If Dominion does not meet an RPS requirement in a year, Code § 56-585.5 requires Dominion to make a deficiency payment to the Virginia Department of Energy ("DOE") that the Company is entitled to recover from its customers.[435] The deficiency payment amount for each REC of any compliance shortfall started at $45 in 2021 (or $75 for a small portion of the requirements) and escalates by 1% each year.[436] Beginning in 2025, the RPS requirement will have a 75% in-state component.[437]

---

[434] Code § 56-585.5 C. "Total electric energy sold" excludes energy sold to ARBs and an amount of annual nuclear generation specified by statute. Code § 56-585.5 A (definition of "Total electric energy"). *See also* Code § 56-585.5 H (excluding from RPS Program requirements certain large customers served by competitive providers prior to April 1, 2019). Section VI of this Report addresses issues raised regarding how to calculate "[t]otal electric energy sold," including the amounts excluded by statute.

[435] Code § 56-585.5 D 5 ("[APCo or Dominion] shall be entitled to recover the costs of such payments as a cost of compliance with the requirements of this subsection pursuant to subdivision A 5 d of § 56-585.1."). The statute directs Virginia DOE to spend any noncompliance penalty amounts as follows: "(i) 50 percent of total revenue shall be directed to job training programs in historically economically disadvantaged communities; (ii) 16 percent of total revenue shall be directed to energy efficiency measures for public facilities; (iii) 30 percent of total revenue shall be directed to renewable energy programs located in historically economically disadvantaged communities; and (iv) four percent of total revenue shall be directed to administrative costs." Code § 56-585.5 D 5.

[436] Code § 56-585.5 D 5. The $75 deficiency penalty amount for requirements related to smaller resources (one MW or less) also escalates 1% each year. *Id.*

[437] Code § 56-585.5 C.

Dominion seeks approval of its 2023 RPS Development Plan pursuant to Code § 56-585.5 D 4, which states as follows:

> In connection with the requirements of this subsection, [APCo and Dominion][438] shall, commencing in 2020 and concluding in 2035, submit annually a plan and petition for approval for the development of new solar and onshore wind generation capacity. Such plan shall reflect, in the aggregate and over its duration, the requirements of subsection D concerning the allocation percentages for construction or purchase of such capacity. Such petition shall contain any request for approval to construct such facilities pursuant to subsection D of § 56-580 and a request for approval or update of a rate adjustment clause pursuant to subdivision A 6 of § 56-585.1 to recover the costs of such facilities. Such plan shall also include the utility's plan to meet the energy storage project targets of subsection E, including the goal of installing at least 10 percent of such energy storage projects behind the meter. In determining whether to approve the utility's plan and any associated petition requests, the Commission shall determine whether they are reasonable and prudent and shall give due consideration to (i) the RPS and carbon dioxide reduction requirements in this section, (ii) the promotion of new renewable generation and energy storage resources within the Commonwealth, and associated economic development, and (iii) fuel savings projected to be achieved by the plan. Notwithstanding any other provision of this title, the Commission's final order regarding any such petition and associated requests shall be entered by the Commission not more than six months after the date of the filing of such petition.

The referenced "requirements of this subsection" (*i.e.*, Code § 56-585.5 D) include the following provisions:

> [APCo and Dominion] shall petition the Commission for necessary approvals to procure zero-carbon electricity generating capacity as set forth in this subsection and energy storage resources as set forth in subsection E.

As applicable to Dominion, the referenced petition requirements for "zero-carbon electricity generating capacity"[439] have filing deadlines and amounts for 2035 and interim deadlines and amounts for 2024, 2027, and 2030. The statutory provisions for 2024, 2027, and 2035 are shown below.

> By December 31, 2024, [Dominion] shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 3,000 [MW] of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or

[438] Various Code provisions refer to APCo as the "Phase I Utility" and Dominion as the "Phase II Utility." This Report uses the names of these companies.
[439] Code § 56-585.5 D.

onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by [Dominion].[440]

By December 31, 2027, [Dominion] shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 3,000 [MW] of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by [Dominion].[441]

By December 31, 2035, [Dominion] shall petition the Commission for necessary approvals to (i) construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of 16,100 [MW] of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, which shall include 1,100 [MW] of solar generation of a nameplate capacity not to exceed three [MW] per individual project and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar facilities owned by persons other than a utility, including utility affiliates and deregulated affiliates and (ii) pursuant to § 56-585.1:11, construct or purchase one or more offshore wind generation facilities located off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the Commonwealth with an aggregate capacity of up to 5,200 [MW]. At least 200 [MW] of the 16,100 [MW] shall be placed on previously developed project sites.[442]

Code § 56-585.5 G 1 refers to the above petition requirements as "procurement requirements"[443] and states in part as follows:

To the extent that an [ARB] contracts for the capacity of new solar or wind generation resources pursuant to this subsection, the aggregate amount of such nameplate capacity shall be offset from the utility's procurement requirements pursuant to [Code § 56-585.5 D].

[440] Code § 56-585.5 D 2 a.
[441] Code § 56-585.5 D 2 b.
[442] Code § 56-585.5 D 2.
[443] In some contexts, procurement can refer to purchases. However, as shown above, "procure" is used in the December 31, 2024, and 2027 statutory petition requirements to refer to the total of Company-owned projects and purchases. Code § 56-585.5 D 2 a and b ("35 percent of such generating capacity procured…").

As applicable to Dominion, the referenced petition requirements for "energy storage resources"[444] include the following:

> To enhance reliability and performance of the utility's generation and distribution system, [APCo and Dominion] shall petition the Commission for necessary approvals to construct or acquire new, utility-owned energy storage resources.[445]
>
> ....
>
> By December 31, 2035, [Dominion] shall petition the Commission for necessary approvals to construct or acquire 2,700 [MW] of energy storage capacity....[446]
>
> ....
>
> After July 1, 2020, at least 35 percent of the energy storage facilities placed into service shall be (i) purchased by the public utility from a party other than the public utility or (ii) owned by a party other than a public utility, with the capacity from such facilities sold to the public utility. By January 1, 2021, the Commission shall adopt regulations to achieve the deployment of energy storage for the Commonwealth required in subdivisions 1 and 2, including regulations that set interim targets and update existing utility planning and procurement rules. The regulations shall include programs and mechanisms to deploy energy storage, including competitive solicitations, behind-the-meter incentives, non-wires alternatives programs, and peak demand reduction programs.[447]

Among the interim storage targets that the above Code provisions directed the Commission to adopt by regulation is a target for Dominion to petition the Commission for approval to construct or acquire 250 MW of storage by December 31, 2025.[448]

Case participants also identified energy efficiency assumptions in Dominion's modeling conducted in support of its 2023 IRP and RPS Development Plan. Code § 56-596.2 B directs Dominion to implement energy efficiency programs and measures to achieve total annual energy savings that escalate from 1.25% in 2022 to 5.0% in 2025, and subsequently are set at levels determined by the Commission.[449]

---

[444] Code § 56-585.5 D.
[445] Code § 56-585.5 E.
[446] Code § 56-585.5 E 2.
[447] Code § 56-585.5 E 5.
[448] 20 VAC 5-335-30 B 1.
[449] The statutory baseline for these percentages is average annual energy jurisdictional retail sales in 2019. Code § 56-596.2 B 2.

240230001

Analysis of 2023 RPS Development Plan

Dominion instructed its model to select solar and energy storage resources consistent with the 2023 RPS Development Plan for Alternative Plans B and D from the 2023 IRP. For IRP Alternative Plans C and E, Dominion instructed its model to select all new generation resources on a least-cost basis without regard to the statutory solar, wind, and energy storage petition requirements.[450] Dominion summarized its five alternative plans from the 2023 IRP as follows:[451]

> Plan A: This Alternative Plan presents a least-cost plan that meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA. The Company presents this Alternative Plan in compliance with prior Commission orders and for cost comparison purposes only. It is important to emphasize that Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.
>
> Plan B: This Alternative Plan includes the significant development of solar, wind, and energy storage envisioned by the VCEA, petitioned by 2035 and built by 2038. Plan B includes the development of six new [nuclear] small modular reactors ... starting in 2034 and a second offshore wind project, providing carbon-free power. This plan does require an increase in the Company's ability to import capacity and energy by 2040. Plan B also preserves existing generation and includes several new gas combustion turbines to address future energy and system reliability needs.
>
> Plan C: This Alternative Plan is like Plan B in preserving existing generation to address future system reliability, stability, and energy independence issues, with identical assumptions regarding the retirement of existing Company-owned carbon-emitting generation. Plan C differs from Plan B in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.
>
> Plan D: This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045, resulting in zero CO_2 emissions from the Company's fleet in 2046. In order to retire all carbon-emitting units by the end of 2045, the Company will need to build and buy significant incremental capacity to reliably meet customer load. Plan D shows the Company building over 4,500 MW of incremental energy storage and more than 3,000 MW of incremental [nuclear small modular reactors] to meet this need when compared to Plan B. Even with these additional resources, Plan D results in the Company purchasing 10,800 MW of capacity in 2045 and beyond, raising significant concerns about system reliability and energy independence, including

[450] Ex. 4 (2023 RPS Development Plan) at 12.

[451] *Id.* at 10-11. *See also id.* at Attachment 6 (summary of alternative plan modeling assumptions).

over-reliance on out-of-state capacity to meet customer needs. This Plan will also require a substantial increase in energy purchase limits. Over time as more renewable energy and energy storage resources are added to the system and as other technology advances, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan D approach to maintain system reliability.

Plan E: This Alternative Plan is like Plan D in retiring all Company-owned carbon-emitting generation by the end of 2045. Plan E differs from Plan D in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Like Plan D, Plan E would require the Company to build and buy significant incremental capacity and energy to reliably meet customer load. Over time as more renewable energy and energy storage resources are added to the system, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan E approach to maintain system reliability.

Dominion presented the results of the long-term modeling for its 2023 IRP using the following table.[452]

	Plan A	**Plan B**	**Plan C**	**Plan D**	**Plan E**
NPV Total ($B)	$109.70	$127.70	$127.20	$140.90	$138.00
Approximate CO_2 Emissions from Company in 2048 (Metric Tons)	43.8 M	35.9 M	36 M	0 M	0 M
Solar (MW)	10,800 15-yr 19,800 25-yr	10,875 15-yr 19,875 25-yr	10,800 15-yr 19,800 25-yr	10,875 15-yr 23,955 25-yr	11,094 15-yr 24,294 25-yr
Wind (MW)	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr
Storage (MW)	1,050 15-yr 3,960 25-yr	2,370 15-yr 5,190 25-yr	2,220 15-yr 5,220 25-yr	2,370 15-yr 9,780 25-yr	2,910 15-yr 10,350 25-yr
Nuclear (MW)	-- 15-yr -- 25-yr	804 15-yr 1,608 25-yr	804 15-yr 1,608 25-yr	1,608 15-yr 4,824 25-yr	1,072 15-yr 4,288 25-yr
Natural Gas Fired (MW)	5,905 15-yr 9,300 25-yr	2,910 15-yr 2,910 25-yr	2,910 15-yr 2,910 25-yr	970 15-yr 970 25-yr	970 15-yr 970 25-yr
Retirements (MW)	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr 11,399 25-yr	-- 15-yr 11,399 25-yr

Dominion concluded that IRP Alternative "Plans B through E all show the significant development of solar and energy storage envisioned by the VCEA, suggesting it remains prudent to proceed with development as set forth in this 2023 RPS Development Plan."[453]

All of Dominion's alternative plans – including those modeled without regard for the statutory petition requirements – assume a significant expansion of renewable generation in the Commonwealth continuing through 2035. This expansion generally appears to be aligned with

[452] *Id.* at 12.
[453] *Id.*

the RPS requirements and the 2035 petition requirement of the VCEA. Most of the plans also assume a significant expansion of storage, which appears generally aligned with the petition requirements of the VCEA. While the future generation and storage represented in the 2023 IRP and RPS Development Plan are largely generic, Dominion's continuing development of its own projects and the use of RFPs to acquire developments and PPAs results in actual proposed projects and PPAs such as those proposed in the instant proceeding.[454]

Appalachian Voices raised an issue that suggests the Company's 2023 RPS Development Plan may contemplate solar development that is more aggressive than the Code requires in one aspect. As shown in the Code section above, the solar and onshore wind petition requirements in Code § 56-585.5 D include the interim requirement for 3,000 MW by the end of 2024; another 3,000 MW by the end of 2027; and ultimately 16,100 MW by the end of 2035. Notably, the Code also directs that the solar and onshore wind petition requirements in Code § 56-585.5 D "shall be offset" by the aggregate amount of ARB[455] contractual capacity for new solar and wind generation.[456] If all of Dominion's statutory petition requirements are offset by the 1,972 MWs under such contracts certified as of June 30, 2023, Appalachian Voices witness Abbott asserted that Dominion had already exceeded the interim statutory petition requirements for 2024 and 2027 before the instant Petition was filed.[457] Appalachian Voices argued that while the VCEA requires a transition to clean renewable energy sources, "that requirement does not mean that utilities are free to build more than what they actually need to comply with the law."[458]

Dominion agreed that solar capacity under contract with ARBs counts toward the statutory petition requirements, and included such an offset to the *final* cumulative petition requirement in the 2023 RPS Development Plan.[459] However, Dominion indicated that the Commission has not determined a methodology for the statutory offset and raised questions about whether or how this offset would be applied to the *interim* petition requirements.[460] More specifically, Dominion indicated it was unclear how certified ARB capacity, which can be in-state or out-of-state, would offset development targets for in-state solar and wind resources, particularly in light of the in-state REC requirements of Code § 56-585.5 C.[461] Dominion also indicated the fact that ARB certification is voluntary and occurs annually could complicate the evaluation of interim target requirements of Code § 56-585.5 D if ARB capacity used to offset interim targets is not certified in subsequent years.[462] Based on conversations Dominion witness Gaskill has had with ARBs, he believes decertification is an option ARBs will use in the future

---

[454] *See* Code § 56-585.5 D 3 ("[APCo and Dominion] shall, at least once every year, conduct a request for proposals for new solar and wind resources."); Code § 56-585.5 I ("In any petition by [APCo or Dominion] for a certificate of public convenience and necessity to construct and operate an electrical generating facility that generates electric energy derived from sunlight submitted pursuant to § 56-580, such utility shall demonstrate that the proposed facility was subject to competitive procurement or solicitation as set forth in subdivision D 3.").
[455] As discussed in this Report's Summary of the Record, the acronym "ARB" refers to the term "accelerated renewable energy buyer," which is defined in Code § 56-585.5.
[456] Code § 56-585.5 G 1 (second to last sentence).
[457] Ex. 35 (Abbott) at 9.
[458] Tr. at 548 (James).
[459] Ex. 4 (2023 RPS Development Plan) at 5; Tr. at 500 (Gaskill).
[460] *See, e.g.*, Tr. at 500 (Gaskill).
[461] Ex. 58 (Gaskill rebuttal) at 9.
[462] *Id.* at 8-9.

as RPS requirements and corporate goals increase.[463]

In applying the statutory ARB offset of the petition requirements, I do not see geography as a complicating factor. The plain language of the Code: (1) allows ARB customers to certify in-state or out-of-state capacity,[464] and (2) does not include a geographical limit on the required offset to the petition requirements.[465] On the other hand, I agree with Dominion that the potential for ARB capacity to decrease over time (as the Code empowers ARBs to decide annually whether to recertify or decertify capacity) is a complicating factor. However, Dominion's 2023 RPS Development Plan indicates that this year's Petition brings Dominion well above the 2024 interim petition requirement without *any* offset for ARB capacity.[466] If so, a future decertification of ARB capacity would not appear to impact Dominion's compliance with the statutory requirement for petitions through December 31, 2024.

While Dominion's 2023 RPS Development Plan voices concern about REC availability and represents that "the Company will pursue all available avenues to achieve RPS Program compliance in the most cost-effective manner,"[467] Appalachian Voices highlighted Dominion's current strategy of modeling and purchasing unbundled RECs only from the spot market, rather than through long-term REC-only contracts. Appalachian Voices recommended that the Commission direct Dominion to proactively seek out long-term purchase agreements for unbundled RECs.[468] Appalachian Voices witness Abbott acknowledged that developers may not be willing to make offers for long-term purchase agreements for unbundled RECs and that any such offers may not be at attractive prices. However, he believes pursuing a strategy of executing such agreements would promote new renewable resources in the Commonwealth at a potentially lower cost to ratepayers.[469]

Dominion does not believe such action is necessary at this time. Dominion indicated that its staggered approach to procuring RECs by purchasing bundled products for longer terms, coupled with shorter term REC purchases in the spot market, helps mitigate the risks of REC procurement.[470] Dominion did not rule out the possibility that the Company might find long-term agreements for unbundled RECs necessary in the future, but the Company does not currently see a need for, or benefit from, such agreements.[471] Dominion acknowledged that there are at least some potential counterparties that are interested in such agreements.[472]

---

[463] Tr. at 501-05 (Gaskill).

[464] Code § 56-585.5 G 1 ("An [ARB] may contract ... to obtain ... bundled capacity, energy, and RECs from solar or wind generation resources *located within the PJM region....*") (emphasis added).

[465] *Id.* ("To the extent that an [ARB] contracts for the capacity of new solar or wind generation resources pursuant to this subsection, the aggregate amount of such nameplate capacity shall be offset from the utility's procurement requirements pursuant to subsection D.").

[466] *See, e.g.*, Ex. 4 (2023 RPS Development Plan) at 4 (showing a total of 3,744 MW of solar and onshore wind construction and purchases, including the proposed Rider CE resources).

[467] *See, e.g.*, id. at 15.

[468] Ex. 35 (Abbott) at 14-16.

[469] *Id.* at 16.

[470] Ex. 47 (Keefer rebuttal) at 4.

[471] Tr. at 376 (Keefer).

[472] Tr. at 539 (Leimann).

As discussed below in Sections II, III, and V of this Report's Analysis, the costs of the solar resources proposed in the instant case are elevated and the customer impacts associated with RPS compliance are escalating. These customer impacts support compliance planning that leaves no stone unturned, in my opinion. Consequently, now appears to be an appropriate time for the Company to solicit unbundled REC agreements to better determine whether such agreements could be part of a lower cost compliance portfolio. I recommend that the Commission direct Dominion to solicit long-term agreements for unbundled RECs, either by expanding its existing RFP process or through a parallel competitive process. A formal competitive procurement process – like the one Dominion currently employs for compliance PPAs and development assets[473] – should illuminate for Dominion, the Commission, and stakeholders as to the availability and cost of long-term unbundled REC agreements.

Based on the record and the Code – including consideration of statutory RPS and CO_2 reduction requirements, promotion of new renewable generation and energy storage resources within the Commonwealth, associated economic development, and projected fuel savings[474] – Dominion's 2023 RPS Development Plan generally appears reasonable as a planning document provided the Company's current development of solar and onshore wind resources is based on factors other than the 2024 interim statutory petition requirement of Code § 56-585.5 D. The significant extent of Dominion's solar development thus far – with or without consideration of statutory ARB offsets to the petition requirements of Code § 56-585.5 D – should allow Dominion to focus on need, costs and benefits, and other factors that inform whether the public convenience and necessity require specific projects and whether specific PPAs are prudent.[475] In addition, given the proposed costs in this proceeding and Dominion's stated concern about the availability of RECs, Dominion should be directed to solicit long-term agreements for unbundled RECs, for potential inclusion in the Company's RPS compliance portfolio.

Future Modeling and Planning Assumptions, Including Overlapping IRP Issues

The *2020 RPS Plan Order* found that "to a certain extent, [Dominion's] modeling inputs and assumptions should be consistent for purposes of the IRP and RPS proceedings."[476] In the instant case, Staff and Appalachian Voices confirmed that Dominion's modeling for the 2023 RPS Development Plan is consistent with the Company's modeling for its 2023 IRP.[477]

Staff identified the following areas of Staff concern with the Company's modeling that Staff raised in the pending 2023 IRP Case: (1) the average annual capacity factors of onshore wind resources used in the model; (2) the effective load carrying capability capacity values of solar resources used in the model; (3) the estimated construction costs/timelines of small modular nuclear reactors made available for selection in the model; (4) Dominion's energy, peak load, and commodities forecast; and (5) the modeling of 5% energy efficiency savings

[473] As the Commission is aware, APCo issues RFPs for unbundled REC agreements. *See, e.g., 2023 APCo RPS Plan Order* at 8 (directing a requested modification to APCo's RFP for REC-only purchases, allowing for contract terms of not less than five years).
[474] Code § 56-585.5 D 4.
[475] Such factors can include the in-state REC requirements of Code § 56-585.5 C, as cited by Dominion.
[476] *2020 RPS Plan Order*, 2021 S.C.C. Ann. Rep. at 246.
[477] Ex. 37 (Brunelle) at 20; Ex. 35 (Abbott) at 4.

attributable to Dominion's current and projected demand side management activities.[478]

Similarly, Appalachian Voices identified several issues it raised about the Company's modeling in the pending 2023 IRP Case, including: (1) modeling assumptions for ARBs; and (2) Dominion's capacity price forecast.[479] Appalachian Voices also emphasized its recommendation in the 2023 IRP Case that Dominion should perform a locational analysis, especially for energy storage resources, given that Dominion's forecasted load growth is almost exclusively driven by data centers, 80% of which are located in Northern Virginia.[480]

Rather than re-litigate such IRP issues in this RPS plan case, Dominion, Staff, and Appalachian Voices agreed that any Commission directives from the 2023 IRP Case on relevant issues should be reflected in the Commission's order in the instant case, and consequently future RPS plan filings.[481] Because the Commission did not reach a majority decision in the 2023 IRP Case, I find this recommendation is moot.[482]

Staff recommended that Dominion continue to monitor new and developing energy storage technologies and refine its assumptions in future IRP and RPS plan proceedings as appropriate.[483] Dominion does not oppose this recommendation,[484] which I find is reasonable.

Appalachian Voices asserted that two aspects of its recommendation for locational analysis of energy storage resources reach into RPS plan cases. Specifically, Appalachian Voices recommended that locational analysis be used in an economic analysis submitted in support of specific energy storage resources and also in the selection process for such resources.[485] Appalachian Voices indicated that its recommended analysis could be performed either by modifying the PLEXOS model used by the Company or through protocols or an analysis outside of PLEXOS.[486] I recommend that Dominion continue to explore ways to value location when selecting potential resource additions. Currently, if Dominion gets two energy storage proposals that are comparable, Dominion will consider proximity to a load center as a qualitative consideration.[487] Historic locational marginal pricing posted by PJM coupled with a review of queued generation projects and public information about planned transmission projects could, for example, potentially provide some indicative information about (positive or negative) locational value.[488] Because all resources could be implicated by locational value, and absent a

---

[478] Ex. 37 (Brunelle) at 20.
[479] *See, e.g.,* Ex. 35 (Abbott) at 8-13, 19-24.
[480] Ex. 35 (Abbott) at 24-31.
[481] *See, e.g.,* Ex. 37 (Brunelle) at 20; Ex. 35 (Abbott) at 5; Tr. at 606 (Ryan).
[482] On February 1, 2024, the Commission provided a notification indicating that the Commission did not reach a majority decision in the 2023 IRP Case.
[483] Ex. 37 (Brunelle) at 27.
[484] Ex. 46 (Flowers rebuttal) at 7.
[485] *See, e.g.,* Tr. at 194 (Abbott); 550-51 (James). In the instant case, these were not two distinct processes – *i.e.*, the results of the model run Dominion used to evaluate resources were also submitted with the Petition in support of the resources. Tr. at 137-38 (Keefer).
[486] Tr. at 551 (James).
[487] Tr. at 364-65 (Flowers).
[488] *See, e.g.,* Tr. at 367 (Flowers) (indicating that historic nodal PJM locational marginal prices could provide a snapshot in time on historic price volatility or variability, which is an indicator of where system constraints may be, but recognizing that an asset may operate over a 35-year period during when system changes will occur).

directive from the 2023 IRP Case, I do not recommend that the Commission direct Dominion to modify the PLEXOS model based on the record of this RPS plan case.

For another issue involving the overlap between IRP and RPS plan proceedings, Staff and Consumer Counsel recommended that Dominion post, in its eRoom for future RPS plan cases, the Company's most recent IRP and the Excel files for the associated appendices.[489] Dominion does not oppose this recommendation,[490] assuming the IRP continues to be filed before or at the same time as an RPS plan filing.[491] I recommend that the Commission adopt this uncontested recommendation. While the Commission denied a similar recommendation last year,[492] at that time it was opposed by Dominion, which no longer opposes the recommendation.

II. CPCNs

Code

Dominion seeks CPCNs and approval to construct and operate four utility-scale CE-4 Projects pursuant to Code § 56-580 D, which states in part as follows:

> The Commission shall permit the construction and operation of electrical generating facilities in Virginia upon a finding that such generating facility and associated facilities (i) will have no material adverse effect upon reliability of electric service provided by any regulated public utility, (ii) are required by the public convenience and necessity, if a petition for such permit is filed after July 1, 2007, and if they are to be constructed and operated by any regulated utility whose rates are regulated pursuant to § 56-585.1, and (iii) are not otherwise contrary to the public interest. In review of a petition for a certificate to construct and operate a generating facility described in this subsection, the Commission shall give consideration to the effect of the facility and associated facilities on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact as provided in § 56-46.1.... In order to avoid duplication of governmental activities, any valid permit or approval required for an electric generating plant and associated facilities issued or granted by a federal, state or local governmental entity charged by law with responsibility for issuing permits or approvals regulating environmental impact and mitigation of adverse environmental impact or for other specific public interest issues such as building codes, transportation plans, and public safety, whether such permit or approval is prior to or after the Commission's decision, shall be deemed to satisfy the requirements of this section with respect to all matters that (i) are governed by the permit or approval or (ii) are within the authority of, and were considered by, the governmental entity in issuing such permit or approval, and the Commission shall impose no additional conditions with respect to such matters....

