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January 19, 2022

BY HAND

Mr. Bernard Logan, Clerk
c/o Document Control Center
State Corporation Commission
P.O. Box 2118
Richmond, Virginia 23218

RE: ***Petition of Virginia Electric and Power Company, For approval of the RPS Development Plan, approval and certification of the proposed CE-2 Solar 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

Dear Mr. Logan:

Enclosed for filing under seal in the above-referenced case, is the Office of the Attorney General's Division of Consumer Counsel Post-Hearing Brief being filed in the above-referenced case. Material deemed Extraordinarily Sensitive by the Applicant is contained in the Post-Hearing Brief. An original and one copy of a redacted version of this filing is also enclosed in accordance with the Commission's Rule 5 VAC 5-20-170.

Yours truly,

/s/ C. Mitch Burton Jr.

C. Mitch Burton Jr.
Assistant Attorney General

Enclosure

cc: Service List

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

PETITION OF

VIRGINIA ELECTRIC AND POWER COMPANY **CASE NO. PUR-2021-00146**

For approval of the RPS Development Plan, approval and certification of the proposed CE-2 Solar 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

**OFFICE OF THE ATTORNEY GENERAL,
DIVISION OF CONSUMER COUNSEL
POST-HEARING BRIEF**

The Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel") hereby submits this Post-Hearing Brief in accordance with the Commission's directive at the conclusion of the evidentiary hearing in this matter.

INTRODUCTION AND SUMMARY

This case represents the second filing made by Virginia Electric and Power Company ("VEPCO" or "Company") in accordance with Va. Code § 56-585.5 D ("Subsection D"), enacted as part of the Virginia Clean Economy Act ("VCEA"). There are multiple requests before the Commission. First, the Commission must determine if the Company's long-term planning for RPS Compliance ("RPS Plan") is reasonable. In the prior RPS proceeding, the Commission established context for what would inform such a finding of reasonableness for this RPS Plan. At a minimum, the Commission directed that future annual filings shall include, among other things, (1) a least cost VCEA plan that meets (i) applicable carbon regulations and (ii) the mandatory RPS Program requirements of the VCEA.

The Company's RPS Plan includes two resource portfolio options – Plan A and Plan B. Plan A generally allows for a resource portfolio that follows least-cost planning principles in meeting the policy goals of the VCEA, without forcing or constraining the modeling. But the Company, the party that put together Plan A, casts doubt on its viability. Plan B does not allow for a resource portfolio that follows least-cost planning principles, and it constrains the modeling to adhere to the capacity targets in § 56-585.5 D. Plan A has a $20 billion dollar value proposition over Plan B. While there may be critiques of Plan A and its viability, there is no evidence suggesting that those critiques can close the $20 billion dollar gap between Plan A and B. There appear to be lower cost options to achieving the net zero carbon goals of the VCEA at a cost to customers lower than what is associated with Plan B.

The Company further seeks various approvals for renewable generation and storage facilities ("CE-2 facilities"), along with associated cost recovery. The requests for approval of the CE-2 facilities can be viewed as the Company's request to implement its preferred Plan B approach, whereby it owns the majority of renewable energy resources developed in accordance with the capacity targets in § 56-585.5 D and -585.1:11.

Requiring electric utilities to transition to net zero carbon emissions will involve significant costs approaching $90 billion.[1] The General Assembly has made the policy decision that Virginia's electric utilities will transition to net zero carbon emissions over the next three decades. As with any long-term utility planning, there are pathways forward that will be higher cost and others that will be lower cost. The Commission, as the economic regulator overseeing this transition, has the authority to ensure that the costs of the transition are reasonable and no

[1] RPS Development Plan at Att. 11.

more than necessary. If the Commission wants to embrace cost saving optionality underlying Plan A for the benefit of customers, the Commission will need to use its authority to send a regulatory signal to the Company that excessively priced projects will not be approved.

ARGUMENT

I. The Commission should require fixes to the Company's RPS Planning.

A. The Company unlawfully demands that the Commission approve a 35/65 PPA-to-self-build ratio.

Subsection D 4 requires the Company's RPS Plan to "reflect, in the aggregate and over its duration, the requirements of subsection D concerning the allocation percentages for construction or purchase of [new solar and onshore wind generation] capacity." Subsection D 2 contains the long-term and interim capacity targets applicable to VEPCO. It states that for purposes of the aggregate (by December 31, 2035) capacity targets,

> [VEPCO] 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 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, which shall include 1,100 megawatts of solar generation of a nameplate capacity not to exceed three megawatts 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 . . . .

The interim targets set forth in Subsection D 2 a, b, c, and d include the similar directive that "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 [VEPCO]."

VEPCO asserts that this language clearly imposes a 65 percent/35 percent split between Company-owned resources and power purchase agreements, respectively. This reading betrays the plain language of the statute. The statute is silent as to what percentage of contemplated resources shall be Company-owned. The statute is clear, however, that 35 percent shall be owned by persons other than VEPCO, which may include VEPCO's affiliates. It complies with the statutory requirement to petition for approval, or plan, for *more than* 35 percent of solar or onshore resources that are from "the purchase of energy, capacity, and environmental attributes from solar facilities owned by persons other than a utility." It would not comply with the statutory requirement for any *less than* 35 percent of such resources to be from third-party purchases. The only statutory language that speaks to the percentage of Company-owned resources is the clause in Subsection D 2 a through d, "with the remainder, in the aggregate, being from construction or acquisition by [VEPCO]." This clause clearly does not attribute a specific percentage to such remainder. Whether the percentage of third-party purchase resources is 35 percent or more than 35 percent, so long as the remainder (which may be less than 65 percent) is Company-owned, the language of this clause is not violated.

Furthermore, even accepting the Company's legal position, Subsection D 2 imposes a requirement *on the Company* with respect to its petitions for approvals of resources. It does *not* impose a requirement *on the Commission* regarding what it must approve. Even if the Company's RPS Plan presented only options that assume a 65/35 percentage split between Company-owned and third-party resources, the Commission is not bound by any language in Subsection D to *approve* resources on the basis of a 65/35 percentage split. And in order for the Commission to have the full breadth of options at its disposal, the Company's planning should present to the Commission options that it may approve, in addition to options the Company may believe meet the requirements imposed on the Company regarding its petitions for approval. The Company's strict adherence to its interpretation needlessly blinds the Commission with respect to alternative RPS compliant plans.

Planning-level analyses need not always be fully compliant with the law. They are just that – planning-level analyses. The Commission is aware of the value of requiring alternative plans that are not necessarily compliant with law, but that provide the Commission with a valid benchmark for comparison purposes.[2] The Company's position that alternatives that do not – in its view – comply with the VCEA should not be presented to the Commission deprives the Commission of valuable information it could use in evaluating the costs and benefits of VCEA-compliant plans.

B. The Company ignores the 25 percent out-of-state flexibility offered by the VCEA's RPS Program.

Section 56-585.5 C ("Subsection C") imposes a new type of geographical requirement, "[b]eginning with the 2025 compliance year and thereafter, [that] at least 75 percent of all RECs used by a Phase II Utility in a compliance period shall come from RPS eligible resources located in the Commonwealth." Until the 2025 compliance year, the statute is silent as to any percentage of RECs that must come from eligible generation resources located in Virginia. This grace period may allow the nascent Virginia REC market time to develop.[3] It is inherent, though, in

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[2] *See Commonwealth of Virginia, ex. rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2018-00065, Final Order at 4-5 (June 27, 2019) ("The Commission requires Dominion and other utilities to include a true least-cost plan in each IRP filing. This plan is necessary to enable the public to know the additional costs of various planning scenarios. While the least-cost plan is sometimes dismissed as 'unrealistic,' it does show the least cost at which a reliable supply of electrical power could be obtained, without the costs of various legislative requirements and the Company's corporate goals. The least-cost plan is a valid benchmark against which to gauge the incremental costs of these public policies and investment goals."), https://scc.virginia.gov/docketsearch/DOCS/4hfb01!.PDF.