---

[489] Tr. at 241-42 (Brunelle); Tr. at 570 (Farmer).
[490] Ex. 49 (Morton rebuttal) at 16.
[491] Tr. at 400 (Morton).
[492] *2022 RPS Plan Order* at 8 (Recommendation 4).

Code § 56-585.1 A 6 states in part as follows:

In any application to construct a new generating facility, the utility shall include, and the Commission shall consider, the social cost of carbon, as determined by the Commission, as a benefit or cost, whichever is appropriate.... The Commission may adopt any rules it deems necessary to determine the social cost of carbon and shall use the best available science and technology, including the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, published by the Interagency Working Group on Social Cost of Greenhouse Gases from the United States Government in August 2016, as guidance. The Commission shall include a system to adjust the costs established in this section with inflation.

....

The construction or purchase by a utility of one or more generation facilities with at least one megawatt of generating capacity, and with an aggregate rated capacity that does not exceed 16,100 [MW], including rooftop solar installations with a capacity of not less than 50 [kW], and with an aggregate capacity of 100 [MW], that use energy derived from sunlight or from onshore wind and are located in the Commonwealth or off the Commonwealth's Atlantic shoreline, regardless of whether any of such facilities are located within or without the utility's service territory, is in the public interest.

....

Code § 56-46.1 states in part as follows:

Whenever the Commission is required to approve the construction of any electrical utility facility, it shall give consideration to the effect of that facility on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact. In order to avoid duplication of governmental activities, any valid permit or approval required for an electric generating plant and associated facilities issued or granted by a federal, state or local governmental entity charged by law with responsibility for issuing permits or approvals regulating environmental impact and mitigation of adverse environmental impact or for other specific public interest issues ..., whether such permit or approval is granted prior to or after the Commission's decision, shall be deemed to satisfy the requirements of this section with respect to all matters that (i) are governed by the permit or approval or (ii) are within the authority of, and were considered by, the governmental entity in issuing such permit or approval, and the Commission shall impose no additional conditions with respect to such matters.... In every proceeding under this subsection, the Commission shall receive and give consideration to all reports that relate to the proposed facility by state agencies concerned with environmental protection.... Additionally, the Commission (a) shall consider the effect of the proposed facility on economic

> development within the Commonwealth, including but not limited to furtherance of the economic and job creation objectives of the Commonwealth Clean Energy Policy set forth in § 45.2-1706.1, and (b) shall consider any improvements in service reliability that may result from the construction of such facility.[493]

The Commission also considers environmental justice in RPS plan proceedings. The VEJ Act codified a policy for the Commonwealth "to promote environmental justice,"[494] which is defined as "the fair treatment and meaningful involvement of every person, regardless of race, color, national origin, income, faith, or disability, regarding the development, implementation, or enforcement of any environmental law, regulation, or policy."[495] Enactment Clause 7 of the VCEA states in part that:

> it shall be the policy of the Commonwealth that the [Commission], [Virginia DOE], and Virginia Council on Environmental Justice, in the development of energy programs, job training programs, and placement of renewable energy facilities, shall consider whether and how those facilities and programs benefit local workers, historically economically disadvantaged communities, as defined in § 56-576 of the Code of Virginia, as amended by this act, veterans, and individuals in the Virginia coalfield region that are located near previously and presently permitted fossil fuel facilities or coal mines.[496]

Additionally, Code § 56-585.1 A 6 states in part that "[t]he Commission shall ensure that the development of new, or expansion of existing, energy resources or facilities does not have a disproportionate adverse impact on historically economically disadvantaged communities."[497] As defined in Code § 56-576, "'Historically economically disadvantaged community' means (i) a community in which a majority of the population are people of color or (ii) a low-income geographic area."[498]

Dominion does not seek a CPCN for any of the facilities it would construct, own, or operate to interconnect the CE-4 Projects.[499] A CPCN is not required for facilities that are "ordinary extensions or improvements in the usual course of business."[500] Staff agreed that such facilities appear to be ordinary and therefore do not require a CPCN.[501]

---

[493] Code § 56-46.1 A.
[494] Code § 2.2-235.
[495] Code § 2.2-234.
[496] 2020 Va. Acts chs. 1193, 1194, Enactment Clause 7.
[497] Code § 56-585.1 A 6.
[498] A "Low-income geographic area," in turn, is defined as "any locality, or community within a locality, that has a median household income that is not greater than 80 percent of the local median household income, or any area in the Commonwealth designated as a qualified opportunity zone by the U.S. Secretary of the Treasury via his delegation of authority to the Internal Revenue Service." Code § 56-576. A "Community in which a majority of the population are people of color" is defined as "a U.S. Census tract where more than 50 percent of the population comprises individuals who identify as belonging to one or more of the following groups: Black, African American, Asian, Pacific Islander, Native American, other non-white race, mixed race, Hispanic, Latino, or linguistically isolated." *Id.*
[499] Ex. 3 (Petition) at 10, n.11.
[500] Code § 56-265.2 A 1. Nor is review under Code § 56-46.1 required for such facilities. Code § 56-46.1 J.
[501] *See, e.g.*, Tr. at 264 (Glattfelder).

Dominion also does not seek a CPCN for Peppertown or Alberta, the CE-4 Distributed Solar Project.[502] Commission Rule 20 VAC 5-302-10 provides that generation facilities "with rated capacities of 5 MW or less may be undertaken without complying with the filing requirements established by [20 VAC 5-302-10 *et seq.*]. Persons desiring to construct such facilities shall (i) submit a letter to the Director of the Division of Energy Regulation stating the location, size and fuel type of the facility, and (ii) comply with all other requirements of federal, state and local law."[503] Dominion has followed this process for Peppertown (5 MW) and the CE-4 Distributed Solar Project (3 MW).[504]

Analysis

The four CE-4 Projects for which Dominion seeks generation CPCNs are utility-scale projects with nameplate capacity totaling 329 MW. The table below provides some summary information for each of these proposed solar projects.[505]

Project and Location	Acres	Size MW	Estimated Cost	RFP[506]	COD
Beldale Cartersville and Duke Rds., Powhatan	323	57	$157.7 million ($2,766/kW)	2022	2026
Blue Ridge Concord and Tight Squeeze Rds., Pittsylvania	1,455	95	$299.4 million ($3,152/kW)	2020	2026
Bookers Mill 1785 Maon Rd., Richmond County	820	127	$249.0 million ($1,961/kW)	No	2024
Michaux Thornfield Dr., Pittsylvania and Henry	1,352	50	$133.1 million ($2,661/kW)	2022	2026

(i) Impact on Reliability

As shown above, the first of three criteria for evaluating CPCN requests under Code § 56-580 D is whether the proposed facilities "have no material adverse effect upon reliability of electric service provided by any public utility." PJM has assessed the transmission system reliability effects of all four of these CE-4 Projects. More specifically, these projects all have executed Interconnection Service Agreements to interconnect with Dominion's or American Electric Power Company's transmission system.[507] Such agreements obligate Dominion to address identified adverse system reliability impacts caused by the interconnection of its solar

[502] *See, e.g.*, Ex. 3 (Petition) at 8; Ex. 11 (Flowers direct) at 7.
[503] The Commission's Division of Energy Regulation is now the Division of Public Utility Regulation.
[504] *See, e.g.*, Ex. 11 (Flowers direct) at 7 and attached Sched. 10.
[505] *See, e.g.*, *id.* at attached Scheds. 4, 5-6 (both corrected), 7.
[506] Beldale and Michaux were selected from the 2022 Development RFP. *Id.* at attached Scheds. 4, 7, p. 1. Blue Ridge was not selected from the 2020 Solar-Wind-Storage RFP. *Id.* at attached Sched. 5 (corrected), p. 1. Dominion acquired Bookers Mill in 2021 for a specific customer. *Id.* at attached Sched. 6, p. 1.
[507] Ex. 12. Blue Ridge and Michaux would interconnect with American Electric Power Company's transmission system, while Beldale and Bookers Mill would interconnect with Dominion's transmission system. *Id.*

generation.[508] Staff identified no reliability concerns associated with the interconnection of these facilities.[509]

No record evidence indicates that the addition of any of these four CE-4 Projects would have a material adverse effect on reliability.

(ii) Required by the Public Convenience and Necessity

The second of three criteria for evaluating CPCN requests under Code § 56-580 D is whether the proposed facilities "are required by the public convenience and necessity." This standard includes consideration of need, cost, the social cost of carbon as a benefit, environmental impact, economic development, and environmental justice. These considerations are discussed below for the four CE-4 Projects for which Dominion seeks CPCNs.

Need for Beldale, Blue Ridge, Bookers Mill, and Michaux

According to Dominion, the CE-4 Projects are needed for RPS compliance, energy, and capacity.[510] In Staff's opinion, the primary need for the proposed CE-4 Projects is compliance with parts of the VCEA, while the provision of capacity and energy to Dominion's customers is a secondary need.[511] Dominion disagreed that its need for capacity and energy is secondary, asserting that its 2023 load forecast "reflects a need for capacity now."[512] Dominion identified its projections that the Company's capacity and energy needs will grow, even under modeling assumptions: (i) of normal weather; and (ii) that no existing generation units are retired. Due to Dominion's responsibility for system reliability, Dominion also cautioned against overreliance on market purchases, for which there are limits on the amount Dominion can purchase and physically receive.[513]

Appalachian Voices and Staff expressed concerns about Dominion's load projections, which, among other things, are used to estimate the Company's future RPS requirements.[514] In particular, Appalachian Voices focused on Dominion's unprecedented load growth forecasted for data centers and asserted that it is unreasonable to assume that the capacity associated with ARBs, most of which are data centers, "will remain constant."[515] Staff also alluded to concerns it raised in the 2023 IRP Case about Dominion's assumed level of energy efficiency in the load forecast,[516] an assumption that can also affect the projected RECs needed for RPS compliance.

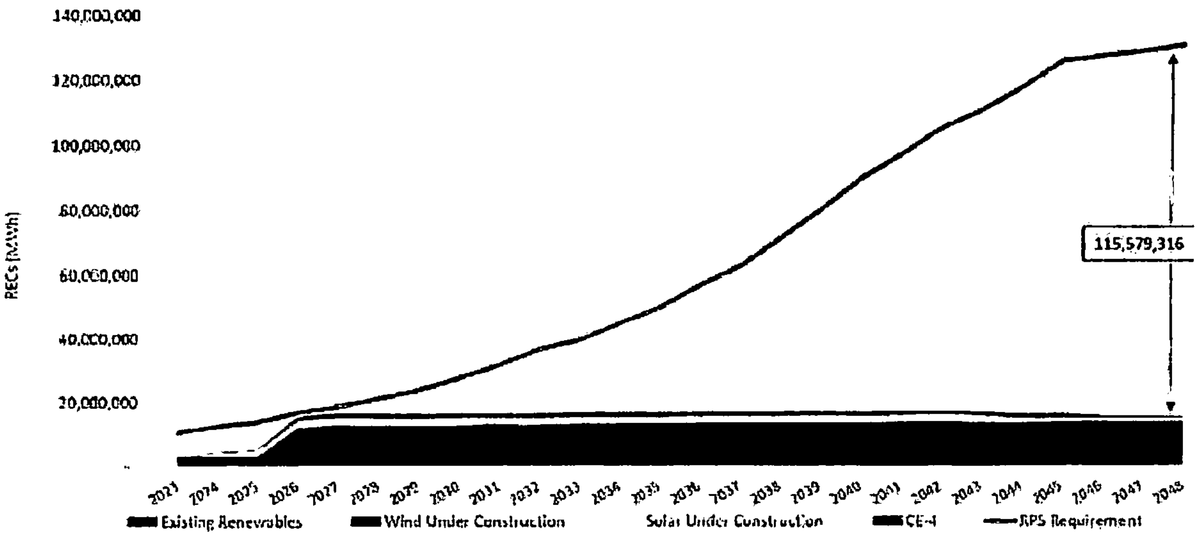
---

[508] *See, e.g.*, Ex. 12 at Blue Ridge Interconnection Service Agreement, pp. 12-13 (identifying network upgrades and cost responsibility).
[509] Tr. at 264 (Glattfelder).
[510] *See, e.g.*, Ex. 20 (Morton direct) at 3-10.
[511] *See, e.g.*, Ex. 40 (Glattfelder) at 32.
[512] Ex. 49 (Morton rebuttal) at 4.
[513] *Id.* at 4-5.
[514] Ex. 4 (2023 RPS Development Plan) at Attachment 8.
[515] Ex. 35 (Abbott) at 10-11.
[516] *See, e.g.*, Ex. 37 (Brunelle) at 20.

240230061

Dominion's evidence offered in support of a compliance need for the CE-4 Projects shows a large need – both in the near-term and the longer-term – for compliance RECs, as illustrated below.[517]

Estimated RPS Program Requirements Through 2048



The "CE-4" sliver of light blue below the "RPS Requirement" line illustrates the projected RECs created collectively by the CE-4 Projects, the CE-4 Distributed Solar Project, and the CE-4 PPAs.[518] The first full year when the Company expects all the CE-4 Projects would be operational is 2027.[519] That year, the statutory RPS requirement will have reached 32% (on its climb to 100%), and will have a 75% in-state component.[520] The CE-4 Projects are expected to contribute approximately 636,000 Virginia RECs,[521] or 3.4% of the estimated REC need for 2027.[522] This is approximately one-third of Dominion's estimated *increase* in REC requirements from 2026 to 2027.[523] Even with approval of the proposed projects and PPAs and a large offshore wind facility becoming operational, a large near-term need for RECs from future projects and/or purchases would remain.[524]

I acknowledge the degree of uncertainty associated with load growth projections – which, along with the annual statutory escalation in the RPS percentage, explain the upward trajectory of the RPS requirement shown in the chart above. However, I note that a large portion of Dominion's projected load is offset in the RPS obligation calculation by projected nuclear

---

[517] Ex. 20 (Morton direct) at 5.
[518] *Id.* at 4.
[519] *See, e.g., id.* at 5.
[520] Code § 56-585.5 C.
[521] Ex. 20 (Morton direct) at 5. One REC is generated from each MWh of applicable energy production. *Id.*
[522] Ex. 4 (2023 RPS Development Plan) at Attachment 10. 635,730 / 18,793,649 = 3.4%.
[523] *Id.* 18,793,649 - 16,897,650 = 1,895,999. 635,730 / 1,895,999 = 33.5%
[524] Dominion plans to bank Virginia RECs until 2025, when the in-state requirement begins. *Id.* at Attachment 10, n.2.

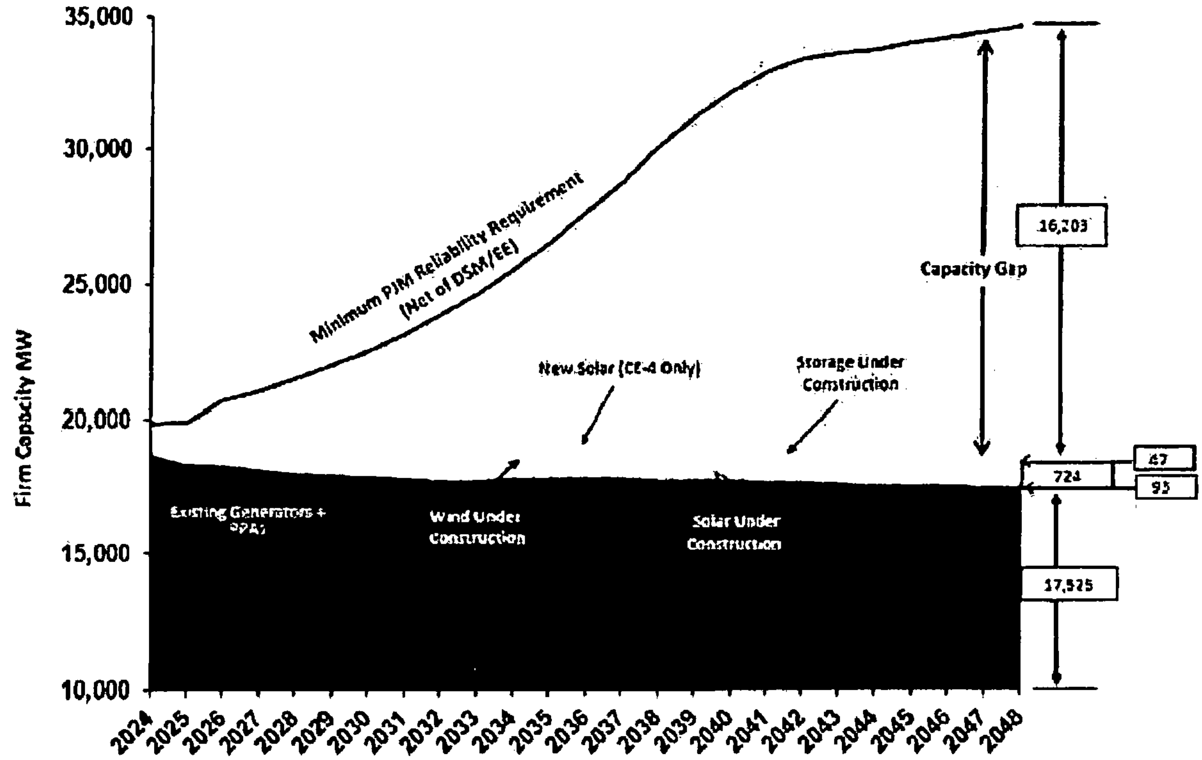
generation, ARB[525] load, and 100 MW customer load.[526] In other words, the red line in the chart shown above would have been higher without these offsets. **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][527] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

The CE-4 Projects can also help Dominion satisfy its capacity obligations. But it is important to understand that PJM – the entity that calculates Dominion's capacity obligation and capacity values – does not value intermittent solar capacity at the nameplate value.[528] Based on forecasted values from PJM, Dominion expects the collective 329 MW of nameplate capacity for the utility-scale CE-4 Projects would equate to a capacity value of only **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]** in 2027.[529] Based on degradation and changing capacity values, Dominion also expects the capacity value of the CE-4 Projects would decrease over time. By 2048, Dominion expects an undegraded capacity value of 47 MW and a degraded capacity value of 42 MW for these CE-4 Projects.[530] The undegraded 47 MW projected value is shown on the right-hand side of the following chart Dominion provided to illustrate the effect of the CE-4 Projects on Dominion's projected capacity position.[531]

---

[525] As discussed in this Report's Summary of the Record, the acronym "ARB" refers to the term "accelerated renewable energy buyer," which is defined in Code § 56-585.5.
[526] Tr. at 155 (Morton); Ex. 4 (2023 RPS Development Plan) at Attachment 8. A digit is missing from the nuclear generation figure for 2021, which was presumably an inadvertent omission.
[527] Tr. Day 1 ES Session 4 at 6-8 (Gaskill). As discussed above in Section I of this Report's Analysis, Dominion's 2023 RPS Development Plan uses certified ARB capacity to offset the 2035 statutory petition requirements, although Appalachian Voices recognizes that this approach did not offset any of the interim statutory petition requirements.
[528] *See, e.g., PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056, Order Accepting Tariff Revisions and Terminating Section 206 Proceeding (July 30, 2021).
[529] Exs. 21, 21-ES. Dominion made an adjustment to PJM's value for 2027. *Id.*
[530] *Id.* Staff noted disagreement with Dominion's projected effective load carrying capability capacity values used to model solar resources. Ex. 37 (Brunelle) at 20. However, Staff and Dominion litigated that issue in the 2023 IRP Case, rather than the instant proceeding. This Report's Analysis uses the effective load carrying capability capacity values Dominion provided in the record of the instant case.
[531] Ex. 20 (Morton direct) at 7; Tr. at 385-86 (Morton).

Company Capacity Position With CE-4 (2024 to 2048)



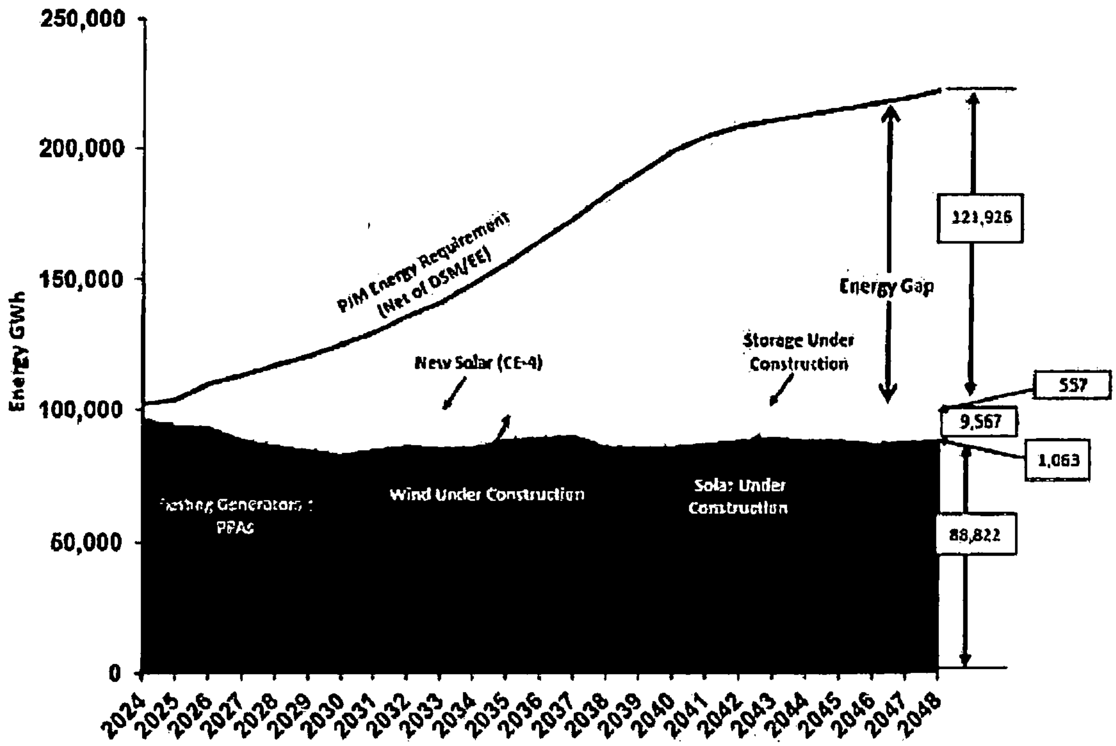
Notes: "PPAs" = power purchase agreements or contracted-for resources; "DSM" = demand side management; "EE" = energy efficiency.

As illustrated above, the capacity contribution of the CE-4 Projects (like their REC contribution) is modest compared to Dominion's projected obligation. However, the VCEA directs Dominion to retire its fossil-generation fleet, absent a reliability threat, pursuant to a statutory schedule[532] and those resources currently provide a significant amount of capacity. Notably, many large, existing fossil generation facilities that the VCEA schedules for retirement (absent a reliability threat) during the expected 35-year lives of the CE-4 Projects are assumed to remain operational in Dominion's above chart.[533] As calculated by Staff, the 2048 "Capacity Gap" illustrated as 16,203 MW in the above figure increases to 27,620 MW if all the Company's carbon-emitting generation is assumed to retire by the end of 2045 (consistent with Dominion's IRP Alternative Plans D and E).[534]

[532] Code § 56-585.5 B.
[533] Mr. Morton indicates his chart reflects the retirement assumptions of IRP Alternative Plan B, which preserves existing generation through this period. Ex. 20 (Morton direct) at 6; Ex. 4 (2023 RPS Development Plan) at 12.
[534] Ex. 37 (Brunelle) at 11.

Turning to Dominion's assertion of an energy need for the utility-scale CE-4 Projects, they are initially expected to collectively contribute approximately 622 GWh of energy annually.[535] Dominion expects energy production will decrease over time, with its chart below showing approximately 557 GWh of projected energy from these projects in 2048.[536]

Current Company Energy Position With CE-4 (2024 to 2048)



Notes: "PPAs" = power purchase agreement or contracted-for resources; "DSM" = demand side management; "EE" = energy efficiency.

Like the preceding capacity chart, the above energy chart preserves existing generation that the VCEA schedules for retirement.[537] As calculated by Staff, the 2048 "Energy Gap" illustrated as 121,926 GWh in the above chart increases to 182,049 GWh if all the Company's carbon-emitting generation is assumed to retire by the end of 2045 (consistent with Dominion's IRP Alternative Plans D and E).[538]

Dominion recognized, with some important caveats, that market purchases can narrow the projected "Capacity Gap" and "Energy Gap" illustrated in the above figures. Company witness Morton testified as follows:

---

[535] Ex. 21.
[536] Ex. 20 (Morton direct) at 8. *See also* Ex. 21.
[537] Ex. 20 (Morton direct) at 6.
[538] Ex. 37 (Brunelle) at 14.

> Market purchases are an option to help close the energy and capacity gap, but because of the Company's responsibility for system reliability, I do not recommend an overreliance on market purchases. There are limits to the amount of capacity and energy the Company can purchase and physically receive. There is also a risk that as other states retire dispatchable generation and bring more renewable energy online, the amount of capacity and energy available for purchase – especially during the winter – may decrease.[539]

I find the VCEA created a need for the proposed CE-4 Projects, which would provide RECs that are necessary for RPS compliance, in addition to capacity and energy. The evidence in the record supports a finding that there are large Company needs for RPS compliance, capacity, and/or energy. The increases (since the 2023 RPS Plan Case) in the REC, energy, and capacity "gaps" – although based on assumptions, some of which are not beyond critique – are notable, and potentially concerning. Dominion's unprecedented load and peak load growth projections, attributed to additional data center growth, increase the challenges of transforming Dominion's generation fleet without compromising system reliability or affordability. Based on the most conservative peak load forecast presented in this case – prepared by Staff witness Johnson – Dominion's capacity obligation is projected to increase by approximately 7,600 MW by 2038, while Dominion projects its capacity obligation will increase by approximately 14,700 MW by 2038.[540] The amount of fossil-fuel generation that the VCEA schedules for retirement, absent a reliability problem, by 2045 totals approximately 10,000 MW.[541] The fact that the 329 MW of nameplate capacity for the utility-scale CE-4 Projects, at an estimated capital cost of $839 million, equates to an undegraded projected capacity value of only **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]** in 2027 and degraded capacity value of only 42 MW by 2048 puts the challenges of significant load growth or significant retirements in perspective.[542]

Having found the record demonstrates a need, as discussed above, whether the public convenience and necessity require the CE-4 Projects to satisfy the identified need(s) is discussed below. Such a determination is informed by, among other things, considerations of costs and benefits, environmental impact, and economic development, as discussed below.

---

[539] Ex. 49 (Morton rebuttal) at 5.

[540] *See, e.g.*, Ex. 40 (Glattfelder) at rev. 25; Ex. 39 (Johnson) at Attached Report, p. 18. PJM capacity obligations for Dominion are set using an installed reserve margin above forecasted peak load. *See, e.g.*, *LS Power Development, LLC et al. v. PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,021 at P. 2, n. 4, Order Denying Complaint (July 16, 2021).

[541] *See, e.g.*, Ex. 40 (Glattfelder) at 29, Attachment MSG-3, p. 3. However, I do not find persuasive the Company's suggestion that the CE-4 Projects and PPAs represent the quickest way for Dominion to address any immediate need caused by 2023 retirements of Chesterfield Units 5 and 6, and Yorktown Unit 3. Tr. at 391 (Morton). Were Dominion's plan to replace 1,800 MW of 2023 retirements with the CE-4 resources, which have a total capacity that is a fraction of that amount, and most of which would not be operational until 2026-2027, such a plan could be considered too little, too late.

[542] Exs. 21, 21-ES. The basis for Dominion's designation of projected 2027 ELCC percentages as extraordinarily sensitive is unclear and may warrant inquiry in future Commission proceedings.

Cost and Economic Analysis for Beldale, Blue Ridge, Bookers Mill, and Michaux

The Commission has recognized that the "the VCEA does not require the Commission to approve cost recovery for all new projects *at any cost*."[543] The table below summarizes most of the Company's cost and economic evidence on the CE-4 Projects.[544]

CE-4 Project	Capital Cost	Levelized Cost of Energy (Dollars per Megawatt-Hour)		Net Present Value for Dominion's System Based on Modeling Runs Plus Three Different Values of Avoided REC Cost (Millions)			Net Present Value for the World From Reduced Carbon Emissions (Millions)
Beldale 57 MW	$158 million	RECs	No RECs	1	2	3	$40
	$2,766/kW	$85	$93	($14)	($66)	($30)	
Blue Ridge 95 MW	$299 million	RECs	No RECs	1	2	3	$73
	$3,152/kW	$86	$94	($63)	($158)	($92)	
Bookers Mill 127 MW	$249 million	RECs	No RECs	1	2	3	$87
	$1,961/kW	$67	$79	$29	($77)	($4)	
Michaux 50 MW	$133 million	RECs	No RECs	1	2	3	$34
	$2,661/kW	$81	$89	($27)	($71)	($40)	
Portfolio 329 MW	$839 million $2,551/kW	$67-$94/MWh Range		($76)-($373) million Range			$234 million

As shown in the last row of the above table, Dominion's total estimated cost for the utility-scale CE-4 Projects is approximately $839 million, or $2,551/kW based on the nameplate capacity of these projects. Based on Dominion's estimated initial capacity value of these projects, this effectively equates to **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][545] **[END EXTRAORDINARILY SENSITIVE INFORMATION]** These projects have levelized costs of energy ranging from $67 to

[543] *2022 RPS Plan Order* at 9 (emphasis in original).

[544] *See, e.g.*, Ex. 11 (Flowers direct) at attached Sched. 4, p. 1, Sched. 5, revised p. 1, Sched. 6, revised p. 1, and Sched. 7, p. 1; Ex. 49 (Morton rebuttal) at 13; Ex. 22. Dominion also provided lower (worse) net present value figures for Blue Ridge using the Company's three-year average capacity factor, rather than the design capacity factor. *See, e.g.*, Ex. 22.

[545] **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

$94/MWh, depending on the project and whether RECs are included as a credit in the calculation. In Dominion's economic analysis to evaluate whether the projects are more or less economic than the market,[546] the portfolio has a negative net present value ranging between negative $76 million[547] and negative $373 million[548] – indicating the market modeled by Dominion would provide a better economic result for Dominion's ratepayers.[549] The column on the far right of the above table shows Dominion's attempt to quantify the benefit to society that the facilities would provide by displacing generation with carbon emissions, an estimated global net present value benefit of $234 million for the portfolio.

The manner in which Dominion presented its social cost of carbon estimates warrants further discussion. Last year, Dominion embedded its estimates of the net present value of the social cost of carbon benefit in the CE-3 Project results it showed. The *2022 RPS Plan Order* directed Dominion "to separate, in its economic analysis, any estimated social cost of carbon cost/benefit from the estimated ratepayer benefits and costs."[550] The Petition in the instant case separated the global social cost of carbon benefit, but then added it back with the net present value results applicable to Dominion's system. Below is an example of Dominion's presentation of this information in the instant case.[551]

Project Name	Project Type	Solar MW	NPV without SCoC $000	NPV of ScoC $000	NPV $000
Beldale	Utility Scale Solar	57	(29,643)	39,865	10,222

A reader could reasonably assume that the above figures show Dominion's economic analysis indicates that Beldale is economic for Dominion's ratepayers. That is not what these figures show. The negative $29.6 million figure is an estimate of the *detriment to Dominion's ratepayers* from constructing and operating Beldale instead of pursuing market alternatives. The positive $39.9 million figure is an estimate of the *benefit to the entire world* from the estimated carbon reductions that Beldale could achieve.[552] When these two figures are added together – as Dominion's table does in its far right column – the combined figure is confusing, at best, because its components measure two different things on two drastically different scales.[553] The social cost

[546] Tr. at 153-54 (Morton).
[547] Scenario 1 values the avoided cost of RECs at the statutory deficiency penalty.
[548] Scenario 3 values the avoided cost of RECs at Dominion's forecasted price for RECs.
[549] Dominion's modeling runs are total system numbers based on modeling runs for its load serving entity under a cost-of-service methodology. Tr. at 411 (Morton); Ex. 20 (Morton direct) at 11. As a cost-of-service utility, Dominion's customers pay for the costs of its system. To its modeling results, Dominion adds an avoided cost of RECs to arrive at the "NPV without SCoC" amount. The avoided cost of RECs, which are priced differently in Dominion's three scenarios, estimate a cost that Dominion's customers would otherwise pay.
[550] *2022 RPS Plan Order* at 10.
[551] Ex. 22 (excerpt).
[552] For each project, Dominion calculates its social cost of carbon benefit estimate by putting a value on estimated emissions that solar generation would displace. The value used in Dominion's calculations is the federal government's $51/ton. *See, e.g.*, Tr. at 157 (Morton) (describing the calculation). The $51 amount is an estimate of the global harm caused by each metric ton of carbon dioxide emitted. *See, e.g.*, Ex. 50 at 14-16; Tr. at 386 (Morton).
[553] That the Code requires the Commission to consider the social cost of carbon, as a cost or a benefit, does not mean the Commission must add an estimate of such a benefit to other figures. The Code directs the Commission to consider a number of things in this case – qualitative and quantitative (*e.g.*, economic development benefits) – that are not added to figures intended to estimate costs or benefits to ratepayers.

of carbon benefit does not directly benefit ratepayers, and encompasses a group far broader than Dominion's ratepayers. This global benefit, if quantified,[554] should be separated – as directed by the *2022 RPS Plan Order* and presented in my summary table above – from the figures that are specific to Dominion's system.

Environmental Impact

The Commission's evaluation of a requested CPCN must "give consideration to the effect of that facility on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact."[555] While Code §§ 56-580 D and 56-46.1 A direct the Commission to consider the environmental impact of proposed facilities, anti-duplication provisions in these statutes also indicate that:

> any valid permit or approval required for an electric generating plant and associated facilities issued or granted by a federal, state or local governmental entity charged by law with responsibility for issuing permits or approvals regulating environmental impact and mitigation of adverse environmental impact or for other specific public interest issues ..., whether such permit or approval is prior to or after the Commission's decision, shall be deemed to satisfy the requirements of this section with respect to all matters that (i) are governed by the permit or approval or (ii) are within the authority of, and were considered by, the governmental entity in issuing such permit or approval, and the Commission shall impose no additional conditions with respect to such matters....

Dominion asserts that the Commission is not required to consider the environmental impact of Bookers Mill due to these "anti-duplication" provisions of the Code. This Report addresses this assertion before analyzing the environmental impact of the other three solar facilities for which Dominion seeks a CPCN.[556]

Bookers Mill's Permit by Rule and Prior Environmental Approvals

In 2021, Dominion was developing Bookers Mill for a specific customer, and not as a facility that would be used to supply the Company's jurisdictional customers. At that time, Dominion obtained a DEQ permit by rule for the facility, along with Clean Water Act permits from the U.S. Army Corps of Engineers and DEQ.[557]

---

[554] Consumer Counsel asserted that the social cost of carbon lends itself to consideration as an additional qualitative factor. Tr. at 562-63 (Farmer). In my opinion, the Commission has broad discretion to determine how the social cost of carbon benefit estimates will be considered in this case. That the Code contemplates the social cost of carbon used by the Commission would be adjusted for inflation suggests that such consideration may be quantitative, in my view. *See* Code § 56-585.1 A 6 ("The Commission shall include a system to adjust the costs established in this section with inflation.").

[555] Code § 56-46.1 A. *See also* Code § 56-580 D.

[556] Ex. 11 (Flowers direct) at attached Sched. 6, p. 4.

[557] *Id.* at 18 and attached Sched. 6, p. 4.

Dominion's plan for Bookers Mill changed after its intended customer no longer wanted to pursue this project.[558] The Petition now seeks a CPCN for the facility so that it can be used for, and its costs recovered from, the Company's jurisdictional customers. Given the prior approvals obtained for Bookers Mill and the statutory anti-duplication provisions shown above, Dominion asserts that the Commission is not required to consider the facility's environmental impact.[559]

Since their enactment, the DEQ permit by rule statutes for "small" renewable generation projects have treated rate-regulated public utilities like Dominion different than independent developers who are not rate-regulated by the Commission. Independent developers could choose to obtain a permit by rule in lieu of a Commission CPCN. In contrast, a Commission CPCN initially remained a requirement for all small renewable projects proposed by Dominion. For Dominion, a DEQ permit by rule, however, negated the Commission's environmental review during a CPCN proceeding for a small renewable project.[560]

In 2017, the General Assembly decided that rate-regulated utilities like Dominion should also have the choice to pursue a permit by rule in lieu of a CPCN for one situation. If the costs of a small renewable facility were not recovered from Virginia jurisdictional customers through retail rates, Dominion could now obtain a permit by rule and forego a CPCN review for such a facility.[561]

As discussed above, Dominion obtained a permit by rule for Bookers Mill but did not seek a CPCN from the Commission in 2021, or before commencing construction.[562] Such action was consistent with the Code, as amended in 2017, because the project was initially developed for a specific customer without retail rate recovery from Virginia jurisdictional customers intended by the Company.[563]

A plain reading of Code §§ 56-580 D and 56-46.1 suggests that the Commission may not consider the environmental impact of Bookers Mill because the DEQ permit by rule was approved for this project. The permit by rule obtained by Dominion for Bookers Mill is a comprehensive authorization[564] that therefore is inclusive of "environmental impact and mitigation of adverse environmental impact or for other specific public interest issues."[565] The permit by rule therefore appears to leave no room for Commission consideration of environmental impacts under the anti-duplication provisions of Code §§ 56-580 D and 56-46.1.

---

[558] *See, e.g.,* Tr. at 108-09 (Flowers); Tr. Day 1 ES Session 1 at 13-14 (identifying the customer).
[559] Ex. 11 (Flowers direct) at attached Sched. 6, p. 4.
[560] *See* 2009 Va. Acts chs. 808, 854 (Code §§ 10.1-1197.8). As noted below, subsection B of Code § 10.1-1197.8 was subsequently amended.
[561] 2017 Va. Acts ch. 368 (adding Code § 10.1-1197.6 I and amending Code § 10.1-1197.8 B).
[562] Ex. 11 (Flowers direct) at 13.
[563] Ex. 24 (Boschen direct) at 3.
[564] *Id.* at attached Sched. 1 (providing the permit by rule).
[565] Code §§ 56-580 D and 56-46.1 A.

I also found instructive the current provisions of Code § 10.1-1197.8 B shown below.

> If the owner or operator of a small renewable energy project for which the [DEQ] has authorized a permit by rule pursuant to this article is a utility regulated pursuant to Title 56, such small renewable energy project shall be exempt from any provision of § 56-46.1 and any corresponding provision of subsection D of § 56-580 or Chapter 10.1 (§ 56-265.1 et seq.) of Title 56 that requires environmental review and permitting by the [Commission]. An owner or operator of a small renewable energy project that is granted a permit by rule pursuant to subsection I of § 10.1-1197.6, shall not be required to obtain a [CPCN] pursuant to subsection D of § 56-580 or the Utility Facilities Act (§ 56-265.1 et seq.)....

The above statutory language recognizes that Dominion can obtain a permit by rule for a small renewable project, regardless of cost recovery.[566] As shown in the first sentence, if project costs *are recovered* through Virginia jurisdictional retail rates, a permit by rule obtained by Dominion only negates the Commission's environmental review in a CPCN proceeding. As shown in the second sentence, the permit by rule under Subsection I of § 10.1-1197.6 – available to Dominion if project costs *are not recovered* through such rates[567] – negates the need for a CPCN entirely. In my view, Bookers Mill's proposed change in cost recovery, if approved by the Commission, moves the project from the second sentence of Code § 10.1-1197.8 B to the first sentence. Accordingly, based on my reading, the environmental requirements of the permit by rule would remain in effect for Bookers Mill and the project is "exempt from any provision of § 56-46.1 and any corresponding provision of subsection D of § 56-580 or Chapter 10.1 (§ 56-265.1 et seq.) of Title 56 that requires environmental review and permitting by the ... Commission."[568]

Dominion represented that it will continue to adhere to all commitments associated with the existing permit by rule for Bookers Mill.[569] In my view, such commitments appear to remain legal requirements, enforceable by DEQ. The CPCN, if granted, would become the Commonwealth's regulatory authorization for Dominion to own, construct, and operate Bookers Mill, while the permit by rule effectively becomes an environmental permit. In other words, the Commission's and DEQ's regulatory authority over Bookers Mill would reflect the same complimentary nature governing most of Dominion's generation facilities in the Commonwealth.

For the foregoing reasons, I conclude that environmental review of the Bookers Mill solar facility in this proceeding is prohibited by the anti-duplication provisions of Code §§ 56-580 D and 56-46.1 A and/or exempted from such review by Code § 10.1-1197.8 B.[570] However, pursuant to Code §§ 56-580 D and 56-46.1 A, the Commission must consider the environmental impacts of Beldale, Blue Ridge, and Michaux, which are discussed below.

---

566 The first sentence applies to a "utility regulated under Title 56," which Dominion is. The second sentence references a permit by rule granted "pursuant to subsection I of § 10.1-1197.6," which is the avenue Dominion used to obtain the permit by rule for Bookers Mill before cost recovery through jurisdictional rates was contemplated.

567 Code § 10.1-1197.6 I 1.

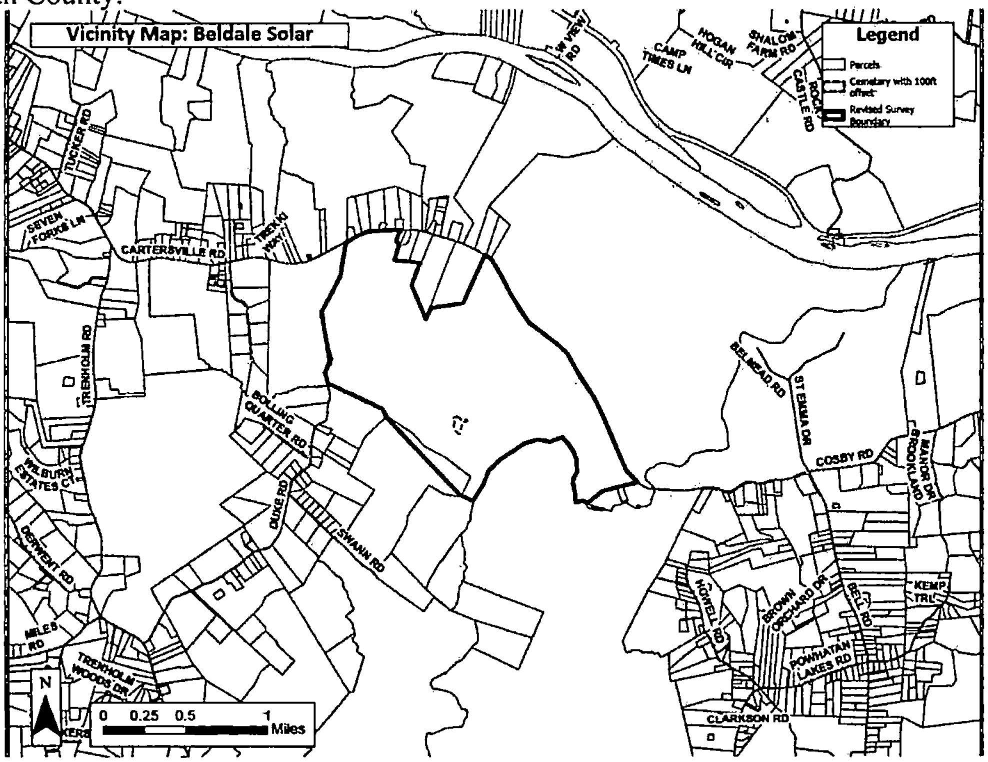
568 Code § 10.1-1197.8 B.

569 Ex. 24 (Boschen direct) at 3; Ex. 11 (Flowers direct) at attached Sched. 6, p. 4. The permit by rule is part of the record in the instant case. Ex. 24 (Boschen direct) at attached Sched. 1.

570 If the Commission disagrees with this conclusion, the Commission should consider initiating a wetlands consultation and coordinated review by DEQ for this project. Dominion's Petition did not include a DEQ Supplement for Bookers Mill and the DEQ Report did not include a consultation or review for this project.

Environmental Impact of Beldale

The vicinity map below[571] shows the location of the proposed Beldale solar project in Powhatan County.



The 323-acre site for Beldale is part of a parcel of land that includes undeveloped and forested areas in silviculture.[572] The existing 230 kV transmission line to which Beldale plans to interconnect bisects this property.[573]

According to DEQ, the Army Corps of Engineers issued a preliminary determination that this project contains 200 acres of palustrine forested wetlands; 0.38 acres of palustrine scrub-shrub wetlands; 21,498 linear feet of perennial stream channel; 2,281 linear feet of intermittent stream channel; and 11,237 linear feet of ephemeral stream channel – but there are no impacts based on the current conceptual design.[574]

According to DOF, approximately 321 acres, almost all of which is forested or recently harvested timberlands, are at risk of conversion with the Beldale solar project. A large portion of the forested acreage within the project boundaries is identified as high forest conservation value, although much of this forested acreage consists of pine stands that have been managed for timber

---

[571] Ex. 11 (Flowers direct) at attached Sched. 4, p. 12.

[572] Ex. 24 (Boschen direct) at attached DEQ Supplement for Beldale, p. 6; Ex. 11 (Flowers direct) at attached Sched. 4, p. 10.

[573] Ex. 11 (Flowers direct) at attached Sched. 4, pp. 3, 14. The existing line is Line #2027 (Bremo – Powhatan). Ex. 12 at Beldale Interconnection Service Agreement, p. 12 (bottom right corner).

[574] Ex. 42 (DEQ Report) at 9.

production.[575] The project would impact ecological cores rated C2 and C4 (on a scale of C1 to C5 in which C5 is the least ecologically relevant).[576]

DHR indicated that Dominion's proposal for Beldale, consistent with prior consultation, would avoid a potentially eligible archaeological site and an unmarked cemetery.[577] The James River, which qualifies for scenic river designation and is designated as a "water trail," is located one mile north of the project.[578]

According to available information, the endangered (federal and state) northern long-eared bat and the proposed endangered tri-colored bat have the potential to occur on the project site, although there are no known maternity roosts or hibernacula for the former located within 5.5 miles of the project. Nor are there any known winter habitat or roosts for the little brown bat or tri-colored bat within 5.5 miles of the project site. Dominion would adhere to federal regulation governing northern long-eared bats, coordinate with the U.S. Fish and Wildlife Service ("USFWS") as needed, and review DWR's best management practices for conservation of tri-colored bats.[579]

The Deep Creek Stream Conservation Unit is located within the project area and has a biodiversity rank of B4 (moderate significance).[580] Deep Creek is a potential habitat for two threatened freshwater mussels, the Atlantic pigtoe and green floater, in the project area. However, the Project does not propose any work on Deep Creek[581] and a DCR zoologist found the occurrence of the Atlantic pigtoe within the project boundary is unlikely.[582]

Dominion identified three VOF easements in the area, two of which are located across Cartersville Road from the project site.[583] VOF indicated that the project would not encroach on any existing or proposed VOF open-space easements.[584]

While Consumer Counsel indicated that the social cost of carbon benefit should be considered as a qualitative (not quantitative) benefit, no case participant questioned Dominion's assumption that Beldale would reduce air emissions by displacing fossil-fired energy production.[585] In addition, Beldale's energy production would require minimal water use.[586]

Powhatan County has granted Beldale a conditional use permit, which addresses, among other things: setbacks; buffers, including riparian buffers along streams and wetlands; the

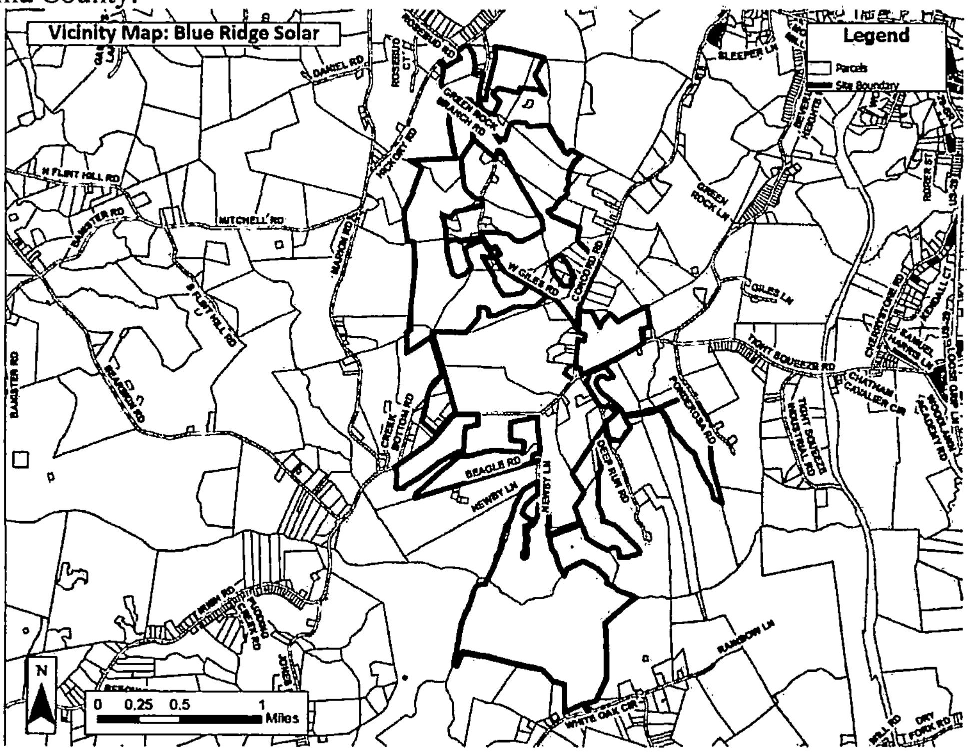
---

[575] *Id.* at 23-24.
[576] *See, e.g., id.* at 20.
[577] *Id.* at 31.
[578] Ex. 24 (Boschen direct) at attached DEQ Supplement for Beldale, pp. 10-11.
[579] *Id.* at attached DEQ Supplement for Beldale, pp. 6-8.
[580] Ex. 42 (DEQ Report) at 18.
[581] Ex. 24 (Boschen direct) at attached DEQ Supplement for Beldale, p. 7.
[582] Ex. 42 (DEQ Report) at 19. Potential habitat for the Atlantic pigtoe may occur further downstream. *Id.*
[583] Ex. 24 (Boschen direct) at attached DEQ Supplement for Beldale, p. 11. These easements are located 0.1, 0.2, and 1.1 miles north of the project. *Id.*
[584] Ex. 42 (DEQ Report) at 30.
[585] *See, e.g.,* Ex. 24 (Boschen direct) at attached DEQ Supplement for Beldale, pp. 2-3.
[586] *Id.* at 3.

planting and management of vegetation; construction traffic management; erosion and sediment control; stormwater management; and decommissioning.[587]

Environmental Impact of Blue Ridge

The vicinity map below[588] shows the location of the proposed Blue Ridge solar project in Pittsylvania County.