[3] Tr. 434 (Dalton).

Subsection C's mandate that, beginning in 2025, the Company may obtain up to 25 percent of RECs for RPS compliance from outside the Commonwealth.

As can be seen in the RPS Plan, however, the Company does not make the most of this flexibility, as the Company plans for none of its RECs from 2027 onward to be obtained from eligible resources outside of Virginia, i.e., areas within PJM.[4] The Company acknowledges the optionality the Code provides to obtain up to 25 percent of its RECs for RPS compliance from outside Virginia beginning in 2025, and agrees the PJM market is a well-developed one (compared to Virginia) that will likely provide less expensive REC purchases and, as a result, a lower cost of complying with the RPS requirements.[5] In other words, by the Company's own admission, the PJM market is one that is likely to provide a less costly REC procurement option. This is a powerful tool for the Company to use to keep costs for customers down while complying with the RPS. Yet the Company not only projects an over-procurement of RECs generally from 2026 through 2040,[6] but in so doing it overstates the quantity of such RECs that it must acquire from eligible resources located only in Virginia.[7] As a result of the Company ignoring flexibility for out-of-state REC purchases as allowed for under the Code, the Company's preferred plan to meet its RPS obligations fails to consider an important tool allowing for more cost-effective RPS compliance.

C. The Company's bill analysis assumes phantom capacity revenues.

Finally, the RPS Plan is inadequate to the extent that the Consolidated Bill Analysis, which is Attachment 10 to the Plan, assumes capacity revenues that will not exist on account of

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[4] Ex. 2/2ES (Petition) at RPS Plan, Attachment 7.

[5] Tr. 184-185 (Compton).

[6] Tr. 283-284 (White); Ex. 26 (White) at 13-14; Ex. 32/32C (Dalton) at 28-29.

[7] Tr. 436-437 (Dalton); Tr. 493-494 (Kuleshova).

the Company's electing the Fixed Resource Requirement ("FRR") in PJM. As stated by Staff witness White, "[t]he Company will no longer receive capacity revenues for the majority of its resources, having elected to participate through the FRR."[8] VEPCO's faulty assumption regarding capacity revenues flows through to the Consolidated Bill Analysis,[9] which Company witness Lecky describes as intended "to capture a lot of moving pieces" with respect to the bill impact of the RPS Plan.[10]

Staff witness White has further confirmed the Company's plan results in significantly overbuilding capacity over the planning period.[11] Staff witness White further stated at the hearing "that the value of additional capacity, once you have satisfied your capacity requirement from an economic standpoint, is zero."[12] It is therefore the case that the capacity offset included in the Company's billing analysis can fairly be described as a phantom capacity offset – it does not exist.

And unlike the billing analysis for RECs, the cost of the capacity offset is not fairly represented in the Company's billing analysis. With respect to RECs, the Company's billing analysis reduces the revenue requirements associated with new offshore wind and solar generation to account for REC values.[13] This REC value is then transferred to Rider RPS. The Company's billing analysis also reduces the revenue requirement associated with new offshore wind and solar generation to account for capacity revenue offsets, equal to projected PJM

[8] Ex. 26 (White) at 7 n.13.

[9] Ex. 2 (Petition) at RPS Plan, Attachment 10.

[10] Tr. 396 (Lecky).

[11] Ex. 26 (White) at 6.

[12] Tr. 278 (White).

[13] RPS Development Plan at Att. 10.

capacity prices. But the Company no longer receives PJM capacity revenue for unit specific capacity. The corresponding capacity charge is not captured in the billing analysis. That is, the billing analysis assumes that a portion of the new renewable generation is free – without any increase in rates. The total amount of capacity revenue assumed over the life of the VCEA supported renewable facilities is significant, approximately $14.9 billion.[14] It is questionable at this time (without any revenue stream) to assume that the $14.9 billion[15] of phantom capacity revenues will actually offset future revenue requirements without any associated rate increase.

Subsection D 4 states: "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." In order for the Commission to make this determination, it must have accurate billing analyses before it. Discounting the costs that customers are likely to pay by including phantom capacity revenues obscures the cost picture for the Commission's consideration and the public's view.

II. The Commission must consider the extent to which the costs of the proposed CE-2 facilities are reasonable.

The Company has proposed approval of the Rider CE-2 facilities, along with associated cost recovery, as a means of implementing its preferred Plan B for RPS compliance. The Company's petition requests necessary approvals for iron-in-the-ground facilities and the associated costs. The Company has proposed to construct, own, and operate 13 utility-scale

[14] RPS Development Plan at Att. 11.

[15] RPS Development Plan at Att. 11.

solar and energy storage projects totaling 731 MWs.[16] Of these 13 utility-scale projects, 150 MWs are associated with hybrid solar and storage facilities and 561 MWs is associated with utility scale solar projects.[17] The capital expense for the CE-2 solar projects is approximately $1.1 billion, excluding financing costs.[18] The capital expense for the CE-2 solar and storage projects is approximately $279.7 million, excluding financing costs.[19] The capital expense for the single CE-2 storage only facility is $41.2 million, excluding financing costs.[20]

The Company proposes to recover the $1.43 billion of Company-owned facilities through a rate adjustment clause, Rider CE.[21] This rate adjustment clause will provide guaranteed dollar-for-dollar cost recovery of the capital and maintenance costs, plus a guaranteed profit equal to the authorized rate of return. The rate adjustment clause will exist to recover these costs over a 35-year period, the projected lifespan of the facilities.

In addition to the Company-owned projects, the Company has requested approval of 24 power purchase agreements ("PPAs") representing 253 MWs of solar generation and 33 MW of energy storage. Six of the solar-only PPAs can be considered utility-scale.[22]

Costs associated with PPAs flow to customers differently as compared to Company-owned facilities. While the specific pricing information is designated by VEPCo as confidential, each PPA has a stated price per MWh. The Company is charged only for each MWh of electricity that is delivered to customers. That is, customers only pay for electricity actually

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[16] Ex. 37/37ES (Kuleshova) at 2.

[17] *Id.* at 9.

[18] *Id.*

[19] *Id.*

[20] *Id.*

[21] Ex. 2/2ES (Petition) at P 26.

[22] *Id.* at P 39.

delivered by the PPAs. Under the RAC-framework, customers pay for the CE-2 projects no matter the performance of the projects, or the actual delivery of electricity.

A. The CE-2 Facilities are not needed to meet native load requirements but can be used to satisfy RPS requirements and energy requirements.

In determining whether to approve the proposed CE-2 projects, it is important for the Commission to bear in mind the "need" underlying the petition for approval. These are not facilities that are needed to meet native load requirements. The Company blurs the actual need for these facilities when it says that, in addition to meeting VCEA requirements, these facilities are needed "to serve customers' capacity and energy needs."[23] As Staff witness Kuleshova states, "without the [VCEA's] mandatory retirements of the fossil units, the Company would have sufficient capacity and would generate sufficient energy to serve its native load requirements, including peaking requirements, going forward."[24] Rather, "the projected capacity gap is primarily driven by VCEA-related retirements of fossil fuel units rather than customer load growth."[25]

It is not clear why the Company wishes to cast the CPCN portion of this case as being about meeting native load requirements *in addition to* the need to comply with the VCEA. What is clear is that, to the extent these facilities are needed, it is wholly a result of the requirements established in the VCEA. The Company is not in danger, without these facilities, of failing to meet customer load. This is an important distinction because, as stated above, the VCEA requires the Company to petition for approval of certain amounts of capacity through certain

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[23] Ex. 10/10ES (Avram Direct) at 12; Ex. 14/14ES (Compton Direct) at 4.

[24] Ex. 37/37ES (Kuleshova) at 7-8.