The 1,455-acre site for Blue Ridge is part of a parcel of land that includes agricultural fields, pasture, forest and recently cleared timberlands.[589]

According to DEQ, the Army Corps of Engineers issued a preliminary determination that this project contains 194.66 acres of wetlands; 75,504 linear feet of stream channel; and 22.27 acres of surface waters.[590] One crossing, for an access road, is expected to impact 0.1 to 0.2 acres of wetlands and 50-60 linear feet of stream.[591]

According to DOF, a large portion of the forested acreage within the project's boundaries is identified as high forest conservation value, although much of this forested acreage consists of pine stands which have been managed for timber production.[592] The project would impact

[587] Ex. 13 at Powhatan Conditional Use Permit Ordinance O-2022-21.
[588] Ex. 11 (Flowers direct) at attached Sched. 5, p. 16.
[589] Ex. 42 (DEQ Report) at 2; Ex. 11 (Flowers direct) at attached Sched. 5, p. 14.
[590] Ex. 42 (DEQ Report) at 9.
[591] Ex. 24 (Boschen direct) at attached DEQ Supplement for Blue Ridge, p. 4; Ex. 42 (DEQ Report) at 9.
[592] Ex. 42 (DEQ Report) at 24.

ecological cores rated C4 and C5 (on a scale of C1 to C5 in which C5 is the least ecologically relevant).[593]

DHR indicated that Dominion's proposal for Blue Ridge, consistent with prior consultation, would not adversely impact four eligible or potentially eligible architectural resources, subject to a screening condition. Dominion would coordinate with DHR on the landscape buffers for these properties.[594] A portion of the Banister River that is designated as a scenic river is located 1.5 miles east of the project.[595]

No natural heritage resources have been documented within the site.[596] However, Dominion would continue to coordinate with USFWS, DWR, and DCR as needed regarding the management and protection of species within the site.[597] According to available information, the endangered (federal and state) northern long-eared bat and the proposed endangered tri-colored bat have the potential to occur on the project site, although there are no known maternity roosts or hibernacula for the former located within 5.5 miles of the project. Nor are there any known winter habitat or roosts for the little brown bat or tri-colored bat within 5.5 miles of the project site. Dominion would adhere to federal regulation governing northern long-eared bats, coordinate with USFWS as needed, and review DWR's best management practices for conservation of tri-colored bats.[598]

One conservation easement is located 1.2 miles east of the project.[599] VOF indicated that the project would not encroach on any existing or proposed VOF open-space easements.[600]

While Consumer Counsel indicated that the social cost of carbon benefit should be considered as a qualitative (not quantitative) benefit, no case participant questioned Dominion's assumption that Blue Ridge would reduce air emissions by displacing fossil-fired energy production.[601] In addition, Blue Ridge's energy production would require minimal water use.[602]

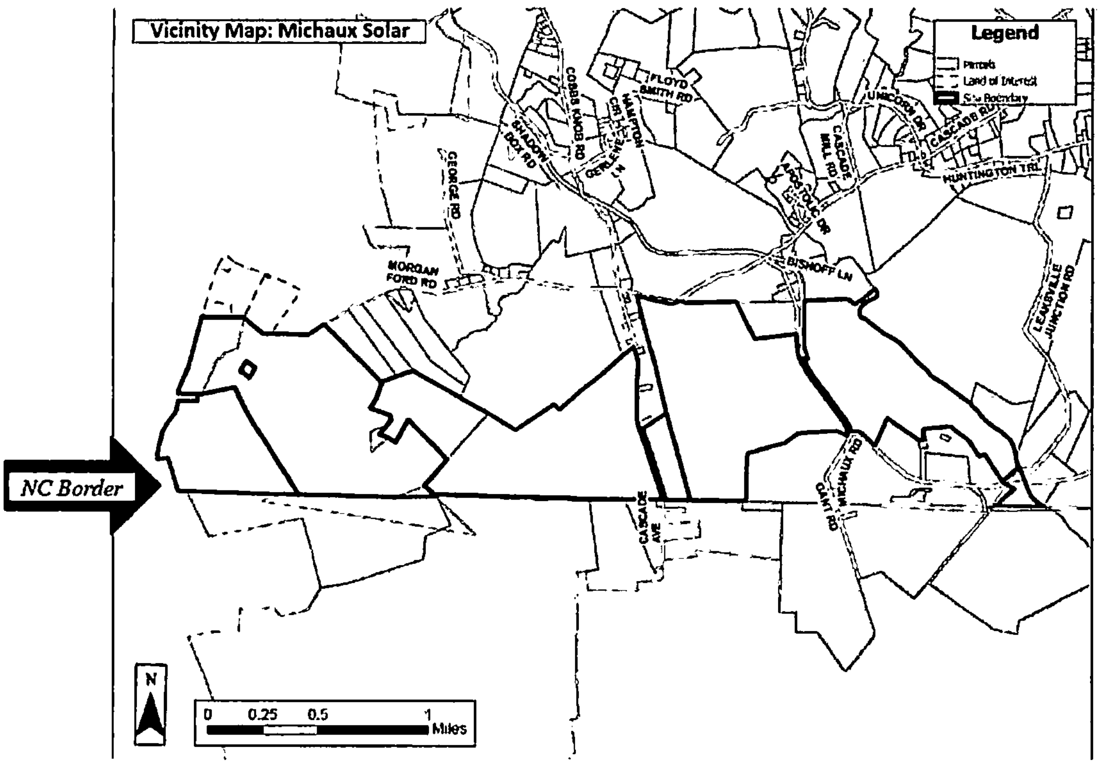
Pittsylvania County has granted Blue Ridge a special use permit, which addresses, among other things: setbacks, landscaping, erosion and sediment control, stormwater management, and decommissioning.[603]

---

[593] *See, e.g., id.* at 20.
[594] *Id.* at 31; Ex. 24 (Boschen direct) at attached DEQ Supplement for Blue Ridge, p. 10.
[595] Ex. 24 (Boschen direct) at attached DEQ Supplement for Blue Ridge, p. 10. A portion of the Banister River that does not have a scenic river designation traverses the project site. *Id.*
[596] *Id.* at attached DEQ Supplement for Blue Ridge, p. 7.
[597] *Id.* at attached DEQ Supplement for Blue Ridge, p. 8.
[598] *Id.* at attached DEQ Supplement for Blue Ridge, p. 7.
[599] *Id.* at attached DEQ Supplement for Blue Ridge, p. 11; Ex. 42 (DEQ Report) at 20.
[600] Ex. 42 (DEQ Report) at 30.
[601] *See, e.g.*, Ex. 24 (Boschen direct) at attached DEQ Supplement for Blue Ridge, pp. 2-3.
[602] *Id.* at 3.
[603] Ex. 13 at Pittsylvania County Board of Zoning Appeals Final Order S-20-009.

Environmental Impact of Michaux

The vicinity map below[604] shows the location of the proposed Michaux solar project in Henry and Pittsylvania Counties, with an arrow added to identify the border between the Commonwealth and North Carolina.



The 1,352-acre site for Michaux is part of a parcel of land that is primarily wooded and vegetated with dirt and access roads, timbered areas, an overhead transmission line right-of-way, agricultural fields and structures.[605]

According to DEQ, the Army Corps of Engineers issued a preliminary determination that this project contains 116 acres of wetlands and 108,439 linear feet of stream channel.[606] Dominion expects up to five stream crossings, for access road construction, would potentially impact a total of 300 linear feet of stream channel.[607] According to DOF, approximately 1,381 acres, much of which is forested or recently harvested timberlands, are at risk of conversion with the Michaux solar project. A portion of the forested acreage within the project boundaries is identified as high forest conservation value.[608] The project would impact ecological cores rated C3, C4, and C5 (on a scale of C1 to C5 in which C5 is the least ecologically relevant).[609]

---

[604] Ex. 11 (Flowers direct) at attached Sched. 7, p. 29.
[605] Ex. 42 (DEQ Report) at 2; Ex. 11 (Flowers direct) at attached Sched. 7, p. 27.
[606] Ex. 42 (DEQ Report) at 9.
[607] Ex. 24 (Boschen direct) at attached DEQ Supplement for Michaux, p. 4; Ex. 42 (DEQ Report) at 9.
[608] Ex. 42 (DEQ Report) at 24.
[609] *See, e.g., id.* at 20.

For archaeological resources within the project area, Dominion has agreed to an avoidance and mitigation plan that DHR has determined is appropriate. For one plantation property, Dominion completed a survey that DHR found to satisfy mitigation requirements for moderate adverse impacts.[610] The Smith River, a "potential scenic river," is located 1.0 mile west of the project.[611]

According to available information, the endangered (federal) Roanoke logperch and James spinymussel have the potential to occur on the project site. Dominion awaits a response from USFWS about the Company's request for a no effect concurrence in relation to project activities.[612] No known winter habitat or roosts for the little brown bat or tri-colored bat are within 5.5 miles of the project site. Dominion would review DWR's best management practices for conservation of tri-colored bats.[613]

The project area includes the State Line Tributary Conservation Site, which has a biodiversity significance ranking of B3 (high significance), due to the following natural heritage resources of concern: the Southern Piedmont Hardpan Forest, Carolina shagbark hickory, black-footed quillwort, and Southeastern stiff goldenrod.[614]

No conservation easements have been identified within two miles of the project.[615] VOF indicated that the project would not encroach on any existing or proposed VOF open-space easements.[616]

While Consumer Counsel indicated that the social cost of carbon benefit should be considered as a qualitative (not quantitative) benefit, no case participant questioned Dominion's assumption that Michaux would reduce air emissions by displacing fossil-fired energy production.[617] In addition, Michaux's energy production would require minimal water use.[618]

Pittsylvania County has granted Michaux a special use permit, which addresses, among other things: setbacks, landscaping, erosion and sediment control, stormwater management, and decommissioning.[619] Henry County has also approved a special use permit for Michaux,[620] which requires compliance with local ordinances addressing, among other things, visual impacts, setbacks, vegetative buffer, pollinator habitats, and decommissioning.[621]

---

[610] Ex. 42 (DEQ Report) at 31; Ex. 24 (Boschen direct) at attached DEQ Supplement for Michaux, pp. 10-11.
[611] Ex. 24 (Boschen direct) at attached DEQ Supplement for Michaux, p. 11.
[612] *Id.* at attached DEQ Supplement for Michaux, p. 6.
[613] *Id.* at attached DEQ Supplement for Michaux, p. 8.
[614] *Id.* at attached DEQ Supplement for Michaux, pp. 6-7.
[615] *Id.* at attached DEQ Supplement for Michaux, p. 12.
[616] Ex. 42 (DEQ Report) at 30.
[617] *See, e.g.*, Ex. 24 (Boschen direct) at attached DEQ Supplement for Michaux, pp. 2-3.
[618] *Id.* at 3.
[619] Ex. 13 at Pittsylvania County Board of Zoning Appeals Final Order S-21-001.
[620] *Id.* at Application for special use permit, with certification and approval by the Henry County Board of Zoning Appeals.
[621] Henry County Ordinances 21-1801 through 21-1808.

242330001

DEQ Report Recommendations

In CPCN proceedings, the Commission must "receive and give consideration to all reports that relate to the proposed facility by state agencies concerned with environmental protection."[622] The DEQ Report on Beldale, Blue Ridge, and Michaux, which provided some of the site-specific information discussed above, was received into the record.[623] While Dominion agreed with most of the recommendations in the DEQ Report, the Company disagreed with six recommendations discussed below.

First, Dominion recommended denial of DCR's recommendation for the Company to plant Virginia native pollinator plant species. Dominion asserted that this recommendation is potentially costly, inappropriate without further study, and unnecessary.[624] Dominion represented that it will comply with localities' requirements regarding the planting of pollinators.[625]

The *2021 RPS Plan Order* rejected a similar Virginia pollinator recommendation, finding that "[b]ased on the Company's representation that it will comply with any requirements adopted by localities addressing the planting of pollinators, we will not require the Company's compliance with this DCR recommendation."[626] The *2022 RPS Plan Order* also rejected similar recommendations, without elaboration.[627]

I do not recommend approval of this DCR recommendation, based on cost and legal concerns. Given the already challenging economics of the CE-4 Projects from a ratepayer perspective, as discussed above, I do not recommend potentially increasing the costs of these projects to ratepayers through the adoption of this recommendation. As a legal matter, the record in the instant case suggests that Commission adoption of this pollinator recommendation could be problematic under the anti-duplication provisions of Code §§ 56-580 D and 56-46.1 A. The conditional use permit for Beldale has specific terms addressing the planting of appropriate pollinator-friendly species in substantial conformance with a specified Vegetation Management Plan.[628] Among the issues considered by Pittsylvania County when issuing the special use permit for Blue Ridge was a landscape plan that was developed in consultation with DCR's Virginia Pollinator-Smart Solar Comprehensive Manual Version 1.0 (December 2019).[629] The Pittsylvania County special use permit for Michaux requires adherence to a landscape maintenance plan that will be approved by the local zoning administrator,[630] while the Henry County special use permit for the same project requires compliance with local ordinances[631] that

---

[622] Code § 56-46.1.
[623] Ex. 42 (DEQ Report).
[624] Ex. 45 (Boschen rebuttal) at 6-8.
[625] *Id.* at 6.
[626] *2021 RPS Plan Order*, 2022 S.C.C. Ann. Rep. at 320.
[627] *2022 RPS Plan Order* at 8-9 (making CPCN approval subject to, as relevant, compliance with only the uncontested recommendations of the DEQ Report).
[628] Ex. 13 at Beldale conditional use permit, p. 4.
[629] *Id.* at Blue Ridge conceptual site plan, unmarked pp. 28-30.
[630] *Id.* at Michaux - Pittsylvania special use permit, p. 2.
[631] *Id.* at Michaux - Henry County special use permit, p. 1 (requiring compliance with Henry County Ordinances 21-1801 through 21-1808).

address, among other things, pollinator habitats.[632] To the extent a locality considers such matters, that resulting local approval "shall be deemed to satisfy the requirements of"[633] Code §§ 56-580 D and 56-46.1 A with respect to those matters.

Second, Dominion recommended denial of DCR's recommendation for the Company to develop and implement an invasive species management plan. Dominion asserted that this recommendation is unnecessary and costly.[634] The *2021 RPS Plan Order* rejected a similar invasive species management plan recommendation, finding that "the Company should not be required to develop and implement an invasive species management plan specific to the CE-2 Project sites that is different from the Company's existing comprehensive integrated vegetation management plan for controlling vegetation, including invasive species, throughout the Company's service territory."[635] The *2022 RPS Plan Order* also rejected a similar recommendation, without elaboration.[636]

I do not recommend approval of this DCR recommendation, based on cost and legal concerns. Given the already challenging economics of the CE-4 Projects from a ratepayer perspective, as discussed above, I do not recommend potentially increasing the costs of these projects to ratepayers through the adoption of this recommendation. As a legal matter, the record in the instant case suggests that Commission adoption of this invasive species recommendation could be problematic under the anti-duplication provisions of Code §§ 56-580 D and 56-46.1 A. The conditional use permit for Beldale has specific terms prohibiting vegetation types classified by DEQ or DCR as invasive at the time of planting.[637] The Pittsylvania County special use permits for Blue Ridge and Michaux require adherence to landscaping maintenance plans that will be approved by the local zoning administrator.[638] The Henry County special use permit requires compliance with local ordinances[639] that address, among other things, the use of non-invasive plant species in vegetative buffers and seeding to reduce invasive weed growth.[640] To the extent a locality considers such matters, that resulting local approval "shall be deemed to satisfy the requirements of"[641] Code §§ 56-580 D and 56-46.1 A with respect to those matters.

While approval of this DCR recommendation in a generation CPCN proceeding raises statutory anti-duplication concerns, I note that Commission orders in transmission CPCN cases have directed Dominion to meet with DCR regarding this issue. Such orders have also directed

[632] Henry County Ordinance 21-1806 (g).
[633] Code §§ 56-580 D and 56-46.1 A.
[634] Ex. 45 (Boschen rebuttal) at 4-5.
[635] *2021 RPS Plan Order*, 2022 S.C.C. Ann. Rep. at 320.
[636] *2022 RPS Plan Order* at 8-9 (making CPCN approval subject to, as relevant, compliance with only the uncontested recommendations of the DEQ Report).
[637] Ex. 13 at Beldale conditional use permit, p. 4.
[638] *Id.* at Pittsylvania County Board of Zoning Appeals Final Order S-20-009, Condition 5, and Final Order S-21-001, Condition 5.
[639] *Id.* at Michaux - Henry County special use permit, p. 1 (requiring compliance with Henry County Ordinances 21-1801 through 21-1808).
[640] Henry County Ordinance 21-1806 (f), (g).
[641] Code §§ 56-580 D and 56-46.1 A.

Dominion to report on the status of such meetings in future transmission CPCN proceedings.[642]

Third, Dominion recommended denial of DOF's recommendation to mitigate or compensate for negative impacts to trees or forests.[643] Dominion identified its efforts to minimize forest impacts as practicable in siting the CE-4 Projects. These efforts included identifying previously disturbed and cleared areas near the proposed interconnection location to the greatest extent feasible and designing projects in a manner that focuses on development within unconstrained lands while conserving, through avoidance, sensitive areas to the greatest extent possible. Dominion also indicated that in many cases forested areas on the site that are not impacted by construction will be designated as conserved open space under the facility's approved stormwater management plan.[644] Dominion argued that the costs of planting trees on open land generally or establishing open-space easements should not be borne by Dominion's customers.[645] The *2021 RPS Plan Order* rejected a similar recommendation by DOF as "unwarranted given the lack of a legal requirement for one-for-one mitigation."[646] The *2022 RPS Plan Order* also rejected a similar recommendation, without elaboration.[647]

I do not recommend approval of this DOF recommendation, based on the same rationale identified during the 2022 RPS Plan Case.[648] The scale of the VCEA's requirements for renewable generation produced in the Commonwealth will impact a significant amount of land, including forestland, in the Commonwealth. Given the already challenging economics of the CE-4 Projects from a ratepayer perspective, as discussed above, I do not recommend increasing the costs of these projects to ratepayers through the adoption of this DOF recommendation.

Fourth, Dominion opposed recommendations by DCR-DNH to increase the width of buffers along waterways. The Company asserted that it will comply with all state and local requirements related to buffering waterways and will implement a voluntary minimum buffer, making this recommendation unnecessary, duplicative, and unreasonable.[649] In my opinion, the local governments' consideration of riparian buffers in their special/conditional use permit processes leaves no room for Commission consideration of this issue, given the statutory anti-duplication provisions. Powhatan County's conditional use permit for Beldale specifically addresses, among other things, riparian buffers along streams and wetlands.[650] The site plan submitted during the Pittsylvania County special use permit process for Blue Ridge identifies

---

[642] *See, e.g., Application of Virginia Electric and Power Company, For approval and certification of electric transmission facilities: Butler Farm to Clover 230 kV Line, Butler Farm to Finneywood 230 kV Line and Related Projects*, Case No. PUR-2022-00175, Final Order at 17 (May 31, 2023) (citing a prior Commission directive in Case No. PUR-2021-00272).

[643] Ex. 42 (DEQ Report) at 24-25; Ex. 45 (Boschen rebuttal) at 12-14.

[644] Ex. 45 (Boschen rebuttal) at 13.

[645] *Id.* at 14.

[646] *2021 RPS Plan Order*, 2022 S.C.C. Ann. Rep. at 319.

[647] *2022 RPS Plan Order* at 8-9 (making CPCN approval subject to, as relevant, compliance with only the uncontested recommendations of the DEQ Report).

[648] *See* Ex. 45 (Boschen rebuttal) at 12-13 (identifying portions of the Hearing Examiner's Report in the 2022 RPS Plan Case).

[649] *Id.* at 3, 8-9.

[650] Ex. 13 at Powhatan Conditional Use Permit Ordinance O-2022-21, Condition 15.

wetland, stream, and surface water buffers.[651] The preliminary site plan for Michaux also appears to include wetland buffers.[652] To the extent a locality considers such matters, that resulting local approval "shall be deemed to satisfy the requirements of"[653] Code §§ 56-580 D and 56-46.1 A with respect to those matters.

Fifth, Dominion opposed a recommendation by DCR-DNH to conduct an inventory for Southern Piedmont Hardpan Forest, Carolina shagbark hickory, and Black-footed quillwort in the study area for Michaux in the spring and summer. The Company asserted that this recommendation is unnecessary and unreasonable. According to Dominion, Carolina shagbark hickory and Black-footed quillwort are not classified as threatened or endangered species and therefore are not protected by any regulations. Southern Piedmont Hardpan Forest, while considered rare by DCR-DNH, is not protected by any regulations. The Company indicated that a requirement to inventory for potential resources prior to construction would result in a significant delay to the construction schedule, potentially increasing project costs. Should the Commission not reject this recommendation, Dominion suggested that, as an alternative to conducting a pre-construction inventory, the Company could provide its construction team with information about these plant species and coordinate with DCR-DNH if a species of concern is observed within the Michaux project area.[654] I recommend Dominion's alternative suggestion, assuming it can be accomplished without delaying construction of the Michaux solar project.

Sixth, Dominion recommended that the Commission deny DCR-DNH's recommendation that the Company conduct a bat mist net survey to determine what bat species may be present in the Blue Ridge project area. As described by the Company, bat mist netting involves catching bats in a net to enable survey of bat populations in a specific area.[655] Dominion asserted that this recommendation is duplicative of survey work that has already been completed and would result in a significant delay to the construction schedule, potentially increasing project costs. Dominion pointed out that USFWS and DWR – the agencies with jurisdiction over these species – did not raise a concern over relying on an acoustic survey that has already been performed.[656] Dominion did not select Blue Ridge from the 2020 Solar-Wind-Storage RFP because the construction schedule for this project remained uncertain until the bat survey was completed.[657] I find that it is reasonable for Dominion to follow applicable guidance, and any requirements, of USFWS and DWR on this issue.

Furthermore, I find that the uncontested recommendations from the DEQ Report are desirable or necessary to minimize adverse environmental impact.

[651] *Id.* at Conceptual Site Plan, p. 2 (General Notes, fifth bullet) and pp. 6-19 (identifying buffers, including surface water buffers).
[652] Ex. 44.
[653] Code §§ 56-580 D and 56-46.1 A.
[654] Ex. 45 (Boschen rebuttal) at 10.
[655] *Id.* at 11.
[656] *Id.* at 11-12.
[657] Ex. 11 (Flowers direct) at attached Sched. 5, p. 1; Tr. at 104 (Flowers).

Economic Development

Dominion provided economic development studies of the CE-4 Projects conducted by Mangum, which are summarized in the table below.[658]

	Economic Impact During Construction				35-Year Operational Period			
	Jobs[659]	Wages and Benefits (millions)	Economic Output (millions)	State and Local Tax Revenue (millions)	Jobs, per year	Wages and Benefits (millions)	Economic Output (millions)	Local Tax Revenue[660] (millions)
Beldale	220	$18.4	$67.4	$2.4	4	$0.3	$1.1	$8.3
Bookers Mill	400	$26.9	$98.5	$3.6	7	$0.5	$1.6	$11.8
Blue Ridge	437	$40.3	$146.1	$5.4	14	$0.9	$3.4	$13.9
Michaux	187	$15.2	$56.1	$2.1	5	$0.3	$1.0	$5.9

The Mangum studies include disclaimers indicating, among other things, that their "estimates are intended to provide a general indication of likely future outcomes and should not be construed to represent a precise measure of those outcomes."[661] Staff indicated that there would likely be economic impacts from the CE-4 Projects, but took no position on how to quantify such impacts.[662]

Dominion further indicated that it will reasonably use goods and services sourced in whole or in part from Virginia businesses to execute these projects. Additionally, a provision in the EPC contracts requests the contractor use reasonable efforts to maximize the hiring of local residents by subcontractors and vendors.[663] The significant and widespread construction required by the proposed projects and PPA facilities offers employment opportunities across the Commonwealth.[664]

Environmental Justice and Impact on Historically Economically Disadvantaged Communities

Virginia law includes what could be considered procedural and substantive components of environmental justice in the development of renewable generation facilities. Procedurally, the

[658] Ex. 14. As defined above, "Mangum" refers to Mangum Economics, LLC.

[659] "Jobs" refers to the Mangum reports' estimates of direct, indirect, and induced job years. *See, e.g., id.* at Beldale Report, p. 1.

[660] For Beldale, Blue Ridge, and Michaux, this column nets the Mangum reports' estimated cumulative county tax revenue over 35-years from using the subject property (a) for the proposed solar project; and (b) for its current use. Ex. 14.

[661] *See, e.g., id.* at Beldale Report, p. 21.

[662] Tr. at 265 (Glattfelder).

[663] *See* Ex. 11 (Flowers direct) at attached Scheds. 4-7, p. 3 (for all).

[664] Such opportunities can benefit, among others, "local workers, historically economically disadvantaged communities ... veterans, and individuals in the Virginia coalfield region..." 2020 Va. Acts chs. 1193, 1194, Enactment Clause 7.