[25] *Id.* at 8. Staff witness Dalton states that the CE-2 Facilities are needed to serve native load, but clarifies that the "need for additional capacity to serve native load requirements is also a result of the need to comply with the VCEA." Ex. 32/32C (Dalton) at 7.

types of resources, but does not require the Commission to approve such petitions in their entirety. The Commission must rather make a holistic determination of whether the facilities for which approval is sought are reasonable and prudent. And these determinations have important implications for issues such as cost allocation.

Consumer Counsel does acknowledge that these facilities can be used to meet the RPS requirements set forth in § 56-585.5 of the Code of Virginia, as well as the Company's energy requirements. As Staff witness Dalton explained in his pre-filed testimony, the Company is a net-purchaser of energy as of 2022.[26] Mr. Dalton did, however, amend his Figure 4 to show a slightly lesser energy need by taking into account operating license extensions sought by the Company for its Surry and North Anna nuclear facilities.[27] In any event, the Company remains in a net-purchaser of energy position, and it is appropriate in evaluating the need for the CE-2 Facilities to consider their ability to help meet the Company's energy needs in an economic manner.

B. The Company's economic modeling for the CE-2 facilities is flawed.

i. There is a wide range in the levelized cost of energy associated with the proposed CE-2 Company-owned facilities and PPAs.

While the pricing and cost-recovery structure of the PPAs and the Company-owned facilities is different, it is possible to compare the overall costs of the electricity to be delivered by the solar generation on a levelized cost of energy ("LCOE") basis. Company-owned solar projects and PPA solar projects ultimately provide the same product to customers – a kWh of electricity derived from sunlight.[28]

[26] Ex. 32/32C (Dalton) at 11.

[27] Ex. 34 (Revision to Dalton Figure 4).

[28] Tr. 187 (Compton).

In fact, the Company testified that during the RFP process a single solar project can be pitched as a PPA or an asset purchase agreement (i.e., a Company-owned project).[29] As the annual production of electricity can be forecasted over the life of solar facilities, it is possible to discount back the cost of a kWh of electricity expressed in actual dollars. This exercise is useful when comparing alternative solar projects, if cost is a concern during the selection and approval process.

Below is a chart ranking the LCOEs of VEPCO's proposed utility scale CE-2 solar projects and PPAs.[30]

Extraordinarily Sensitive Table		
Utility-Scale Solar Project	LCOE	LCOE Ranking
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[29] Tr. 113 (Avram)

[30] Ex. 37/37ES (Kuleshova) at Extraordinarily Sensitive Attachment KK-1.

And for comparison to the facilities and PPAs proposed in the prior RPS Plan case, the below chart from Staff witness Dalton similarly ranked projects:[31]

Table 5: LCOE of Proposed Resources	
Resource	**Cost ($/MWh)**
Watlington (20-year PPA)	$41.03
Pleasant Hill (20-year PPA)	$41.72
Chesapeake (20-year PPA)	$41.72
Wythe (20-year PPA)	$47.86
Cavalier (20-year PPA)	$52.52
Rivanna (20-year PPA)	$52.97
Grassfield (26% capacity factor)	$72.98
Norge (23% capacity factor)	$83.93
Sycamore (25% capacity factor)	$90.92

ii. The Company's economic analysis inflates the net present value of the Company-owned solar facilities.

The Company's net present value analysis for new generation resources has historically included, among other benefits, a capacity benefit and a REC benefit. These benefits were used as an offset to costs in economic modeling as the Company received actual revenues from third parties in exchange for those products. For capacity, the Company would bid the generation resource into PJM's capacity markets and receive corresponding payments from market buyers. For RECs, before the mandatory RPS Program, the Company could sell the RECs associated with renewable generation and use that revenue to offset the costs of the new generation resource.

[31] Ex. 35 (Dalton 2020 RPS Plan Testimony) at 37.

a. It is "extraordinary"[32] for the Company to assume capacity revenue as an avoided cost input in its economic modeling supporting the CE-2 facilities.

The Company no longer participates in PJM's capacity markets and will not receive capacity revenue for any of the CE-2 facilities.[33] The Company participates in the mandatory RPS Program in which it will retire, and not monetize, the RECs generated by the new generation resources. The Company, however, still includes the assumptions about REC and capacity revenue offsets in its net present value analysis.

It can reasonably be predicted that where a generation facility avoids a future cost that must otherwise be incurred, that an actual benefit to the system is realized. But where no cost is avoided, and no third-party revenue is received, there is no benefit to the system. An unneeded cost cannot also be an avoided cost. Stated differently, a utility realize incur an avoided cost benefit when there is no underlying need to incur the subject cost.

The Company is currently planning to overbuild its capacity requirements by thousands of MWs.[34] The amount of overbuilding (4,000-5,000 MWs), in terms of installed capacity, is equal to the nominal capacity currently provided by the Company's entire nuclear fleet.

With respect to capacity, Staff's position is that there is no organic need for the CE-2 facilities. "Staff believes that the main driver of the capacity need for the CE-2 Projects is subsection B of the VCEA, which requires the retirement of the Company's Virginia-sited fossil fuel generation fleet by 2045."[35] In fact, "without the mandatory retirements of the fossil units,

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[32] Tr. 282 (White).

[33] Ex. 26 (White) at 7 n.13.

[34] Ex. 26 (White) at 6 ("The Company's estimate of its required capacity for VCEA compliance exceeds the PJM reliability requirement net of energy efficiency, through 2036. Figure 3 implies that the Company will have approximately 4,000 – 5,000 MW of excess capacity by the 2036 timeframe.")

[35] Ex. 37/37ES (Kuleshova) at 7.

the Company would have sufficient capacity and would generate sufficient energy to serve its native load requirements, including peaking requirements, going forward."[36]

Beyond long-term needs, the Company does not even have an immediate short-term capacity need for the CE-2 facilities. Staff witness White testified that "[t]he capacity forecasts submitted in this proceeding, taken together with the Company's planned compliance with the VCEA, suggest that the 2021 RPS Projects and PPAs are not needed to serve the Company's capacity requirement in the short term."[37] And the Company at least agrees that there is no capacity need through 2026.[38] While the Commission has indeed recognized need for a facility beyond native capacity obligations, this does not invalidate White's factual conclusion that there is not an organic capacity need for the CE-2 facilities.

The Company's claim to a capacity benefit for the CE-2 facilities carries important implications for both the economic modeling conducted in this case, and the future allocation of costs for any approved resource. It is axiomatic that where there is no capacity need or capacity benefit provided by a CE-2 facility, that no capacity need or capacity benefit can be considered in economic modeling or in cost allocation.

b. It is impossible to avoid a cost of capacity for which there is no need.

The Company's economic modeling supporting the CE-2 facilities continues to assume an "avoided capacity cost" as a benefit. In modeling this benefit, the Company simply assumes that it will continue to receive capacity revenue from PJM as if the Company still participated in the PJM wholesale capacity market.

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

[37] Ex. 26 (White) at 8.

[38] Tr. 713.

At the hearing, Staff witness White demonstrated the fallacy of the Company's position that the CE-2 facilities provide an avoided capacity economic benefit:

> Q: [W]hen the Company plans to have significantly more capacity than it needs, what capacity costs are being avoided?
>
> A: From an economic standpoint, no costs.
>
> Q: You're not avoiding a cost, correct?
>
> A: Yeah, the value of additional capacity, once you have satisfied your capacity requirement from an economic standpoint, *is zero*.[39]

c. The Rider CE-2 Facilities will not receive PJM capacity revenues under the Company's decision to participate in PJM as an FRR entity.

The Company will no longer receive capacity revenues for the majority of its resources, having elected to participate through the FRR alternative in PJM.[40] The Company, however, still uses this revenue stream as an avoided cost input in its economic analyses.[41] The Commission should be skeptical of the Company's economic assumption that it will receive phantom capacity revenues. The bill increases for the CE-2 facilities, charged dollar for dollar to customers through the RAC, will be real, and the Commission should be convinced that any "offsets" to these costs are equally tangible.

d. The Company overstates its ability to sell capacity into PJM, which can carry risk for intermittent generation.