VEJ Act generally stresses the promotion of environmental justice through fair treatment and meaningful involvement.[665] The Commission – through its orders – has directed regulated utilities, like Dominion,[666] to take actions to ensure fair treatment and meaningful involvement consistent with the VEJ Act.[667] The record indicates that environmental justice outreach by Dominion and developers has occurred for Beldale, Blue Ridge, and Michaux, and, for some of these projects, may remain ongoing.[668] Dominion should continue any ongoing outreach for any of these projects approved by the Commission.

Substantively, the VCEA recognizes that the development of renewable energy facilities offers not only opportunities for local benefit but also adverse environmental impacts. Specifically, the Commission must "ensure that the development of new, or expansion of existing, energy resources or facilities does not have a disproportionate adverse impact on historically economically disadvantaged communities,"[669] while also "consider[ing] whether and how those facilities and programs benefit local workers [and] historically economically disadvantaged communities."[670]

For the CE-4 Projects, Dominion offered evidence in support of its consideration of environmental justice, including testimony offered by the Supervisor of Environmental Justice for Dominion Energy Services, Inc.[671] According to the Company, Beldale is located in an area that, due to income, is a "historically economically disadvantaged community" under the VCEA.[672] Blue Ridge is located in a "community of color" under the VEJ Act.[673] Michaux is located in an area that exceeds income and color thresholds under both the VCEA and the VEJ Act.[674]

---

[665] Code §§ 2.2-234 and 2.2-235.

[666] Appalachian Voices appeared to suggest that the VEJ Act applies to Dominion because one of the two statutes in the VEJ Act indicates that "[i]t is the policy of the Commonwealth to promote environmental justice and ensure that it is carried out throughout the Commonwealth." Tr. at 459-62. It is unclear how the VEJ Act could apply *directly* to Dominion. The VEJ Act includes a definition of "state agency" limited to the executive branch (Code § 2.2-234), was codified in a chapter of the Code for "Governor's Secretaries" (Code §§ 2.2-200 through 2.2-235), and was codified in a Title of the Code for the Administration of Government (Title 2.2).

[667] *See, e.g., 2020 RPS Plan Order*, 2021 S.C.C. Ann. Rep. at 252; *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing 2020 RPS Proceeding for Appalachian Power Company*, Case No. PUR-2020-00135, 2021 S.C.C. Ann. Rep. 254, 257, Final Order (Apr. 30, 2021); *Application of Virginia Electric and Power Company, For approval and certification of electric transmission facilities: Transmission Lines #2002 and #238/249 230 kV Partial Rebuild*, Case No. PUR-2021-00194, 2022 S.C.C. Ann. Rep. 334, 339, Final Order (Mar. 11, 2022).

[668] Ex. 11 (Flowers direct) at attached Sched. 4, p. 6, attached Sched. 5, p. 6, attached Sched. 6, p. 7, attached Sched. 7, p. 6.

[669] Code § 56-585.1 A 6. *See also* Code § 2.2-234 (definition of "[f]air treatment").

[670] 2020 Va. Acts chs. 1193, 1194, Enactment Clause 7.

[671] Ex. 11 (Flowers direct) at attached Scheds. 4-9; Ex. 53 (MacCormick rebuttal); Tr. at 439-65 (MacCormick). *See also* Ex. 54.

[672] Ex. 11 (Flowers direct) at attached Sched. 4, p. 6.

[673] *Id.* at attached Sched. 5, p. 6. Dominion indicated that community benefit funds have been set aside for Beldale, with the intent to work with local secondary and higher education institutions and other local stakeholders to establish a scholarship fund for environmental justice communities near the project. *Id.*

[674] *Id.* at attached Sched. 7, p. 6.

While Dominion did not dispute the potential presence of environmental justice populations near its proposed projects, the Company asserted that it has provided sufficient information about potential environmental impacts to conclude that these renewable energy facilities would not cause significant adverse and disproportionate impact to any community, including environmental justice communities or historically economically disadvantaged communities.[675]

The record does not identify environmental impacts that raise environmental justice concerns, in my opinion. Some environmental impacts associated with solar facilities are due to their construction, rather than their operation. For example, Beldale, Blue Ridge, and Michaux would require the clearing of forest land, as discussed above. However, the construction of solar facilities creates almost all of the jobs associated with these projects[676] – a beneficial opportunity for local residents that the VCEA directs the Commission to consider.[677] As discussed in the preceding section of this Report, a provision in Dominion's EPC contracts requests that contractors use reasonable efforts to maximize the hiring of local residents by subcontractors and vendors. Other environmental impacts these projects could potentially cause, visual impacts and potential erosion and sediment, are subject to screening and setback requirements and erosion and sediment control measures, which are part of the local review processes for these projects.[678] Localities would also benefit through increased local tax revenue from Beldale, Blue Ridge, and Michaux.[679]

Appalachian Voices drew the case participants' attention to the VEJ Act's indication that "fenceline communities" should be a focus of the Commonwealth's policy to promote environmental justice.[680] The VEJ Act definition of "fenceline community" is limited to areas that, among other things, "present[] an increased health risk to its residents due to its proximity to a major source of pollution."[681] The record does not identify a major source of pollution proximate to Beldale, Blue Ridge, or Michaux or any existing health risk to nearby residents that these proposed solar facilities could potentially aggravate.

(ii) Not Contrary to the Public Interest

The third criterion for evaluating CPCN requests under Code § 56-580 D is whether the proposed facilities "are not otherwise contrary to the public interest." However, it does not appear that the positive and negative public interest implications of the CE-4 Projects for which Dominion seeks CPCNs are to be weighed or considered by the Commission. As shown in the provisions of Code § 56-585.1 A 6 above, the General Assembly has deemed to be "in the public interest" Dominion's purchase or construction of solar and storage facilities far in excess of the amounts proposed in this case and prior proceedings.[682]

[675] Ex. 53 (MacCormick rebuttal) at 4.
[676] Ex. 14 (attributing more than 97% of the estimated "jobs" to the construction period for these four projects).
[677] 2020 Va. Acts chs. 1193, 1194, Enactment Clause 7.
[678] *See, e.g.*, Ex. 13.
[679] *See, e.g.*, Ex. 14.
[680] Tr. at 457-59 (MaCormick).
[681] Code § 2.2-234.
[682] Code § 56-585.1 A 6.

CPCN Recommendations for Beldale, Blue Ridge, Bookers Mill, and Michaux

The economic results for these utility-scale CE-4 Projects are generally consistent with what the Commission considered for the utility-scale CE-3 Solar Projects approved last year. Dominion's net present value results established by Dominion's PLEXOS modeling and avoided REC estimates (using any of the three scenarios) indicate that the portfolio of these CE-4 Projects is negative from a Dominion ratepayer perspective, even after incorporating the significant beneficial production tax credits from the Inflation Reduction Act.[683] However, the construction and operation of these CE-4 Projects would provide global benefits from reduced emissions. The levelized costs of energy calculated by Dominion are also comparable to those presented in support of the utility-scale CE-3 Solar Projects, which were approved by the Commission.

Based on the record evidence, I find that these utility-scale CE-4 Projects would reasonably and prudently help satisfy Dominion's large RPS compliance and energy needs. However, I do not find that these resources offer a meaningful or cost-effective means of satisfying Dominion's capacity needs. As discussed above, Dominion's estimated initial capacity value of **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][684] **[END EXTRAORDINARILY SENSITIVE INFORMATION]** This is a very high capacity cost for projects that would do little to meet the capacity requirements of modest peak load growth or retirements – much less the unprecedented level of peak load growth projected by Dominion or the significant retirements scheduled by the VCEA.

Because the construction of Beldale, Blue Ridge, Bookers Mill, and Michaux is a reasonable way to help satisfy Dominion's RPS compliance and energy needs, and based on Commission precedent, I recommend approval of these CE-4 Projects. I also find that conditioning CPCN approval on the uncontested DEQ recommendations is desirable or necessary to minimize adverse environmental impact. Accordingly, I recommend that the Commission approve CPCNs for Beldale, Blue Ridge, Bookers Mill, and Michaux, with such approval conditioned on the uncontested recommendations from the DEQ Report. In addition, I recommend Dominion provide its Michaux construction team with information about plant species of concern and coordinate with DCR-DNH if such a species is observed within the project area, unless such coordination would delay project construction. However, the record could also support denial of some, or all, of these proposed projects based on the economic evidence offered by Dominion. In particular, Dominion's evidence shows that, under all three scenarios evaluated by Dominion, Beldale, Blue Ridge, and Michaux are each less economic for Dominion's ratepayers than the market, based on Dominion's analysis that considers these projects' estimated energy, REC, and capacity values. Additionally, in most scenarios the estimated net present value detriment to ratepayers from each of these three facilities exceeds the global benefit Dominion estimates each would provide through reduced carbon emissions.

---

[683] *See, e.g.*, Ex. 22 (Notes).

[684] **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

III. PPA PRUDENCE

Code

Dominion seeks a prudence determination for the CE-4 PPAs pursuant to Code § 56-585.1:4, which states in part as follows:

> A utility may elect to petition the Commission, outside of a triennial or biennial review proceeding conducted pursuant to § 56-585.1, at any time for a prudency determination with respect to … the purchase by the utility of energy, capacity, and environmental attributes from solar … facilities owned by persons other than the utility….[685]

Analysis of CE-4 PPAs and Distributed Solar PPAs

Dominion seeks a prudence ruling on the following solar PPAs.[686]

Project	Size (MWac)	Locality	Interconnection	COD
CE-4 PPAs				
Windsor	85.0	Isle of Wight	Transmission	2026
Sycamore Cross	240.0	Isle of Wight	Transmission	2026
Richmond Hwy	5.0	City of Pamplin	Distribution	2027
Jessie DuPont Memorial	4.3	Wicomico Church	Distribution	2026
Winfield Solar	19.9	Sussex	Distribution	2026
Optimist Solar	36.2	Sussex	Distribution	2026
Flowers Solar	19.9	Dinwiddie	Distribution	2026
Highlands CF Ft 23	10.0	Wise	Transmission	2026
CE-4 Distributed Solar PPAs				
Nathalie C	3.0	Halifax	Distribution	2026
Waynesboro B	3.0	Augusta	Distribution	2026
Pivot Energy VA 7	3.0	City of Hurt	Distribution	2026
USS Mt. Sidney Solar	3.0	Augusta	Distribution	2026
USS Greenlaw Solar	3.0	Stafford	Distribution	2026

Dominion projects that these proposed solar PPAs will produce approximately 926,000 MWhs in 2027, an amount that tapers down as the underlying solar panels degrade, to approximately 836,000 MWhs in 2046, when these agreements would expire.[687] This energy can

---

[685] Code § 56-585.1:4 H.

[686] Ex. 41 (Ricketts) at 8. "COD" is the projected commercial operation date. As identified by Staff witness Ricketts, the Sycamore Cross and Windsor CE-4 PPAs allow for a range of capacities. In a recently concluded CPCN proceeding the design capacity for Sycamore Cross was identified as 203 MW. Ex. 41 (Ricketts) at 6-7 and Appendix AR-1, p. 17; *Application of Sycamore Cross Solar, LLC, For certificates of public convenience and necessity for a solar generating facility totaling up to 240 MWac in Isle of Wight County and Surry County, Virginia*, Case No. PUR-2023-00126, Final Order (Jan. 19, 2024).

[687] Ex. 20 (Morton direct) at 5; Ex. 21.

be used by Dominion to serve its customers, and an equivalent amount of RECs can be used for RPS compliance.[688] The 926,000 Virginia RECs the CE-4 PPAs are expected to produce represent 4.9% of the estimated REC need for 2027,[689] or approximately half of Dominion's estimated *increase* in REC requirements from 2026 to 2027.[690]

The approximately 435 MW of nameplate capacity for the proposed solar PPAs (or 398 MW with Sycamore Cross's design capacity figure) is comparable to the largest annual addition of solar PPAs proposed since the enactment of the VCEA.[691] However, it bears repeating that PJM – the entity that calculates Dominion's capacity obligation and values – does not value intermittent solar capacity at the nameplate value. The capacity values of the CE-4 PPAs and Distributed Solar PPAs, like those of the CE-4 Projects, are far less than the nameplate capacity values shown in the table above. In 2027, the first year when all the underlying resources are expected to be operational, Dominion projects that the total capacity value of these PPAs will be approximately **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**.[692] By 2046, when the PPAs reach the end of their terms, Dominion projects that the total degraded capacity value of these PPAs will be approximately 67 MW.[693]

Dominion's net present value analysis for the CE-4 PPAs and CE-4 Distributed Solar PPAs **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][694] [redacted][695] [redacted][696] [redacted][697] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

---

[688] One REC is generated from each MWh of applicable energy production. Ex. 20 (Morton direct) at 5.
[689] Ex. 4 (2023 RPS Development Plan) at Attachment 10. 925,700 / 18,793,649 = 4.9%.
[690] *Id.* 18,793,649 – 16,897,650 = 1,895,999. 925,700 / 1,895,999 = 48.8%
[691] Ex. 18 (Keefer direct) at 3.
[692] Ex. 21-ES; Tr. at 404-05 (Morton). Dominion adjusted PJM's 2027 capacity value. Exs. 21, 21-ES.
[693] Ex. 21-ES. Both the 2027 and 2046 amounts shown above use the Petition's capacity figure for Sycamore Cross, rather than the lower design capacity amount identified in the record.
[694] Ex. 20-ES (Morton direct) at attached Sched. 4.
[695] The four CE-4 Distributed Solar PPAs that use tracking technology are the bottom four listed on the above table: Waynesboro B, Pivot Energy VA 7, USS Mt. Sidney Solar, and USS Greenlaw Solar. *See, e.g.,* Ex. 21, notes.
[696] Ex. 20-ES (Morton direct) at attached Sched. 6.
[697] *Id.* at attached Sched. 5.

I find the VCEA created a need for the CE-4 PPAs and Distributed Solar PPAs, which will provide RECs that are necessary for RPS compliance, in addition to capacity and energy. As discussed in Section II of this Report's Analysis, even with approval of the proposed CE-4 Projects and the proposed PPAs, and a large offshore wind facility and other approved renewables becoming operational, a large near-term need for RECs from future projects and/or purchases would remain. In addition, even without considering the significant generation retirements scheduled by the VCEA (absent a reliability problem), Dominion's projected capacity and energy needs have increased significantly due to unprecedented load and peak load growth projections attributed to additional data center growth.

To be clear, concerns about the costs proposed by the Petition are not limited to costs associated with the solar facilities that Dominion proposes to own and operate. The record of this case also includes some cost evidence of concern regarding the proposed CE-4 PPAs and CE-4 Distributed Solar PPAs. **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][698] [redacted][699] [redacted][700] [redacted][701] [redacted][702] [redacted][703] [redacted][704] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

---

698 *See* Ex. 10-ES at Filing Sched. 46B, Statement 3, pp. 16-17.
699 *Id.* at Filing Sched. 46B, Statement 3, pp. 16-19
700 Ex. 19-ES.
701 *Id.*
702 Tr. Day 1 ES Session 2 at 10-11.
703 Ex. 10-ES at Filing Sched. 46 B, Statement 3, pp. 16-19.
704 *See, e.g., id.* at Filing Sched. 46B, Statement 3, pp. 16-18.

The significant and widespread construction required by the PPA facilities offers employment opportunities across the Commonwealth.[705] The jobs created by the PPA facilities, primarily during the construction period, and increased tax revenue would likely provide economic development benefits.[706] While all of the PPA facilities are located within environmental justice communities,[707] the VCEA recognizes that the development of renewable energy facilities offers both opportunities for local benefits and adverse environmental impacts, as discussed in Section II of this Report's Analysis. The record does not identify environmental impacts that raise environmental justice concerns, in my opinion.

Ultimately, I find that it is prudent for Dominion to enter into the CE-4 PPAs and CE-4 Distributed Solar PPAs. While providing limited capacity value, the proposed PPAs are reasonable ways to help satisfy Dominion's RPS compliance and energy needs **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][708] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

Analysis of PPAs in Future Proceedings

In its economic analysis, Dominion provided aggregated results for the four CE-4 Distributed Solar PPAs using tracking technology, which are four different three-MW facilities.[709] Staff recommended that Dominion be required in future RPS plan cases to provide the net present value analysis of each proposed PPA (and project) on an individual basis.[710] Staff indicated that separate net present values would clarify the impact of a particular project on the overall results and would make it easier to review and determine the merits of each specific project.[711] Dominion asserted that its approach of aggregating the economic analysis results of the Four Distributed PPA Trackers is reasonable and is consistent with the results presented in prior cases. Dominion indicated the individual results for these PPAs should be directionally similar based on the number of distributed solar PPAs and the similarity in their size.[712]

While distributed PPAs results have been aggregated in prior RPS plan proceedings, I recommend adoption of Staff's recommendation for such disaggregated analysis and results in future PPA prudence petitions. Disaggregated results would enable the Commission to review

---

[705] *See, e.g.*, Ex. 18 (Keefer direct) at attached Sched. 2 (maps showing the sites for all the proposed PPAs). Such opportunities can benefit, among others, "local workers, historically economically disadvantaged communities ... veterans, and individuals in the Virginia coalfield region..." 2020 Va. Acts chs. 1193, 1194, Enactment Clause 7.
[706] *See, e.g.*, Ex. 41 (Ricketts) at 26-27.
[707] *See, e.g.*, Ex. 18 (Keefer direct) at 10.
[708] Ex. 49-ES (Morton rebuttal) at 13.
[709] *See, e.g.*, Ex. 20-ES (Morton direct) at attached Scheds. 4-6 (showing aggregate results for "Four Distributed PPA Trackers").
[710] Ex. 41 (Ricketts) at 15-16 and Appendix AR-1, p. 29.
[711] Tr. at 271 (Ricketts).
[712] Ex. 49 (Morton rebuttal) at 9.

each PPA (and project) based on its individual merits. In the instant case, **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][713] [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

Staff also recommended that Dominion be directed to continue modeling at least three scenarios similar to those presented in this case.[714] The net present value analysis for the PPAs and the Company-owned projects in this case priced the avoided cost of RECs based on: (i) the statutory deficiency payment; (ii) a forecasted market price for RECs; and (iii) a blend of 30% forecasted REC market prices and 70% statutory deficiency payment penalties.[715] Staff indicated that the blended price may be an appropriate point of comparison that more closely aligns with what could occur.[716] Dominion agreed to Staff's recommendation with the caveat that the blended REC scenario would be modified to the extent Dominion adjusts its long-term planning assumptions regarding the availability of RECs.[717] I agree that a blended scenario should continue to be provided and recommend requiring such a scenario in future analysis without prescribing any blended percentages.

IV. CONSOLIDATION OF RIDERS PPA and CE

Code

Dominion requests the consolidation of Rider CE and Rider PPA. Rider CE currently recovers the costs of the Company-owned CE-1, CE-2, and CE-3 facilities approved in prior RPS plan proceedings, while Rider PPA recovers the costs of the CE-1, CE-2, and CE-3 PPAs. As proposed, the existing Rider PPA would end on April 30, 2024. Effective May 1, 2024, costs associated with the approved CE-1, CE-2, and CE-3 PPAs and the proposed Rider CE-4 PPAs would be recovered through Rider CE. Dominion requested this rate consolidation pursuant to following provision in Code § 56-585.1 A 7, which was enacted during the 2023 General Assembly Session:[718]

> At any time, the Commission may, in its discretion, for [Dominion], upon petition by such a utility or upon its own initiated proceeding, direct the consolidation of any one or more subsets of rate adjustment clauses previously implemented pursuant to subdivision 5 or 6 in the interest of judicial economy, customer transparency, or other factors the Commission determines to be appropriate. Any subset of rate adjustment clauses so consolidated shall continue to be considered by the Commission without regard to the other costs, revenues, investments, or

---

[713] Ex. 49-ES (Morton rebuttal) at 13.
[714] *See, e.g.*, Ex. 41 (Ricketts) at 23.
[715] Ex. 20-ES (Morton direct) at 14 and attached Scheds. 1-6.
[716] Ex. 41 (Ricketts) at 22.
[717] Ex. 49 (Morton rebuttal) at 6.
[718] 2023 Va. Acts chs. 757, 775.

earnings of the utility and remain as a cost recovery mechanism independent from the utility's rates for generation and distribution services pursuant to § 56-585.8 and subdivisions 5 and 6, but will be combined as a single rate adjustment clause for cost recovery and review purposes. Any rate adjustment clause or subset of rate adjustment clauses so consolidated shall be named in a manner, as determined by the Commission, that reasonably informs customers as to the nature of the costs recovered by the consolidated rate adjustment clause.

Analysis of Proposed Rate Adjustment Clause Consolidation

Dominion asserted that its proposed consolidation of Riders CE and PPA would serve the interests of judicial economy and customer transparency because of the similarity of the underlying resources and since the Commission already considers the prudence of PPAs in the annual RPS plan cases.[719] As proposed, all new solar and storage resources that Dominion develops pursuant to the VCEA – whether Company-owned or PPA – would be recovered through the same rate adjustment clause. Dominion further asserted that reducing the number of rate adjustment clauses and associated rate changes is beneficial to many stakeholders – including the Commission, Dominion, and customers.[720] In addition, cost savings could result from Dominion having to satisfy one less annual public notice requirement.[721]

Appalachian Voices opposed the proposed consolidation of Riders CE and PPA, asserting that such consolidation would reduce transparency for customers on their monthly bills. Because the solar PPAs approved to date have resulted in credits lowering customers' monthly bills, Appalachian Voices expressed concern that consolidation would mask the differing bill impacts from PPAs compared to Company-owned facilities.[722] Appalachian Voices expressed a similar transparency concern that consolidation would eliminate these differing impacts from Commission reports to the General Assembly pursuant to Code § 56-596 B, and pointed to a recent report showing, among other bill impacts, Rider PPA rates as a credit to residential customer bills, and Rider CE rates as a charge.[723]

While Consumer Counsel did not find assertions regarding judicial economy objectionable, Consumer Counsel opposed consolidation based on customer transparency concerns. In Consumer Counsel's opinion, customers should not have to resort to filing schedules to understand bill impacts from Company-owned resources compared to third-party owned facilities and the cleanest way to keep these impacts segregated would be to keep the rate adjustment clauses separate.[724]

Dominion argued that the costs and benefits of PPAs would continue to be transparent after consolidation. Dominion intends to calculate the revenue requirement for a consolidated Rider CE by categories, including a category for all approved PPAs.[725]

---

[719] Ex. 27 (Lecky direct) at 4-5.
[720] Ex. 57 (Lecky rebuttal) at 4.
[721] Tr. at 480 (Lecky).
[722] Ex. 35 (Abbott) at 32-33.
[723] Tr. at 211-15 (Abbott).
[724] Tr. at 567-68 (Farmer).
[725] Ex. 57 (Lecky rebuttal) at 3 (pointing to Schedule 1 of her direct testimony as an example of this approach).

Staff does not oppose the proposed consolidation.[726] Staff indicated that the cost allocation and rate design for Riders CE and PPA have no differences.[727]

As shown in the Code provisions above, the Commission has broad discretion to determine whether Riders CE and PPA should be consolidated. The Commission can require or deny consolidation based on any "factors the Commission determines to be appropriate" – including, but not limited to, judicial economy and customer transparency.[728]

I find that consolidation of Riders CE and PPA is in the interest of judicial economy. The number of public utility cases and hearings conducted by the Commission has increased with the proliferation of legislated rate adjustment clauses.[729] Consolidation would eliminate one annual Commission hearing, and the associated process that begins with a petition and ends with a Commission final order.[730] In my opinion, the nature of Rider PPA makes it an attractive candidate for achieving judicial economy because a standalone Rider PPA case is largely mathematical. The primary Rider PPA costs are payments to third parties based on contract prices the Commission has already determined are prudent and energy output from facilities that Dominion does not own or operate. Some of the more complicated aspects of Rider PPA were decided by the *Proxy Value Order*, and are common to the Rider CE and Rider PPA costs.[731] In the instant case, Staff's revenue requirement calculations for Rider PPA costs are shown on only nine pages of Staff schedules.[732] Accordingly, consolidation would appear to eliminate one annual Commission proceeding by shifting a relatively limited amount of work to another existing annual proceeding.

Eliminating one annual rate change and the cost associated with public notice would also appear beneficial to customers and the Company. Because rate adjustment clauses provide dollar-for-dollar recovery of costs, Dominion will recover all of its prudent costs for RPS facilities and PPAs, regardless of the number of adjustments that are made to customers' rates. Such costs include the costs of public notices coordinated by the Company.

The effect of rate consolidation on customer transparency, which was the basis for opposition by Appalachian Voices and Consumer Counsel, could depend on the context. Since the costs of VCEA compliance are scattered across several rate adjustment clauses, consolidation of Riders CE and PPA could provide a more transparent (albeit incomplete) view of the costs and bill impacts of resources the Commission has approved for VCEA compliance. On the other

---

[726] Tr. at 243 (Brunelle).

[727] Ex. 37 (Brunelle) at 34-38. Mr. Brunelle cited the following language from the *Proxy Value Order*: "It is reasonable and appropriate to use the same allocation methodology to allocate Company-owned resources and PPAs." *See Proxy Value Order* at 7. *See also* Ex. 37 (Brunelle) at Attachment TRB-1 (Dominion's response to Staff discovery request no. 3-96(c)).

[728] Code § 56-585.1 A 7.

[729] *See, e.g.*, Ex. 36 (Otwell) at Appendix B. This appendix identifies 15 generation function-related rate adjustment clauses for Dominion. Dominion also has transmission and distribution function-related rate adjustment clauses. APCo also has its own rate adjustment clauses.