In surrebuttal testimony, Company witness McMillan stated that the "capacity value of the CE-2 projects does not go to zero if the Company's load serving entity capacity obligation is

[39] Tr. 278 (White) (emphasis added).

[40] Ex. 26 (White) at 7 n.13; Ex. 49 (PJM Manual 18) at 219.

[41] Ex. 26 (White) at 7 n.13.

long in a particular year."[42] In support of this statement, McMillan represented that "[w]hile under FRR, the Company is able to sell any excess capacity into the PJM capacity market up to a 1750-megawatt long position. FRR is a five-year election and during that time, we are not projecting to be in excess of 1750 megawatts long."[43]

The rules for how FRR entities operate within the PJM system, including the rules applicable to capacity sales, is addressed by PJM Manual 18. On cross-examination, Mr. McMillan admitted that he was not familiar with which PJM manual contained the rules for FRR entities.[44] Mr. McMillan admitted that he had only a high-level understanding of what an FRR entity can and cannot do with respect to capacity sales in PJM, and that he was not an expert in the area.[45]

At the outset, the FRR alternative allows the Company, subject to certain conditions, to avoid direct participation in PJM's capacity auctions.[46] Rather, the Company must submit a FRR Capacity Plan showing that it can satisfy the unforced capacity obligation for all loads in the FRR service area, including forecasted load growth.[47] By opting out of the PJM capacity auctions, an FRR entity no longer pays the RPM-based Locational Reliability Charge. But the FRR entity no longer receives any auction revenue for capacity that is included in the FRR capacity plan.[48]

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[42] Tr. 744 (McMillan).

[43] *Id.*

[44] Tr. 758 (McMillan).

[45] Tr. 760 (McMillan).

[46] Ex. 49 (PJM Manual 18) at 219.

[47] *Id.*

[48] *Id.*

Mr. McMillan's portrayal of the Company's ability to sell CE-2 capacity is not consistent with the current rules for how an FRR entity may sell excess capacity. First, McMillan's representation that the Company may sell "any excess capacity . . . up to 1750-megawatt long position" ignores the requirement that "to sell capacity resources to a direct or indirect purchaser that may use such a resource in any RPM Auctions or as a replacement resource in RPM, the LSE must also maintain a Threshold Quantity in its FRR Capacity Plan prior to the Delivery Year."[49] That is, the Company must carry an extra capacity reserve of 450 MWs to enable it to make any sale of capacity. If the 450 MWs Threshold Quantity is satisfied, only then the FRR entity may make capacity sales subject to a sales cap "equal to the lesser of (a) [(0.25 * Preliminary Unforced Capacity Obligation or (b) 1300 MW."[50] That is, the most capacity that an FRR entity may sell is limited to 1300 MWs.

Finally using variable generation, such as the CE-2 facilities, in the Company's PJM capacity plan is complicated and faces risks, including the potential for monetary penalties.[51] These risks would extend to the Company's plans to sell capacity as an FRR entity. Due to the risks associated with non-performance of intermittent generation during critical periods, it is unclear from the record how the Company would actually plan to meet its PJM capacity plan obligations and whether it would seek to sell capacity from a CE-2 facility or rather from a non-intermittent generating unit. The amount of capacity that can be sold from a CE-2 facility would not be equal to the nominal amount of capacity, but rather "set equal to the lesser of the units Accredited UCAP or its Capacity Interconnection Rights."[52]

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[49] *Id.* at 224.

[50] *Id.* at 235.

[51] *Id.* at 237.

[52] *Id.* at 227.

In any event, it is of course true that any firm MW included in the capacity plan is fungible and that no sale in excess of the Threshold Quantity would be possible without the existence of all available firm capacity. The Company overstates both its ability to sell capacity as an FRR entity, and the extent to which such sales can be wholly attributed to the CE-2 facilities.

iii. The Company had to triple its price forecast for RECs to make the CE-2 facilities appear economic.