[730] This is consistent with the statutory directive for rate adjustment clauses combined pursuant to Code § 56-585.1 A 7 to be "combined … for …review."

[731] *See, e.g., Proxy Value Order* at 7 ("It is reasonable and appropriate to use the same allocation methodology to allocate [the costs and benefits of] Company-owned resources and PPAs.").

[732] Ex. 36 (Otwell) at attached Scheds. 40-48. Staff also calculated lifetime revenue requirement figures for PPAs.

hand, for the costs and bill impacts of Company-owned resources approved for VCEA compliance by the Commission distinct from those of third-party resources, consolidation of Rider CE and PPA could provide a less transparent (albeit incomplete) view of that information, as emphasized by Appalachian Voices.[733]

However, even if the Commission views customer transparency through the same lens as Appalachian Voices, it appears that the relative impact of Rider PPA and Rider CE projects can be ascertained with information that would continue to be provided with fully consolidated rates. Hearing Examiner's Attachment 1 uses four pieces of information – none of which would be eliminated by consolidation – to separate the contributions of Rider PPA projects and Rider CE projects to the Petition's consolidated rate impact on a residential customer with 1,000 kWh monthly usage.[734] A residential customer with this assumed level of usage is the basis on which the Commission regularly communicates rate information to the public and the General Assembly, including in the recent report highlighted by Appalachian Voices.[735]

Based on my assessment of the record, I recommend that the Commission approve consolidation of Riders CE and PPA, subject to Dominion identifying in its future Rider CE petitions: (a) the total monthly bill impact of the proposed revenue requirement on a residential customer's monthly bill, based on 1,000 kWh monthly usage; and (b) the relative contributions of Company-owned resources and PPAs to that total monthly bill impact. While I do not presume to know the content of future Commission orders or reports, the Company's provision of such information in future petitions would facilitate the inclusion of such information in future procedural orders or notices in addition to reports on pending rate changes, should the Commission decide to distinguish the contributions of Company-owned resources and PPAs to a consolidated Rider CE. If, for customer transparency or any other reason the Commission finds appropriate, the Commission decides to distinguish such impacts in final orders, the information to do so would remain available to do in such cases, regardless of consolidation.

Because the Rider CE projects and Rider PPA agreements are all VCEA/RPS compliance resources that are commonly referred to as clean energy, I find that the existing rate adjustment clause name "Rider CE" would "reasonably inform[] customers as to the nature of the costs recovered by the consolidated rate adjustment clause."[736] However, the tariff heading should be changed from "Clean Energy Projects"[737] to "Clean Energy Projects and Power Purchase Agreements."

---

[733] Either of the comparisons discussed above are incomplete because, among other things, the costs included in Riders CE and PPA are not the only costs of complying with the VCEA or RPS. *See, e.g.*, Ex. 4 (2023 RPS Development Plan) at Attachment 11 (identifying Riders CE, PPA, RPS and OSW as rates related to the RPS Program). In addition, energy "benefits" that are netted out of Riders CE, PPA and OSW, to implement Code § 56-585.5 F, are recovered by Dominion through the fuel factor. *2020 RPS Plan Order*, 2021 S.C.C. Ann. Rep. at 252.

[734] The Company affirmed that if consolidation is approved, the Company would still provide the PPA revenue requirement broken out. Tr. at 493 (Lecky). The other three pieces of information (total revenue requirement, residential allocation factor, and 12 month kWh forecast) are provided in all of Dominion's rate filings, including RPS plan cases.

[735] Tr. at 212 (Abbott) (discussing bill impacts reported by the Commission to the General Assembly based on a residential customer with 1,000 kWh monthly usage).

[736] Code § 56-585.1 A 7.

[737] *See, e.g.*, Ex. 28 (Hewett direct) at attached Sched. 2.

While I recommend consolidation of Riders CE and PPA, as set forth above, I recognize the Commission could weigh the evidence in this case differently. The Commission has broad discretion to determine whether Riders CE and PPA should be consolidated, based on any factor that the Commission deems appropriate, including, but not limited to, those discussed above.

V. PROPOSED RIDER CE

Code – PPA Costs

Dominion seeks approval to recover, through a consolidated Rider CE, the costs of all CE-1, CE-2, and CE-3 PPAs previously approved by the Commission and the CE-4 PPAs proposed in the instant proceeding, pursuant to Code § 56-585.1 A 5. Code § 56-585.1 A 5 states in part as follows:

> 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:
>
> ...
>
> Projected and actual costs of compliance with renewable energy portfolio standard requirements pursuant to § 56-585.5 that are not recoverable under subdivision 6. The Commission shall approve such a petition allowing the recovery of such costs incurred as required by § 56-585.5, provided that the Commission does not otherwise find such costs were unreasonably or imprudently incurred;[738]

Code § 56-585.1 D states in 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.). In determining the reasonableness or prudence of a utility providing energy and capacity to its customers from renewable energy resources, the Commission shall consider the extent to which such renewable energy resources, whether utility-owned or by contract, further the objectives of the Commonwealth Clean Energy Policy set forth in § 45.2-1706.1, and shall also consider whether the costs of such resources is [sic] likely to result in unreasonable increases in rates paid by customers.

---

[738] Code § 56-585.1 A 5 d.

Analysis of Proposed PPA Costs

Staff and Dominion agreed on a revenue requirement calculation for a consolidated Rider CE, including for the approved CE-1, CE-2, and CE-3 PPAs in addition to the proposed PPAs.[739] No case participant has asserted that the costs of these PPAs and/or the proposed PPAs are likely to result in unreasonable increases in rates paid by customers.

For the PPAs that the Commission has previously approved, no evidence indicates that any actual PPA costs proposed for recovery were imprudently incurred, or that any forecasted or actual PPA costs are unreasonable. The Commission has previously found the contract prices for these PPAs to be reasonable. Accordingly, the record supports approval of their recovery under Code § 56-585.1 A 5, as proposed in the Petition.

For the proposed PPAs, Section III of this Report's Analysis recommends their approval. If the Commission adopts that recommendation, the associated cost recovery should also be approved, as proposed in the Petition. However, if the Commission rejects any proposed PPA(s), any associated costs would need to be removed from the approved revenue requirement.

Staff observed that the final capacity for several PPA facilities with an allowed capacity range ended up at or towards the lower end of the range. Staff recommended that, where available, the Commission require Dominion to report both the low-end and high-end of the range of potential capacities for future PPAs for solar facilities that have not yet completed construction.[740] Dominion did not oppose this recommendation.[741] I find that future Rider CE filings (or Rider PPA, if consolidation is denied) should identify the high-end and low-end of potential capacities, if applicable, for PPAs associated with solar facilities that have not yet completed construction.

Code – Company-Owned Project Costs

Also through Rider CE, Dominion seeks approval to continue recovering costs of all CE-1, CE-2, and CE-3 projects/facilities previously approved by the Commission, and to initiate cost recovery for the proposed CE-4 Projects, including interconnection facilities, through a rate adjustment clause pursuant to Code § 56-585.1 A 6.

Code § 56-585.5 D states in part as follows:

> To the extent that [Dominion] constructs or acquires new zero-carbon generating facilities or energy storage resources, the utility shall petition the Commission for the recovery of the costs of such facilities, at the utility's election, either through its rates for generation and distribution services or through a rate adjustment clause pursuant to subdivision A 6 of § 56-585.1....

[739] *See, e.g.*, Ex. 57 (Lecky rebuttal) at 2.
[740] Ex. 41 (Ricketts) at 7 and Appendix AR-1, p. 17. In this context "final" capacity appears to refer to the finalized initial nameplate capacity of the relevant projects.
[741] Ex. 47 (Keefer rebuttal) at 3.

Code § 56-585.1 A 6 states in part as follows:

To ensure the generation and delivery of a reliable and adequate supply of electricity, to meet the utility's projected native load obligations and to promote economic development, a utility may at any time ... petition the Commission for approval of a rate adjustment clause for recovery on a timely and current basis from customers of the costs of ... (ii) one or more other generation facilities.... A utility that constructs or makes modifications to any such facility, or purchases any facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, shall have the right to recover the costs of the facility, as accrued against income, through its rates, including projected construction work in progress, and any associated allowance for funds used during construction, planning, development and construction or acquisition costs, life-cycle costs, costs related to assessing the feasibility of potential sites for new underground facilities, and costs of infrastructure associated therewith....

The costs of the facility, other than return on projected construction work in progress and allowance for funds used during construction, shall not be recovered prior to the date a facility constructed by the utility and described in clause (i), (ii), (iii) or (v) begins commercial operation, the date the utility becomes the owner of a purchased generation facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses....

....

The construction or purchase by a utility of one or more generation facilities with at least one megawatt of generating capacity, and with an aggregate rated capacity that does not exceed 16,100 [MW], including rooftop solar installations with a capacity of not less than 50 [kW], and with an aggregate capacity of 100 [MW], that use energy derived from sunlight or from onshore wind and are located in the Commonwealth or off the Commonwealth's Atlantic shoreline, regardless of whether any of such facilities are located within or without the utility's service territory, is in the public interest, and in determining whether to approve such facility, the Commission shall liberally construe the provisions of this title. A utility may enter into short-term or long-term power purchase contracts for the power derived from sunlight generated by such generation facility prior to purchasing the generation facility....

....

The Commission shall likewise enter its final order with respect to any petition by a utility for a certificate to construct and operate a generating facility or facilities utilizing energy derived from sunlight, pursuant to subsection D of § 56-580, within six months after the date of filing such petition....

....

Notwithstanding any provision of Chapter 296 of the Acts of Assembly of 2018, construction, purchasing, or leasing activities for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from onshore wind with an aggregate capacity of 16,100 [MW], including rooftop solar installations with a capacity of not less than 50 [kW], and with an aggregate capacity of 100 [MW], together with a utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore wind with an aggregate capacity of not more than 3,000 [MW], are in the public interest. Additionally, energy storage facilities with an aggregate capacity of 2,700 [MW] are in the public interest....

....

For purposes of this subdivision, "general rate of return" means the fair combined rate of return on common equity as it is determined by the Commission for such utility pursuant to subdivision 2.

Code § 56-585.1 D states in 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.). In determining the reasonableness or prudence of a utility providing energy and capacity to its customers from renewable energy resources, the Commission shall consider the extent to which such renewable energy resources, whether utility-owned or by contract, further the objectives of the Commonwealth Clean Energy Policy set forth in § 45.2-1706.1, and shall also consider whether the costs of such resources is [sic] likely to result in unreasonable increases in rates paid by customers.

Analysis of CE-1, CE-2, and CE-3 Cost Updates

Staff and Dominion agreed on a revenue requirement calculation for a consolidated Rider CE, including for the CE-1, CE-2, and CE-3 Projects.[742] The record established that since last year's RPS plan case Dominion's estimated capital costs, excluding financing costs, have not changed for the CE-1 Projects[743] and CE-3 Projects,[744] but have increased by $174.8 million (12%) for the CE-2 Projects.[745]

Most of this increase for the CE-2 Projects is due to the $164.1 million increase (59%) in the projected costs of the Dulles Solar + Storage project.[746] Dominion attributed this significant increase to federal delays and requirements, a change in the storage EPC contractor and supplier, a redesign of the solar array, and pandemic impacts on supply chain and equipment procurement. The primary factor, according to Dominion, was the project's location on federal land and the associated requirements for obtaining federal approvals.[747]

No case participant challenged the reasonableness or prudence of any costs incurred for the CE-1, CE-2, or CE-3 Projects or the reasonableness of Dominion's projected costs for these projects. Nor has any case participant asserted that the costs of these projects are likely to result in unreasonable increases in rates paid by customers.

Analysis of the CE-4 Project Costs – Including for Peppertown and the CE-4 Distributed Solar Project (Alberta)

As discussed above, Staff and Dominion agreed on a revenue requirement calculation for a consolidated Rider CE, which includes costs for all of the proposed CE-4 Projects and Distributed Solar Project.[748] I find that the record supports approval of the uncontested requirement for each of these projects that the Commission approves in this case. Should the Commission deny a CPCN for Beldale, Blue Ridge, Bookers Mill, or Michaux and/or deny cost recovery for Peppertown or Alberta (*i.e.*, the CE-4 Distributed Solar Project), the associated revenue requirement(s) should be removed from Rider CE. Because Dominion does not seek a CPCN for Peppertown or Alberta, those projects were not analyzed above in Section II of this Report's CPCN Analysis. Consequently, while no case participant has opposed Peppertown or Alberta, the analysis below considers whether the costs of these two projects are reasonable and prudent for recovery from customers pursuant to Code §§ 56-585.1 A 6 and 56-585.1 D.

Peppertown and Alberta are the two projects that Dominion proposes to acquire upon mechanical completion by their developer.[749] While Dominion provided a draft asset purchase

[742] *See, e.g.*, Ex. 57 (Lecky rebuttal) at 2.
[743] Ex. 11 (Flowers direct) at attached Sched. 1, p. 1.
[744] *Id.* at attached Sched. 3, p. 1.
[745] *Id.* at attached Sched. 2, pp. 1, 10. $9.7 million + $164.1 million + 0 + $0.99 million = $174.79 million. $174.79 million/($1,127.5 million + $279.7 million + $41.2 million + $14.9 million) = 11.95%.
[746] Since last year's RPS plan case, the estimated capital costs for Dulles Solar + Storage increased from $279.7 million to $443.7 million, excluding financing costs. *Id.* at attached Sched. 2, p. 1.
[747] *See, e.g.*, Tr. at 109-13 (Flowers).
[748] *See, e.g.*, Ex. 57 (Lecky rebuttal) at 2.
[749] *See, e.g.*, Ex. 11 (Flowers direct) at 13-14.

agreement for the record,[750] Dominion still did not have a final executed agreement when the hearing concluded.[751] The table below summarizes most of the Company's cost and economic evidence for Peppertown and Alberta.[752]

CE-4 Project	Capital Cost	Levelized Cost of Energy (Dollars per Megawatt-Hour)		Net Present Value for Dominion's System Based on Modeling Runs Plus Three Different Values of Avoided REC Cost (Millions)			Net Present Value for the World Based on Social Cost of Carbon (Millions)
Peppertown 5 MW	$16.5 million	RECs	No RECs	1	2	3	$3
	$3,307/kW	$134.99	$146.94	($8)	($12)	($10)	
Alberta 3 MW	$10.9 million	RECs	No RECs	1	2	3	$3
	$3,642/kW	$136.71	$148.65	($6)	($9)	($7)	

As shown above, Peppertown and Alberta are not economic under any scenario presented by Dominion. Dominion's analysis that paints these two resources in the *best* light shows, on a net present value basis, a $14.3 million detriment to Dominion's ratepayers and only a $5.6 million global benefit from the reduction in carbon emissions that the Company attributes to these projects.[753] Dominion's analysis that paints these resources in the *worst* light shows, on a net present value basis, a $21.1 million detriment to Dominion's ratepayers against the same $5.6 million global benefit from carbon reduction.[754] In other words, Dominion's evidence indicates that the negative value to its ratepayers would be between two and four times the positive value for the entire world from reduced carbon emissions.

The high cost of Peppertown and Alberta to Dominion's ratepayers is also evidenced by the Company's high levelized cost of energy calculations for these facilities, as shown in the table above. The levelized costs of energy of approximately $135 to $149 per MWh, discounted to 2023 dollars,[755] for these two *generation* facilities are comparable to the per MWh cost Dominion's residential customers were charged in 2023 for the bundle of *generation, transmission, and distribution* facilities used to serve them.[756] As shown below, Dominion's

[750] Ex. 15-ES.

[751] Tr. at 114-15 (Flowers) (indicating Dominion does not expect the cost or scope to change from a draft agreement, but also does not expect to finalize an agreement until the end of February).

[752] *See, e.g.*, Ex. 11 (Flowers direct) at attached Sched. 8, p. 1, Sched. 9, p. 1; Ex. 49 (Morton rebuttal) at 13.

[753] Ex. 20 (Morton direct) at attached Sched. 1. This is the scenario that values the avoided cost of RECs at the statutory deficiency penalty.

[754] *Id.* at attached Sched. 2. This is the scenario that values the avoided cost of RECs at Dominion's forecasted REC prices.

[755] Ex. 49 (Morton rebuttal) at 13. Staff presented levelized cost of energy figures for Peppertown and Alberta that are higher than the figures shown above. Ex. 40 (Glattfelder) at 55.

[756] Ex. 28 (Hewett direct) at attached Sched. 3, p. 1. 1,000 kWh = 1 MWh.

high levelized cost of energy calculations for Peppertown and Alberta are roughly double the Company's calculations for Bookers Mill.[757]

Project Name	Type	Solar MW	RECs 35 Yr $/MWh	No RECs 35 Yr $/MWh
Beldale	Utility-Scale Solar	57.00	$ 85.21	$ 93.47
Blue Ridge	Utility-Scale Solar	95.00	$ 85.70	$ 93.95
Bookers Mill	Utility-Scale Solar	127.00	$ 66.91	$ 78.86
Michaux	Utility-Scale Solar	50.00	$ 80.54	$ 88.80
Peppertown	Utility-Scale Solar	5.00	$ 134.99	$ 146.94
Alberta	Distributed Solar	3.00	$ 136.71	$ 148.65

Notes: (1) Assumes design capacity factor for all solar projects. (2) All values in 2023 dollars.

At 5 MW and 3 MW, respectively, Peppertown and Alberta are too large to create the RECs that are more valuable under the VCEA.[758] Additionally, these projects use fixed-tilt technology, which generally provides lower capacity value and energy production than tracking technology.[759] Dominion's estimated initial capacity value of **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]** provided in total by these projects equates to **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]** – a cost figure that is almost double that of the CE-4 Projects for which Dominion seeks a CPCN.[760] Peppertown also has a design capacity factor of only 18.8%,[761] which indicates a relatively low expected level of energy and associated REC production.[762]

The Commission has recognized that the "the VCEA does not require the Commission to approve cost recovery for all new projects *at any cost*."[763] While the Commission could draw the line differently depending on how it weighs the evidence, I find the costs of Peppertown and Alberta too high to recommend their recovery from ratepayers. I recognize that the estimated capital expenditures of these projects totaling $27.4 million (excluding financing costs) is

---

[757] Exs. 49 (Morton rebuttal) at 13.

[758] Code § 56-585.5 D 5 (establishing a higher statutory deficiency penalty for shortfall in procuring RECs for resources that are 1 MW or less). Peppertown is also too large to satisfy the statutory petition requirements for projects that are three MWs or less, although Alberta does. Code § 56-585.5 D 2.

[759] *See, e.g.*, Ex. 37 (Brunelle) at 23-24; Ex. 21-ES. According to Dominion, "the developer opted to procure solar photovoltaic panel arrays using ground-mounted fixed tilt technology." Ex. 11 (Flowers direct) at attached Sched. 8, p. 1. While Mr. Flowers described a process by which the Company determines whether a solar project would be optimally constructed using fixed tilt or tracking technology, he did not believe the Company conducted such a comparison for the proposed Peppertown or Alberta facilities. Tr. at 120-21 (Flowers).

[760] **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

[761] Ex. 11 (Flowers direct) at attached Sched. 8, p. 2.

[762] *See, e.g.*, Ex. 4 (2023 RPS Development Plan) at Attachment 4 (rev. Nov. 9, 2023) (showing historical capacity factors above 18.8% for all solar facilities constructed after 2017).

[763] *2022 RPS Plan Order* at 9 (emphasis in original).

relatively small compared to the capital expenditures approved to date for VCEA compliance. However, the impact on ratepayers from the approved VCEA resources and costs is escalating, with pending proposals for Riders CE, PPA, OSW, and RPS alone proposed to increase the monthly bill of a residential ratepayer using 1,000 kWh by more than nine dollars.[764] Such increases make it more difficult for ratepayers to afford, and for me to recommend, proposed resources that are as uneconomic as Dominion's net present value and levelized cost of energy evidence indicates Peppertown and Alberta would be.

Moreover, for Peppertown **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][765] [redacted][766] [redacted][767] [redacted][768] [redacted][769] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

---

[764] Based on the monthly bill of a residential ratepayer using 1,000 kWh, Dominion's Petition proposed to increase Rider CE/PPA by $1.54, from $1.41 to $2.95. Dominion's proposed increase to Rider OSW would increase such monthly residential bill by $3.89, from $4.74 to $8.63, per month. *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider OSW, Coastal Virginia Offshore Wind Commercial Project, for the Rate Year Commencing September 1, 2024*, Case No. PUR-2023-00195, Order for Notice and Hearing (Nov. 21, 2023). Dominion's proposed Rider RPS would increase such monthly residential bill by $3.84, from $1.32 to $5.16, per month. *Petition of Virginia Electric and Power Company, For revision of a rate adjustment clause, designated Rider RPS, under § 56-585.1 A 5 d of the Code of Virginia for the Rate Year commencing September 1, 2024*, Case No. PUR-2023-00221, Order for Notice and Hearing (Jan. 5, 2024). To implement the Code § 56-585.5 F "net of benefits" provisions, Rider CE/PPA and OSW rates are decreased by energy credits. The cost of these energy credits is shifted to the fuel factor paid by Dominion's customers, and therefore is not reflected in the Rider CE/PPA bill amounts shown herein. *2020 RPS Plan Order*, 2021 S.C.C. Ann. Rep. at 252. The cumulative effect of these rate adjustment clause increases is significant, and renewable resources are not the only category of costs placing upward pressure on customer rates.

[765] Ex. 48-ES; Ex. 10-ES at Filing Sched. 46B, Statement 1, p. 91.

[766] *See, e.g.,* Ex. 9 at Filing Sched. 46B, Statement 1, p. 66.

[767] The net present value economic analysis used by Dominion to evaluate the short-listed PPAs from that RFP is the same as the economic analysis presented in the Petition. Tr. at 137-38 (Keefer). The 2023 Peppertown PPA offer was not short-listed, and therefore was not subjected to net present value analysis during the evaluation process. *See, e.g.,* Ex. 9 at Filing Sched. 46B, Statement 1, pp. 4-5; Ex. 10-ES at Filing Sched. 46B, Statement 1, p. 97.

[768] Ex. 23-ES.

[769] Tr. Day 1 ES Session 3 at 7 (Morton).

[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]

[redacted][770] [redacted]

[redacted][771] [redacted][772] [redacted][773] [redacted][774] [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

The *2022 RPS Plan Order* approved two 3 MW solar facilities even though they had negative net present value results. In doing so, the Commission recognized that those resources were identified through a competitive procurement process and indicated that lower individual project development and capital costs can provide greater opportunities to use a more diverse set of project developers. However, that rationale offers limited support for Alberta and Peppertown in this case **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted]
[END EXTRAORDINARILY SENSITIVE INFORMATION]

Several benefits Dominion offered in support of Peppertown – EPC diversity, resource specifications, locational value, and economic development benefits – are qualified, if not dampened, by the Company's prior rejection of Peppertown PPAs and the preceding local approval for this facility. In the instant case, Dominion indicated that the Peppertown project brings a new EPC contractor into the fold, and emphasized the Company's efforts to add new

---

[770] **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

[771] Ex. 49 (Morton rebuttal) at 12; Tr. Day 1 ES Session 3 at 8 (Morton).

[772] Ex. 49 (Morton rebuttal) at 13; Ex. 40 (Glattfelder) at 54-55.

[773] *See, e.g.*, Ex. 40 (Glattfelder) at 54; Ex. 49 (Morton rebuttal) at 12-13.

[774] Ex. 9 at Filing Sched. 46B, Statement 1, p. 85.

EPC contractors.[775] But it is unclear how this distinguishes the Peppertown project as a PPA compared to a Company-owned project. **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted][776] [redacted][777] [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]**

Dominion also indicated that its Company-owned projects are held to different specifications than are PPA projects, and cited cybersecurity and physical security (specifically taller, barbed wire fencing).[778] But the record does not indicate whether these requirements would differ for Peppertown based on its ownership. Fencing is a matter that numerous Commission cases (including this one) have revealed to be local matters considered and specified in the special or conditional use permit process. The special use permit for Peppertown was obtained in the summer of 2022, which was before the most recent PPA for this project was offered and rejected.[779]

Dominion also emphasized the value that distribution-interconnected generation provides by serving local load, especially during the summer, without requiring energy delivery on the transmission system.[780] That same locational value would exist if the energy was purchased through a PPA or generated by Dominion. When evaluating PPA bids, the Code requires Dominion to consider, among other things, "the location and effect on the transmission grid of a generation facility."[781] Nothing in the record suggests that the location of Peppertown, which was approved by Hanover County in 2022, or its interconnection changed in the last few months.

Dominion indicated that Peppertown would provide economic benefits to Hanover County, the region, and the Commonwealth – including a one-time payment to the County followed by annual payments of $1,400/MW.[782] However, the types of economic benefits estimated by Mangum would occur regardless of whether Peppertown was constructed for a PPA or for the Company to own. When evaluating PPA bids, the Code requires Dominion to consider, among other things, "benefits to the Commonwealth that are associated with particular projects, including regional economic development and the use of goods and services from Virginia businesses."[783] Moreover, the level of payments to the Commonwealth's localities is determined during the local approval process for a solar facility, which, as discussed above, was completed for Peppertown before its developer submitted its most recent PPA bid to Dominion for this project.

[775] Tr. at 356 (Flowers).
[776] Ex. 15-ES at Draft Asset Purchase Agreement, p. 7, and Draft EPC Contract, p. 1.
[777] Ex. 48-ES; Ex. 10-ES at Filing Sched. 46B, Statement 1, p. 91.
[778] Tr. at 354-55 (Flowers).
[779] Tr. at 383 (Ryan).
[780] Tr. at 355-56 (Flowers).
[781] Code § 56-585.5 D 3 (5).
[782] Tr. at 356-57 (Flowers).
[783] Code § 56-585.5 D 3 (6).

Dominion also cited the statutory 65%/35% petition requirement[784] and the need for in-state RECs that Peppertown would create as a reason the Company pursued Peppertown as a Company-owned project, rather than a PPA.[785] But in-state RECs would also be created by a Peppertown facility under a PPA arrangement. Additionally, the petition requirements do not control the Commission's standard for approval based on the merit of specific resources. The Commission's recognition that "the VCEA does not require the Commission to approve cost recovery for all new projects *at any cost*"[786] applies to Company-owned proposals that would create Virginia RECs. And the economic evidence in the instant case indicates that even if the Virginia RECs are valued at the statutory penalty rate – the outer-bound of their value[787] – these resources are uneconomic and the detriment to Dominion's ratepayers from the Company owning and operating Peppertown and Alberta is much greater than the global benefit these resources would provide.[788]

In sum, the record demonstrates that Dominion's ratepayers would be far better off if Dominion pursued alternative options to purchasing Peppertown and Alberta. **[BEGIN EXTRAORDINARILY SENSITIVE INFORMATION]** [redacted] **[END EXTRAORDINARILY SENSITIVE INFORMATION]** Additionally, several benefits Dominion offered in support of Peppertown are qualified, if not dampened, by the Company's prior rejection of Peppertown PPAs and the preceding local approval for this facility. Accordingly, I recommend the Commission deny cost recovery for Peppertown and Alberta and approve a $133.28 million consolidated revenue requirement. This amount is $3.40 million lower than the consolidated revenue requirement proposed by the Petition and $1.88 million lower than Staff's revenue requirement calculation to which Dominion subsequently agreed.[789]

Rate Design and Cost Allocation

The proposed rate design and cost allocation methodology have not been opposed for purposes of setting rates in the instant case.

Ongoing Waiver Request

The Commission's Rate Case Rules require rate adjustment clause applications filed pursuant to Code § 56-585.1 A 5 or A 6 to include, among other things:

> [t]he annual revenue requirement over the duration of the proposed rate adjustment clause by year and by class on a total company and Virginia

[784] The statutory petition requirements direct that 35% of the relevant proposed generating capacity be from the purchase of energy, capacity, and environmental attributes from facilities owned by companies other than Dominion. *See, e.g.*, Code § 56-585.5 D 2 a; *2022 RPS Plan Order* at 14-17.

[785] Tr. at 355 (Flowers), 592 (Ryan).

[786] *2022 RPS Plan Order* at 9 (emphasis in original).

[787] Tr. at 379 (Keefer).

[788] Ex. 49 (Morton rebuttal) at 13; Ex. 22.

[789] For the rate year, the revenue requirement amounts for Peppertown and Alberta are $1.129 million and $0.75 million, respectively. *See, e.g.*, Ex. 36 (Otwell) at Statements 27, 34.

> jurisdictional basis, including all supporting calculations and assumptions. The applicant shall provide such information *by project* if applicable for the specific rate adjustment clause.[790]

In its Petition, Dominion seeks a future and ongoing waiver of the requirement to provide the rate year and annual long-term revenue requirements by project for the Company-owned projects approved in previous phases. As proposed, in future cases Dominion "would provide a rate year and long-term revenue requirement for the CE-1 Solar Projects, a rate year and long-term revenue requirement for the CE-2 Projects and Distributed Solar Projects, and so on."[791] Dominion would continue to show such information, by project, for proposed new projects. For previously approved projects, Dominion would provide project-specific details as needed for review and audit of the proposed revenue requirement through discovery, and would continue to record costs by project in its accounting system where appropriate.[792] The Company indicated that this proposal envisions Rider CE operating like Rider U, which recovers the costs of multiple phases through one rate adjustment clause.[793] Dominion pointed to the fact that this information, for over 30 Company-owned projects and 4 phases, totals 500 pages this year, and the Company anticipates up to 15 phases of projects based on the VCEA's petition requirements through 2035.[794]

Consumer Counsel recommended that Dominion be allowed to provide the revenue requirement calculations by project for all Company-owned projects through the eRoom for a case. However, Dominion's proposal to not create revenue requirement schedules and supporting calculations by project is concerning to Consumer Counsel. Consumer Counsel views the ability to view such information on a project-specific basis as critical for transparency.[795]

Staff ultimately took a position similar to that of Consumer Counsel. Staff would not object to waiver of the requirement to file project-specific revenue requirement information so long as Staff can obtain such information through an eRoom.[796]

I do not recommend the Commission grant the requested waiver as to all previously approved projects. While all Company-owned CE-1 Projects are now operational, most of the CE-2 and CE-3 Projects previously approved by the Commission are not yet constructed and operational. Two of the most expensive CE-2 Projects are not expected to become operational until 2025.[797] The record also shows that some of Dominion's ongoing projects have experienced material cost updates – most notably, the $164.1 million (59%) increase in the projected costs of the Dulles Solar + Storage facility, as discussed above. This recent experience shows that the cost to customers of a project – whether through revenue requirements used to set rates or lifetime revenue requirement calculations – is better understood after a project has been

---

[790] 20 VAC 5-204-90, Schedule 46 c 1 (iv) (emphasis added).
[791] Ex. 3 (Petition) at 23.
[792] *Id. See also* Tr. at 471-83 (Lecky).
[793] Ex. 3 (Petition) at 22.
[794] *Id.*; Tr. at 475 (Lecky).
[795] Tr. at 568-70 (Farmer).
[796] Tr. at 574-75 (Ochsenhirt).
[797] Ex. 11 (Flowers direct) at attached Sched. 2, p. 7 (Sweet Sue Solar and Walnut Solar).

completed. Accordingly, for Company-owned projects, project-specific revenue requirement information should continue to be provided for each phase at least until all of its projects are completed and operational, in my view.

However, I recognize the volume of work associated with by-project revenue requirement calculations and supporting information, which is already sizable and will increase with each proposed project absent any waiver. I also recognize that the cost of solar facilities is largely upfront capital expenditures and ongoing land lease costs established by contract. Additionally, with Dominion's transition to an in-house model, the operations and maintenance of solar facilities will be coordinated and conducted by the Company across its solar fleet. Accordingly, once a solar project is constructed and operating, there should be a relatively low level of project-specific costs that affect revenue requirement. To the extent costs do vary from expected levels, the Rate Case Rules require, among other things, "items supporting the costs that have not been provided in previous applications,"[798] and Dominion has not requested waiver of that requirement.[799]

Based on the record, including the volume of project-specific revenue requirement information and the nature of solar facility costs, I recommend granting a more limited waiver than requested by Dominion. Specifically, I recommend that Dominion be allowed, in its next Rider CE filing, to consolidate its required revenue requirement information for the CE-1 phase – which consists of three Company projects that are all constructed and operational. This limited waiver, if approved, should help inform the Commission as to whether a more expansive waiver is warranted in the future. In addition, given the volume of project-specific revenue requirement information, Dominion should be allowed to post such information in its eRoom.

Risk Information in RFP Reports

Staff raised an issue with the Company's presentation of risk information, including in the RFP reports filed in support of the Petition.[800] Dominion agreed to list in future RFP report summary tables key risks and key risk categories for selected facilities.[801]

VI. 2022 RPS COMPLIANCE

Code – RPS Obligation

The *2020 RPS Plan Order* found that RPS compliance should be considered in the annual RPS plan proceedings.[802]

Code § 56-585.5 C states in part as follows:

[798] 20 VAC 5-204-90, Schedule 46 c 1 (iii) (emphasis added).
[799] Tr. at 473 (Lecky).
[800] *See, e.g.*, Tr. at 252 (Glattfelder).
[801] Tr. at 358 (Flowers).
[802] *2020 RPS Plan Order*, 2021 S.C.C. Ann. Rep. at 245.

The RPS Program requirements shall be a percentage of the total electric energy sold in the previous calendar year and shall be implemented in accordance with the following schedule:

[Dominion]

Year	RPS Program Requirement
2021	14%
2022	17%

Code § 56-585.5 A, in turn, defines "[t]otal electric energy" as follows:

> total electric energy sold to retail customers in the Commonwealth service territory of a Phase I or Phase II Utility, other than [ARBs], by the incumbent electric utility or other retail supplier of electric energy in the previous calendar year, excluding an amount equivalent to the annual percentages of the electric energy that was supplied to such customer [sic] from nuclear generating plants located within the Commonwealth in the previous calendar year, provided such nuclear units were operating by July 1, 2020, or from any zero-carbon electric generating facilities not otherwise RPS eligible sources and placed into service in the Commonwealth after July 1, 2030.

Code § 56-585.5 H states that for any customer of Dominion's "with a peak demand in excess of 100 [MW] in 2019 that elected pursuant to subdivision A 3 of § 56-577 to purchase electric energy from a competitive service provider prior to April 1, 2019, ... such customer's electric load shall not be included in the utility's RPS Program requirements."

Analysis – RPS Obligation

The 2022 Compliance Report provided with Dominion's Petition indicates that the Company retired approximately 9.3 million RECs to comply with the 2022 RPS requirement.[803] The Company showed its calculation of a 9.3 million compliance requirement[804] and the number of RECs retired for 2022 compliance, broken down by resource type, vintage, and location.[805]

Dominion noted that its 2022 Compliance Report calculations do not incorporate the treatment directed by the *RPS Allocation Order* for customers who purchase renewable energy from a competitive service provider.[806] The Commission recently identified this open issue and directed Dominion to address in a separate case: "the proposed treatment of RECs associated with (i) customers taking service under ... voluntary renewable tariffs and (ii) shopping customers purchasing 100 percent renewable energy, for purposes of RPS Program

[803] Ex. 8 (2022 Compliance Report) at 2. Of this amount, 93,176 RECs were retired to comply with the 1% carveout for resources that are one MW nameplate capacity or less. Ex. 8 (2022 Compliance Report) at 4.
[804] Ex. 8 (2022 Compliance Report) at 1.
[805] *Id.* at 4-5.
[806] *Id.* at 1.

compliance."[807] The Commission has set that separate case, referred to by case participants as the "standalone proceeding," for hearing this summer.[808]

Dominion's compliance obligation calculations were updated over the course of this proceeding.[809] As Staff recognized, the Commission cannot finalize its determination of the Company's RPS compliance for calendar year 2022 (or 2021) because of the open issues that will be determined outside of this RPS plan case.[810] However, Dominion and Staff have developed certain issues regarding how to calculate the RPS obligation. Dominion has asserted that some of these issues can and should be addressed in the instant RPS plan proceeding. Those issues are addressed in the four subsections below.

(i) Data Source for RPS Obligation

Dominion requests that the Commission determine that FERC Form 1 is the appropriate data source to use, where possible, in calculating Dominion's annual RPS obligation.[811] Staff also supports using Dominion's FERC Form 1 data.[812] It appears reasonable to use FERC Form 1 data, where possible, provided the underlying information is applicable and accurately reported in its FERC Form 1 by Dominion. To the extent Dominion does not include in its FERC Form 1 data relevant to its RPS obligation calculation – such as distribution sales to shopping customers supplied by competitive service providers[813] – such amounts would need to be obtained from a source other than FERC Form 1.

(ii) VMEA, Micron, and Craig Botetourt

Dominion requests that the Commission determine whether sales to VMEA, Micron, and Craig Botetourt should be included in the "total electric energy sold to retail customers in the Commonwealth service territory of ... [Dominion]."[814] Dominion and Staff appear to agree that Craig Botetourt should not be included in the RPS obligation calculations. I do not see any legal or evidentiary basis for including Craig Botetourt in the calculations. Craig Botetourt is a wholesale customer[815] located outside of Dominion's distribution service territory. Dominion and Staff both recognize that Virginia cooperatives are statutorily exempt from RPS obligations.[816]

---

807 *2023 APCo RPS Plan Order* at 13. While this was an APCo case, Dominion was granted leave to intervene. *Id.*
808 *Petition of Appalachian Power Company, To determine the appropriate treatment of renewable energy certificates associated with certain customers*, Case No. PUR-2024-00009, *Petition of Virginia Electric and Power Company, For determination regarding the treatment of renewable energy customers' renewable energy certificates for purposes of RPS Program compliance*, Case No. PUR-2024-00010, Order for Notice and Hearing (Feb. 5, 2024) (consolidating cases and setting hearing to convene on July 31, 2024).
809 Ex. 61.
810 Ex. 43 (Unger) at 3-4. Dominion further asserted that the Commission is not required to verify compliance with the RPS obligation in the instant proceeding. Ex. 60 at 3.
811 *See, e.g.*, Ex. 29 (Gaskill supplemental direct) at 2; Ex. 60 at 1 (supporting the use of Form 1 data for both retail sales and nuclear output).
812 Ex. 43 (Unger) at 10; Tr. at 328 (Unger).
813 *See, e.g.*, Ex. 58 (Gaskill rebuttal) at 3.
814 Code § 56-585.5 A.
815 Ex. 32.
816 Ex. 43 (Unger) at 24 (citing Code § 56-585.5 J); Ex. 60 at 1.

Staff questioned whether sales to Micron and/or VMEA should be included in the "total electric energy sold to retail customers in the Commonwealth service territory of … [Dominion]." Dominion requests that sales to Micron and VMEA be included, because they are retail and full-requirements customers of Dominion's, respectively, and Dominion has contractual obligations to treat Micron and VMEA like its jurisdictional customers.[817] The provisions of VMEA's full requirements contract with Dominion, as amended in 2009, includes the following statement:

> It is the intent of the Parties that, with respect to … Renewable Energy Credits, and Renewable Energy Portfolio Standards, VMEA will be treated in a manner comparable to, and no less favorable than, the Company's retail load. Accordingly, at either Party's request, the Parties shall negotiate changes to this Agreement to conform or adapt to new federal or state laws, regulations, or programs that materially change the allocation of risk or rights and responsibilities under this Agreement to ensure that VMEA, the VMEA Members, and retail customers of the VMEA Members are treated in a manner comparable to, and no less favorable than, the Company's retail load.[818]

The VMEA full requirements contract, in turn, defines "Renewable Energy Portfolio Standard" to include state RPS obligations enacted in the future (*i.e.*, after 2009).[819]

Dominion explained that the inclusion of VMEA and Micron in the RPS obligation calculation does not affect Virginia jurisdictional rates because sales to these customers are included in the Company's cost allocation.[820] Given its contractual obligations, Dominion expressed concern about not including VMEA and Micron in the Company's RPS obligation calculation. Because jurisdictional customers, VMEA, and Micron all pay their fair share for RPS compliance under Dominion's view, Dominion also would not want a Commission decision that could create arguments about who gets the higher cost RECs used for compliance.[821]

The record is clear that neither Micron nor VMEA is located in Dominion's distribution service territory[822] and VMEA is a wholesale, rather than retail, customer.[823] Accordingly, their sales are not *directly* included in the "total electric energy sold to retail customers in the Commonwealth service territory of … [Dominion]."[824] However, Dominion's position is effectively that the enactment of the mandatory RPS in 2020 triggered *indirect* RPS obligations based on its contractual arrangements with VMEA and Micron, including Dominion's express contractual obligation to treat VMEA like Dominion's retail customers with respect to any future RPS.[825] Dominion's contractual obligation to serve VMEA and Micron was a matter of public

[817] Ex. 60; Ex. 58 (Gaskill rebuttal) at 4-5; Tr. at 529-31 (Gaskill).
[818] Ex. 30 at 2009 Amended Agreement, p. 25.
[819] *Id.* at 14. *See also* Ex. 30; Tr. Day 2 ES Session at 9 (Gaskill) (explaining the nature of the Micron contracts).
[820] Ex. 58 (Gaskill rebuttal) at 5.
[821] Tr. at 532-33 (Gaskill).
[822] Tr. at 529 (Gaskill).
[823] Tr. at 527 (Gaskill).
[824] Code § 56-585.5 A.
[825] The City of Manassas, which had the legal right to serve Micron before allowing Dominion to provide such service under contract, is a VMEA member that executed the 2009 agreement between VMEA and Dominion. Ex. 30 (2009 Amended Agreement) at 62.

record when the VCEA was enacted.[826] And I see nothing in the plain language of the statute that suggests any legislative intent to impede these contracts that were in place at the time of the VCEA's enactment.

It does not appear that VMEA and Micron must be included in the statutory definition of "total electric energy sold to retail customers" for the Commission to recognize, and not impede, Dominion's contractual obligations with these customers. Additionally, while the cost of VMEA and Micron's compliance is included in Dominion's Petition, that cost is offset in jurisdictional rates by including sales to VMEA and Micron in the allocation of these costs.[827] Based on the record, I do not view Commission recognition of contractual RPS obligations with VMEA and/or Micron as problematic in this context. Because any such obligations differ from the purely statutory obligation on Virginia jurisdictional customers, I recommend that the Commission either: (1) allow Dominion to include VMEA and Micron in the RPS obligation total presented in RPS compliance reports, but with an explanatory footnote indicating these contractual obligations are embedded in the total; or (2) allow Dominion to include VMEA and Micron's contractual obligations as separately identified amounts in the RPS compliance reports.

(iii) ARB Offset to the RPS Obligation

Dominion requested a ruling on two issues relating to the statutory offset of ARB sales from the RPS obligation calculation.[828] For the 2022 compliance year, Staff recommended that such sales should be updated, from 6.07 million MWh to 8.49 million MWh, to recognize a Commission order allowing an ARB to include additional RECs for certification.[829] Dominion agreed[830] and I find it reasonable to update this figure. Dominion also recommended that ARB sales figures be taken from the annual Commission-established ARB certification process.[831] I find this approach reasonable, assuming any relevant Commission orders are also recognized, such as the one that prompted the updated figure recommended in the instant case.

(iv) Nuclear Offset to the RPS Obligation

Dominion requested that the Commission decide the percentage to calculate the statutory nuclear offset to the RPS obligation.[832] Staff recommended FERC Form 1 data.[833] Dominion similarly recommended the use of FERC Form 1 data, with the resulting percentage rounded to two decimal places.[834] I find this approach reasonable.

---

[826] The amended VMEA agreement was a public filing with FERC. Ex. 30.

[827] Ex. 59 (Gaskill rebuttal) at 5.

[828] Code § 56-585.5 A ("total electric energy sold to retail customers in the Commonwealth service territory of ... [Dominion], *other than [ARBs]*") (emphasis added).

[829] Ex. 43 (Unger) at 28-29; Tr. at 328-29 (Unger) (citing *Petition of Amazon Energy LLC, For a limited waiver of the Regulations Governing Accelerated Renewable Energy Buyers, 20 VAC 5-319-10 et seq.*, Case No. PUR-2022-00094, Order Granting Waiver (Aug. 12, 2022).

[830] Ex. 60 at 1.

[831] *Id.*

[832] *Id.*

[833] Tr. at 328 (Unger).

[834] Ex. 59 (Gaskill rebuttal) at 6-7.

Dominion requested guidance on how to treat shopping load served by competitive generation providers in the calculation of the statutory nuclear offset percentage. Dominion indicated Code § 56-585.5 A is unclear on this issue and offered a preferred methodology that includes shopping load in the numerator and denominator of the percentage calculation and an alternative that excludes such load.[835] Staff indicated either alternative appears reasonable.[836] The nuclear offset provisions of the statute are emphasized below:

> "Total electric energy" means total electric energy sold to retail customers in the Commonwealth service territory of a Phase I or Phase II Utility, other than [ARBs], by the incumbent electric utility or other retail supplier of electric energy in the previous calendar year, *excluding an amount equivalent to the annual percentages of the electric energy that was supplied to such customer [sic] from nuclear generating plants located within the Commonwealth in the previous calendar year....*[837]

As shown above, the nuclear offset calculation requires a supply percentage based on energy sold. Since Dominion is supplying shopping customers with zero energy, nuclear or otherwise, it appears that zeroing out shopping customers from the nuclear offset calculation would be consistent with Code § 56-585.5 A. Under this approach, shopping load would still be recognized in the "total electric energy sold" amount, as required by the statutory provision shown above, just not in the nuclear offset calculation. However, I note that this recommendation would result in a slightly lower nuclear offset,[838] and therefore a slightly higher RPS obligation, for compliance years 2020 and 2021 compared to Dominion's preferred alternative.

Code – RECs Retired for Compliance

Code § 56-585.5 C states in part as follows:

> For purposes of complying with the RPS Program from 2021 to 2024, ... [Dominion] may use RECs from any renewable energy facility, as defined in § 56-576, provided that such facilities are located in the Commonwealth or are physically located within [PJM]. However, at no time during this period or thereafter may ... [Dominion] use RECs from ... biomass-fired facilities that are outside the Commonwealth.

Code § 56-576, in turn, defines "[r]enewable energy"[839] as follows:

> energy derived from sunlight, wind, falling water, biomass, sustainable or otherwise, (the definitions of which shall be liberally construed), energy from

---

[835] Exs. 59, 59-ES; Tr. Day Two ES-Session 2 at 13-14 (Gaskill).
[836] Tr. at 582 (Ochsenhirt).
[837] Code § 56-585.5 A.
[838] Ex. 59.
[839] This appears to be the definition referenced by Code § 56-585.5 C as Code § 56-576 does not define the term "renewable energy facility."

waste, landfill gas, municipal solid waste, wave motion, tides, and geothermal power, and does not include energy derived from coal, oil, natural gas, or nuclear power. "Renewable energy" also includes the proportion of the thermal or electric energy from a facility that results from the co-firing of biomass. "Renewable energy" does not include waste heat from fossil-fired facilities or electricity generated from pumped storage but includes run-of-river generation from a combined pumped-storage and run-of-river facility.

Analysis – RECs Retired for Compliance

Dominion has asserted that some issues regarding REC eligibility can and should be addressed in the instant RPS plan proceeding. Those issues are addressed in the six subsections below.

(i) Out-of-State Landfill Gas and Black Liquor

Dominion asked for a ruling on whether its retirement of out-of-state landfill gas and black liquor RECs for compliance year 2022 were appropriate. Staff questioned the use of these RECs because out-of-state biomass cannot be used for compliance with the Commonwealth's mandatory RPS and some of the RECs retired by Dominion received a Virginia state certification when the Commonwealth had a voluntary RPS program.[840] Dominion asserted that for 2022 Code § 56-585.5 C allows Dominion to use RECs from any renewable energy facility as defined in Code § 56-576 except, as relevant here, biomass facilities that are outside the Commonwealth. Dominion argued that out-of-state landfill gas and black liquor RECs can be used for compliance because Code § 56-576 lists "energy from waste" and "landfill gas" separate from "biomass" in the definition of "renewable energy."[841]

Based on my reading of Code §§ 56-576 and 56-585.5 C, I agree with Dominion's argument that out-of-state landfill gas falls outside of the biomass exclusion and can be used for RPS compliance for 2022.[842] This appears consistent with the Commission's GATS Business Rules, which list landfill gas RECs as eligible without specifying that such RECs must be generated in Virginia.[843]

However, Dominion represents that black liquor is both (1) "a by-product of pulp from mills that make products from trees" and (2) "'waste' from the paper-making process that is then used to generate energy."[844] In other words, black liquor generation arguably could be considered both energy from waste (allowed) and biomass generation (not allowed, if out-of-state).[845] Last week, the *2024 Business Rules Order* appears to have resolved any such

[840] Ex. 43 (Unger) at 34-36.
[841] Ex. 60 at 2; Ex. 62 (Leimann rebuttal) at 6-7.
[842] This issue involves 54,311 RECs Dominion retired for compliance year 2022. Ex. 62 (Leimann rebuttal) at 7.
[843] *See, e.g., 2021 Business Rules Order.*
[844] Ex. 62 (Leimann rebuttal) at 7. The provisions of Code § 56-585.5 C that identify RPS eligible sources for compliance year 2025 and after do not appear instructive. While those provisions identify "pulping liquor" as a fuel source separate from "biomass," they also identify "pulping liquor" as a type of fuel used at a "biomass-fired facility."
[845] This issue involves 23,747 RECs Dominion retired for compliance year 2022. Ex. 62 (Leimann rebuttal) at 7.

ambiguity by modifying the GATS Business Rules to list as eligible black liquor RECs generated only in Virginia.[846]

(ii) Tire-Derived Fuel

Staff questioned Dominion's retirement of tire-derived fuel RECs for compliance year 2022.[847] While Dominion indicated that these RECs had a state certification number in GATS, the Company acknowledged that tire-derived fuel RECs are listed as non-eligible in the Commission's GATS Business Rules. Dominion concluded that there may not be a basis to use these RECs for RPS Program compliance year 2022.[848] I see no basis for Dominion's purchase or use of tire-derived RECs for 2022 compliance and the Commission's prior guidance on this issue appears clear.[849] The state certification number for these RECs also appears to include "TDF," which is the GATS code for tire-derived fuel.[850]

(iii) Other Biomass Gas in Ohio

Staff questioned Dominion's retirement of other biomass gas RECs generated in Ohio. As discussed above, Code § 56-585.5 C prohibits using out-of-state biomass for compliance years 2021-2024. While Dominion indicated that these RECs had a state certification number in GATS, Dominion recognized that the Commission's GATS Business Rules list as eligible "Biomass – Other Biomass Gases *in VA*."[851] Dominion concluded that there may not be a basis to use these RECs for RPS Program compliance year 2022.[852] I see no basis for Dominion's purchase or use of out-of-state other biomass gas RECs for 2022 compliance and the Commission's prior guidance on this issue appears clear.[853]

(iv) Biomass and Waste Heat Certifications

Staff pointed out that Dominion did not submit timely certifications that the Commission's GATS Business Rules require for biomass and waste heat RECs. Dominion acknowledged this omission, and proposed to submit such certifications after the Commission makes a final determination about the REC requirement for compliance year 2022.[854] Staff found this proposal for delayed certification acceptable.[855] I find this approach is reasonable.

---

[846] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: In the matter of registering and retiring Virginia-eligible renewable energy certificates*, Case No. PUR-2021-00064, Order Revising Business Rules (Feb. 9, 2024) ("*2024 Business Rules Order*").
[847] Ex. 43 (Unger) at 34, 38. This issue involves 23,747 RECs Dominion retired for compliance year 2022. Ex. 62 (Leimann rebuttal) at 7.
[848] Ex. 60 at 2; Ex. 62 (Leimann rebuttal) at 7.
[849] *2021 Business Rules Order* at A-2.
[850] Ex. 43 (Unger) at Attachment No. MBCU – ES Company Responses, p. 12 of 24.
[851] Ex. 62 (Leimann rebuttal) at 8 (emphasis supplied by Mr. Leimann).
[852] Ex. 60 at 2; Ex. 62 (Leimann rebuttal) at 8.
[853] *2021 Business Rules Order* at A-1. This issue involves 649 RECs Dominion retired for compliance year 2022. Ex. 62 (Leimann rebuttal) at 7.
[854] Ex. 62 (Leimann rebuttal) at 8-9.
[855] Tr. at 330-31 (Unger).

(v) Timing of REC Eligibility Determination

Staff and Dominion recognized legislative changes, over time, to the RECs that can be used for compliance. Dominion proposed to address this timing issue by applying the legal definitions in effect at the end of a specific compliance year, and then taking into account the five-year statutory banking window. For example, "for the 2022 compliance year, ... the Company would apply the law as of year-end 2022, and then retire RECs that meet that definition created between 2018 and 2022."[856] Staff acknowledged that this approach deviates from past practice, but that Staff would support this approach if approved by the Commission.[857] I find Dominion's proposed approach reasonable.

(vi) REC Retirement Corrections

Staff identified some RECs that Dominion inadvertently retired instead of banked. In addition, some RECs were retired for the incorrect compliance period. Dominion and Staff agreed that PJM requires a Commission order to fix these errors.[858] Dominion plans to seek such an order to effectuate a one-time update after the final RPS Program compliance obligations for compliance years 2021 and 2022 are determined.[859] I find this proposed approach reasonable.

VII. SOLAR PERFORMANCE

Public witness Tucker raised concerns about the capacity factors achieved by Dominion's operational solar generation facilities and he emphasized the impacts of low or inefficient production.[860] He also provided, among other things, pictures of panels from Dominion's operational Woodland solar station that are out of sync with each other.[861]

Staff also recognized that if Dominion's solar fleet does not generate the expected benefits that customers pay for, customers may have to pay for additional RECs to meet the statutory RPS requirements.[862] Staff recommended that for Dominion's solar fleet, including ring-fenced facilities, the Company be required to include in future RPS plan filings a schedule, per facility, that identifies: both planned and unplanned outages during the previous calendar year, including the actual stop/start dates and times; the corresponding MW of nameplate capacity affected by the outage; corresponding energy sales lost in MWh as a result of the outage; and a brief description of the cause of each outage.[863] Staff also indicated that for energy lost, a directive for the Company to provide such data during discovery (if requested) would be sufficient.[864]

Dominion does not oppose providing certain O&M information for its system solar units

---

[856] Ex. 62 (Leimann rebuttal) at 5-6.
[857] Tr. at 330 (Unger).
[858] Ex. 43 (Unger) at 32-34; Ex. 62 (Leimann rebuttal) at 4.
[859] Ex. 62 (Leimann rebuttal) at 4.
[860] Tr. at 13-37 (Tucker); Ex. 2.
[861] Ex. 2 at second document, pp. 19-27 of 30.
[862] Ex. 40 (Glattfelder) at 43.
[863] *Id.* at 44; Tr. at 250-51 (Glattfelder).
[864] Tr. at 249-50 (Glattfelder).

similar to the information it provides for the Company's nuclear and fossil units in the annual fuel factor proceeding – namely, a schedule showing the planned and unplanned solar unit outages during the previous calendar year, including the start and stop times of the outages, and the reasons for the outages. However, Dominion opposed reporting the nameplate capacity (MW) affected by solar outages and corresponding energy sales lost (MWh) as result of outages. Dominion indicated such information would be burdensome to prepare and is beyond what Dominion reports for other types of units. Dominion also opposed reporting such information for ring-fenced solar facilities, which the Company indicated would be irrelevant to RPS plan proceedings.[865] Dominion believes that capacity factor information, along with the outage information Dominion has agreed to provide, would provide transparency for ratepayers.[866]

The record indicates that Dominion is taking several steps to try to improve the performance of its solar fleet. Such efforts include a spare parts program to mitigate long lead times for parts and components needed for equipment repair and maintenance, an infrared scanning program to detect faulty or underperforming modules and strings during operation by efficiently inspecting hundreds of thousands of pieces of equipment without interfering with day-to-day operations, and the transition from third-party contractor O&M to an in-house solar operations management team for remote operations and electrical maintenance activities.[867]

I recommend that Dominion provide in future RPS plan proceedings outage information comparable to what Dominion provides for its nuclear and fossil units in the fuel factor proceedings. While I do not recommend Dominion provide affected capacity or associated energy lost information, the Company should maintain records sufficient to calculate and provide such information[868] if needed in a future proceeding.[869] I also recommend that Dominion provide in future RPS plan proceedings the capacity factors achieved by solar PPA facilities the Company has under contract.[870] Such information should provide relevant data points for comparison with the capacity factors achieved by Dominion's own facilities.

Finally, I note that the Commission recently initiated a proceeding to determine the appropriate protocols and standards applicable to implementing a performance-based adjustment based on factors that include generating plant performance. The Commission may consider in that proceeding standards for evaluating the performance of Dominion's solar generation facilities for the purpose of determining whether such performance warrants an adjustment to the Company's rate of return.[871]

---

[865] Ex. 51 (Prideaux rebuttal) at 5.

[866] Tr. at 431-32 (Prideaux).

[867] Ex. 51 (Prideaux rebuttal) at 3-4; Tr. at 422-30 (Prideaux); Ex. 52.

[868] I find that such information should focus on Dominion's facilities that have a direct impact on Virginia jurisdictional ratepayers. Accordingly, I do not recommend such information be required for ring-fenced facilities. Tr. at 251 (Glattfelder) (identifying a potential indirect impact on jurisdictional ratepayers from the operation of such facilities).

[869] Such data might be relevant, for example, if a ratemaking disallowance is considered due to issues raised about a specific outage.

[870] The Company's assumptions for such calculations, such as degradation, should be consistent with the assumptions the Company uses to calculate the capacity factors presented for its own facilities.

[871] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia*, Case No. PUR-2023-00210, Order Establishing Proceeding (Dec. 12, 2023).

FINDINGS AND RECOMMENDATIONS

Based on the Code and the record developed in this case, I find that:

2023 RPS Development Plan

(1) Dominion's 2023 RPS Development Plan indicates that, with the Company's instant Petition, the Company has exceeded the interim statutory requirement to petition for 3,000 MW of compliance resources by December 31, 2024, even without consideration of the statutory offset for certified ARB capacity, which reached 1,972 MW as of June 30, 2023.

(2) Dominion's 2023 RPS Development Plan generally appears reasonable and prudent based on the record of this case, giving due consideration to all factors required by Code § 56-585.5 D 4, provided the Company's current development of solar and onshore wind resources is based on factors other than the 2024 interim statutory petition requirement of Code § 56-585.5 D. In addition, given the elevated costs of Dominion's solar projects and PPAs proposed in the instant case, and Dominion's concerns about REC availability, the Company should solicit long-term agreements for unbundled RECs, either by expanding its existing RFP process or through a parallel competitive process.

(3) Dominion should continue to monitor new and developing energy storage technologies and refine its assumptions in future RPS plan and IRP proceedings, as appropriate.

(4) Dominion should continue to explore ways to value location when selecting potential VCEA resources.

(5) Dominion no longer opposes a directive for the Company to upload, at the time of future RPS plan filings, an IRP underlying the RPS plan filing to an eRoom, which would facilitate access to relevant information for participants in RPS plan cases.

(6) Case participants' recommendation for Commission directives from the 2023 IRP Case to be reflected in the Commission's order in the instant case is moot.

CPCNs Requested for Beldale, Blue Ridge, Bookers Mill, and Michaux Solar Projects

(7) No evidence indicates that the addition of Beldale, Blue Ridge, Bookers Mill, or Michaux would have a material adverse effect on reliability. These CE-4 Projects all have executed Interconnection Service Agreements that will obligate these projects to address any identified adverse system reliability impacts.

(8) The VCEA created a need for Beldale, Blue Ridge, Bookers Mill, and Michaux, which would provide RECs that are necessary for RPS compliance, in addition to capacity and energy. Dominion's unprecedented load and peak load growth projections – attributed to additional data center growth – increase the challenges of transforming Dominion's generation fleet without compromising system reliability or affordability.

(9) Pursuant to Code § 56-585.1 A 6, the Commission must consider the social cost of carbon as a benefit in this proceeding. However, Dominion's presentation of economic results in this case blurred the estimated value of its proposed projects to Dominion's ratepayers by combining (i) estimated global benefits to the entire world from estimated carbon reductions with (ii) economic estimates of the benefit/detriment to Dominion's ratepayers.

(10) The economics of Beldale, Blue Ridge, Bookers Mill, and Michaux – even after incorporating the effects of the Inflation Reduction Act – are generally underwhelming for Dominion's ratepayers, although these projects would provide economic development benefits (accruing in part to localities) and these projects would provide a social cost of carbon benefit (accruing to the world). For Beldale, Blue Ridge, and Michaux, Dominion's low-end economic results in the record are significantly negative for Dominion's ratepayers, with the estimated negative net present value of these projects to Dominion's ratepayers exceeding the estimated positive net present value to the world from reduced emissions. Dominion's estimated net present value to its ratepayers is negative for Beldale, Blue Ridge, and Michaux in all three scenarios analyzed by Dominion, although these projects would provide global benefits from reduced emissions. However, for two of the three scenarios analyzed by Dominion, Bookers Mill has an estimated net present value to Dominion's ratepayers that is positive or approaches break-even, in addition to providing global benefits from reduced emissions.

(11) Because Bookers Mill has a DEQ permit by rule, Code §§ 56-580 D, 56-46.1 A, and/or 10.1-1197.8 B preclude environmental review of Bookers Mill by the Commission.

(12) Beldale, Blue Ridge, and Michaux would have some positive environmental impacts, notably on air emissions and water use associated with energy production. These projects would also have some negative environmental impacts, due in part to the acreage and forestland required for their construction.

(13) DCR's recommendation to plant Virginia native pollinator plant species, which has been rejected in prior RPS plan orders, raises cost and statutory anti-duplication concerns.

(14) DCR's recommendation to develop and implement an invasive species management plan, which has been rejected in prior RPS plan orders, raises cost concerns and statutory anti-duplication concerns in the context of a generation CPCN proceeding. However, Commission orders in transmission CPCN cases have directed Dominion to meet with DCR regarding this issue and report on the status of such meetings.

(15) Adoption of DOF's recommendation to mitigate or compensate for negative impacts to trees or forests, which has been rejected in prior RPS plan orders, would increase the costs to ratepayers for projects that are already economically challenged.

(16) DCR-DNH's recommendations to increase the width of certain buffers – which is a matter local governments considered in their reviews and approvals of Beldale, Blue Ridge, and Michaux – raise statutory anti-duplication concerns.

(17) Provided construction of Michaux would not be delayed, it is reasonable for Dominion to provide its construction team with information about plant species identified by DCR-DNH and to coordinate with DCR-DNH if a species of concern is observed within the Michaux project area.

(18) It is reasonable for Dominion to follow applicable guidance, and any requirements, of USFWS and DWR regarding bat survey work in the Blue Ridge project area.

(19) Environmental justice outreach by Dominion and developers has occurred for Beldale, Blue Ridge, and Michaux, and, for some of these projects, may remain ongoing. These projects do not appear to adversely impact relevant environmental justice communities. In addition, Dominion's EPC contract includes provisions for the contractor to use reasonable efforts to maximize the hiring of local residents by subcontractors and vendors.

(20) It is likely that construction of Beldale, Blue Ridge, Bookers Mill, and Michaux would provide some economic development benefits within the Commonwealth, including but not limited to furtherance of the economic and job creation objectives of the Commonwealth Clean Energy Policy set forth in § 45.2-1706.1.

(21) Code § 56-585.1 A 6 deems to be "in the public interest" the construction of solar facilities far in excess of the amounts proposed in this case and prior proceedings.

(22) Based on my weighing of the evidence for Beldale, Blue Ridge, Bookers Mill, and Michaux, their construction is required by the public convenience and necessity. While the record indicates that these projects do not offer a meaningful or cost-effective means of satisfying Dominion's capacity needs, they would reasonably and prudently help satisfy Dominion's RPS compliance and energy needs. However, should the Commission assign greater weight to the economic analysis in this case, the record could support denial of some or all of these projects.

(23) Conditioning CPCN approval on the uncontested DEQ recommendations is desirable or necessary to minimize adverse environmental impact.

PPA Prudence

(24) Based on my assessment of the record, it was prudent for Dominion to execute the CE-4 PPAs and CE-4 Distributed Solar PPAs.

(25) Disaggregated economic analysis and results for each proposed PPA would enable the Commission to review each PPA based on its individual merits.

(26) An avoided cost of REC scenario that blends forecasted market prices and statutory deficiency penalties contributes to a more comprehensive net present value analysis of the system costs and benefits of proposed PPAs and projects.

Consolidation of Riders PPA and CE

(27) Consolidation of Riders PPA and CE is in the interest of judicial economy. To address customer transparency concerns regarding the relative bill impacts of Company-owned resources and third-party owned resources approved for VCEA compliance, the Commission can direct Dominion to provide information on such relative bill impacts in future petitions to revise the consolidated rate adjustment clause.

Proposed Rider CE

(28) The record supports approval of Staff's $135.16 million revenue requirement calculation, except: (a) project-specific revenue requirement(s) would need to be removed if Beldale, Blue Ridge, Bookers Mill, and/or Michaux are denied a CPCN, or if Peppertown and/or Alberta are denied cost recovery; and/or (b) PPA-specific revenue requirement(s) would need to be removed if the Commission determines any of the proposed PPAs are imprudent.

(29) For Peppertown and Alberta, all of the economic results in the record – even after incorporating the effects of the Inflation Reduction Act – are significantly negative for Dominion's ratepayers, indicating that Dominion's ratepayers would be far better off if Dominion pursued other options. While these facilities would provide some economic development benefits and a cost of carbon benefit, economic results in this case indicate that the negative cost to Dominion's ratepayers from these facilities would be approximately two to four times greater than their projected global benefit from reduced carbon emissions. These projects also have high levelized costs of energy and high capacity costs. In addition, most of the identified benefits of Peppertown could have been obtained by accepting prior PPA offers for this facility.

(30) Based on my weighing of the evidence for Peppertown and Alberta, the costs of these facilities are unreasonable and imprudent, and the recovery of such costs would result in an unreasonable increase in the rates paid by Dominion's customers. Denying cost recovery for these projects would lower the revenue requirement in this proceeding by approximately $1.88 million. Should the Commission assign less weight to Dominion's economic analysis in this case, the record could support approving cost recovery for Peppertown and/or Alberta.

(31) Future Rider CE filings should identify the high-end and low-end of potential nameplate capacities, if applicable, for PPAs associated with solar facilities that have not yet completed construction.

(32) Dominion agreed to list in future RFP report summary tables key risks and key risk categories for selected facilities

RPS Compliance

(33) The Commission cannot finalize its determination of Dominion's RPS compliance obligation amounts for calendar year 2021 or 2022 in this case because of open issues that will be determined outside of this case.

(34) Dominion's FERC Form 1 is an appropriate data source to use, where possible, in calculating Dominion's annual RPS obligation, provided the underlying information is applicable and accurately reported by the Company.

(35) Craig Botetourt should not be included in the RPS obligation calculation.

(36) It does not appear that VMEA and Micron must be included in the statutory definition of "total electric energy sold to retail customers" for the Commission to recognize, and not impede, Dominion's contractual obligations with these customers. If Dominion is allowed to embed the obligation of VMEA and Micron in future RPS compliance reports, an explanatory footnote can indicate these customers' contractual obligations are included in the total. Alternatively, the Commission could direct Dominion to include VMEA and Micron's contractual obligation as a separately identified amount in future RPS compliance reports.

(37) The amount of the statutory ARB sale offset to the RPS compliance obligation should be taken from the annual Commission-established ARB certification process and any relevant Commission orders. For the 2022 compliance year, the record supports a statutory offset for certified ARB sales in the amount of 8.49 million MWh for Dominion.

(38) The amount of the statutory nuclear offset to the RPS obligation should be calculated using applicable FERC Form 1 data, with the resulting percentage rounded to two decimal places. Because Dominion is supplying shopping customers with zero generation, nuclear or otherwise, it appears that zeroing out shopping customers from the nuclear offset calculation would be consistent with Code § 56-585.5 A.

(39) Based on Code §§ 56-576 and 56-585.5 C, out-of-state landfill gas RECs fall outside of the statutory exclusion for out-of-state biomass and can be used for RPS compliance for 2022.

(40) The Commission's *2024 Business Rules Order* appears to have determined that out-of-state black liquor RECs cannot be used for RPS compliance for 2022.

(41) Dominion's retirement of tire-derived fuel RECs for compliance year 2022 was inconsistent with the Commission's GATS Business Rules, and unsupported by the Code.

(42) Dominion's retirement of other biomass gas RECs generated in Ohio for compliance year 2022 was inconsistent with the Commission's GATS Business Rules, and unsupported by the Code.

(43) Dominion did not submit timely certifications that the Commission's GATS Business Rules require for biomass and waste heat RECs. It is reasonable to allow Dominion to submit such certifications after the Commission makes a final determination about Dominion's RPS obligation for compliance year 2022.

(44) To determine REC eligibility for a given compliance year, it is reasonable for Dominion to apply the legal definitions in effect at the end of that year, while also taking into account the five-year statutory banking window.

(45) A Commission order is required to address RECs that Dominion inadvertently retired instead of banked and RECs retired for the incorrect compliance period. Dominion plans to request such an order after the RPS obligation amounts for compliance years 2021 and 2022 are determined.

Solar Performance

(46) Outage information for Dominion's solar facilities and PPA capacity factors for solar facilities Dominion has under contract would provide additional information to assess the performance of Dominion's solar facilities in RPS plan proceedings.

Accordingly, **I RECOMMEND THAT** the Commission enter an order that:

(1) ***FINDS***, giving due consideration to all factors required by Code § 56-585.5 D 4, that Dominion's 2023 RPS Development Plan is generally reasonable and prudent based on the record of this case, provided: (i) the Company's current development of solar and onshore wind resources is based on factors other than the 2024 interim statutory petition requirement of Code § 56-585.5 D; and (ii) the Company plans to solicit long-term agreements for unbundled RECs for potential inclusion as part of a RPS compliance portfolio.

(2) ***DIRECTS*** Dominion to solicit long-term agreements for unbundled RECs, either by expanding the Company's existing RFP process or through a parallel competitive process.

(3) ***DIRECTS*** Dominion to continue to monitor new and developing energy storage technologies and refine its assumptions in future RPS plan and IRP proceedings, as appropriate.

(4) ***DIRECTS*** Dominion to continue to explore ways to value location when selecting potential VCEA resources.

(5) ***DIRECTS*** Dominion to upload to an RPS plan eRoom, at the time of future RPS plan filings:

- any recent IRP on which the RPS plan is based; and
- the Excel files underlying the associated IRP appendices.

(6) ***APPROVES*** and ***GRANTS*** CPCNs for Beldale, Blue Ridge, Bookers Mill, and Michaux, subject to the conditions that Dominion:

- comply with the uncontested recommendations of the DEQ Report;
- obtain all environmental permits and approvals necessary to construct and operate these projects; and
- For Michaux, provide Dominion's construction team with information about plant species identified by DCR-DNH and coordinate with DCR-DNH if a species of concern is observed within the project area, so long as project construction would not be delayed.

(7) ***DIRECTS*** Dominion, in future RPS plan petitions accompanied by requests for new projects or PPAs, to separate – and not combine – in its economic analysis, any estimated global social cost of carbon value from the estimated economic value to Dominion's system.

(8) ***ENCOURAGES*** Dominion to continue any ongoing environmental justice outreach.

(9) ***FINDS*** the CE-4 PPAs and CE-4 Distributed Solar PPAs are prudent.

(10) ***DIRECTS*** Dominion to provide, in future PPA prudence petitions, disaggregated economic analysis and results for each proposed PPA.

(11) ***APPROVES*** consolidation of Riders PPA and CE, subject to a requirement for Dominion to provide in future Rider CE petitions information on the bill impacts associated with Company-owned projects/facilities relative to the bill impacts associated with third-party resources.

(12) ***DIRECTS*** Dominion, in future Rider CE filings, to identify the high-end and low-end of potential nameplate capacities, if applicable, for PPAs associated with solar facilities that have not yet completed construction.

(13) ***DIRECTS*** Dominion, in RFP report summary tables for future Rider CE filings, to list key risks and key risk categories for selected facilities.

(14) ***DIRECTS*** Dominion, in future PPA prudence petitions and Rider CE filings proposing new projects, to include net present value analysis with multiple scenarios for valuing the avoided cost of RECs, including a scenario that blends forecasted REC prices and the statutory deficiency penalties.

(15) ***APPROVES*** an updated Rider CE revenue requirement of approximately $133.28 million, subject to the condition that Dominion take all reasonable steps to minimize ratepayer costs, including pursuing federal tax credits that best benefit ratepayers.

(16) ***GRANTS*** a limited waiver of the Rate Case Rules, allowing Dominion, in its next Rider CE filing, to (i) consolidate its required revenue requirement information for the CE-1 phase; and (ii) post project-specific revenue requirement information in its eRoom for that proceeding.

(17) ***APPROVES*** Dominion's use of applicable FERC Form 1 data to calculate its annual RPS obligation, including calculation of the statutory nuclear offset percentage to two decimal places.

(18) ***RECOGNIZES*** Dominion's assertion of RPS obligations associated with its contracts with VMEA and Micron and ***ALLOWS*** Dominion to recognize in its RPS compliance reports any contractual RPS obligation associated with VMEA and Micron either through an explanatory footnote or as a separately identified amount.

(19) ***APPROVES***, for the 2022 RPS compliance year, an ARB offset amount of 8.49 million MWh for Dominion.

(20) ***APPROVES*** Dominion's methodology for a statutory nuclear offset that excludes shopping load.

(21) ***APPROVES*** Dominion's use of out-of-state landfill gas RECs for RPS compliance year 2022.

(22) ***REJECTS*** Dominion's use of tire-derived fuel RECs, out-of-state other biomass RECs, and out-of-state black liquor RECs for RPS compliance year 2022.

(23) ***ALLOWS*** Dominion to submit biomass and waste heat REC certifications after the Commission makes a final determination about Dominion's RPS obligation for compliance year 2022.

(24) ***DETERMINES*** that, to assess REC eligibility for a given compliance year, Dominion may apply the legal definitions at the end of that year, while also taking into account the five-year statutory banking window.

(25) ***DIRECTS*** Dominion to include in future RPS plan petitions: (i) a schedule showing the planned and unplanned solar unit outages during the previous calendar year, including the start and stop times of each outage, and the reasons for each outage; and (ii) annual capacity factors achieved by each operational solar PPA facility the Company has under contract.

COMMENTS

Staff and 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 on this Report must be filed on or before March 1, 2024. 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 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 sent by electronic mail to all counsel of record and any such party not represented by counsel.

Respectfully submitted,

D. Mathias Roussy, Jr.
Senior Hearing Examiner

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, Tyler Building, First Floor, Richmond, VA 23219.

240230001

HEARING EXAMINER'S ATTACHMENT 1

Impact of Consolidated Rider PPA/CE on Residential Bills, as proposed in Petition

	A	B	C (=A*B)	D	E (=C/D)	F
	Va juris rev req	**res. allocation factor**	**res. allocated rev req**	**12 mo kWH forecast**	**consolidated res. rate**	**Impact on 1,000 kWh res. bill**
PPA + CE	$136,676,486	0.63596	$86,921,188	29,449,051,535	$0.00295158	$2.95 PPA + CE Impact

All figures except F are from Company witness Hewett's direct schedule 1, page 8

Relative Impact of Rider PPA vs. Rider CE on Residential Bills

	G	H (=B)	I (= G*H)	J (=D)	K = (I/J)	L
	Va juris rev req	**res. allocation factor**	**res. allocated rev req**	**12 mo kWH forecast**	**standalone res. rates**	**Impact on 1,000 kWh res. bill**
PPA	-$7,419,000	0.63596	-$4,718,209.50	29,449,051,535	-$0.00016022	-$0.16 PPA Impact
CE	$144,095,486	0.63596	$91,639,397.56	29,449,051,535	$0.00311179	$3.11 CE Impact
						$2.95 check - same as F

G for PPA is from Lecky direct sched. 1, p. 2; G for CE is $136,676,486 + $7,419,000 to remove neg PPA rev. req. from CE; H and J are Company figures cited above; the remaining figures are calculated using the formulas shown, consistent with Company witness Hewett's consolidated calculations