The Company has overstated the avoided cost of RECs that will be needed to comply with the RPS requirements.

Within this one case, the Company presents two different projections for the value of RECs over the planning horizon. For purposes of modeling the RPS Plan, and for calculating the lifetime revenue requirements of the Company-owned CE-2 facilities, the Company uses ICF's forecast for RECs. The Company pays ICF, as its independent expert, to provide commodity forecasts (e.g., natural gas prices and wholesale power prices) and uses these commodity forecasts to complete its planning.[53] The ICF forecast for annual REC prices through year 2060 averages $12.30, and it never exceeds $18 per REC over the relevant lifespan of the CE-2 facilities.

But in justifying approval of the CE-2 facilities, the Company decided to deviate from the "independent" ICF price forecast for future REC prices. To justify the economics of the CE-2 facilities, the Company no longer supports using the ICF forecast for what RECs will cost. Rather, the Company elected to use a dogmatic $45 per MWh "deficiency payment" to value the

[53] Ex. 14/14ES (Compton Direct) at 12 ("The Company contracted with ICF for an independent forecast of future energy, capacity, fuel, and emissions prices for use in evaluating the projects.").

avoided cost of the REC.[54] In other words, rather than assume that needed RECs will cost the amount supported in the RPS Plan, the Company inflates the avoided cost of a REC to the highest possible ceiling. The average REC price assumed over the ICF forecast period is $12.30, which is almost three times lower than the first-year deficiency payment.

If future demand for RECs results in a tight REC market, as claimed by the Company,[55] this increase in demand would be captured by a credible forecast for PJM REC pricing, and the Company has contracted with ICF to provide such a forecast. The Company's claim to a $45 REC value appears to be a collateral attack on the credibility of its own evidence.[56] Moreover, even if the Company is correct that voluntary buyers of RECs will increase demand, those voluntary purchases can still be used to reduce the Company's RPS requirements. Company witness Avram was wrong to suggest that an accelerated renewable energy buyer that voluntarily purchases a REC could not use that REC to offset the Company's annual REC requirements. This is exactly what § 56-585.5 G 1 effectively permits.[57] While such RECs cannot be used for direct compliance with the RPS requirements, such voluntary purchases can be used to reduce the overall calculation of the VEPCO's RPS requirements. This acts to "avoid" a future REC

[54] Ex. 14/14ES (Compton Direct) at 13-14.

[55] Tr. 647 (Avram).

[56] Tr. 647 (Avram).

[57] "[A]n accelerated renewable energy buyer may offset all or a portion of its electric load for purposes of RPS compliance through such arrangements. An accelerated renewable energy buyer shall be exempt from the assignment of non-bypassable RPS compliance costs pursuant to subsection F, with the exception of the costs of an offshore wind generating facility pursuant to § 56-585.1:11, based on the amount of RECs obtained pursuant to this subsection in proportion to the customer's total electric energy consumption, on an annual basis. . . . All RECs associated with contracts entered into by an accelerated renewable energy buyer with the utility, or a person other than the utility, for an RPS Program shall not be credited to the utility's compliance with its RPS requirements, and the *calculation of the utility's RPS Program requirements shall not include the electric load covered by customers certified as accelerated renewable energy buyers*." (Emphasis added).

purchase that would otherwise be necessary. This feature of the law "alleviate[s]" some of the Company's concern about a tight REC market.[58]

The Company's use of dueling REC prices seems grounded in a theory that "you just have to separate the RPS plan from the economic modeling done for the CPCNs."[59] But this is difficult to accept. The purpose of the RPS plan is to inform the pathway forward to implementing compliance with the VCEA. It strains credibility to suggest that one set of economic assumptions should apply in the planning space, but a different set of economic assumptions should apply to implementing the RPS plan. Using different sets of economic assumptions, when it comes time to seek cost recovery of items included in the RPS Plan, harms the credibility of RPS implementation.

a. The Company ignored the Commission's directive to model price sensitivities for RECs.

The Company's insistence that the deficiency payment be used to calculate the REC value in support of the CE-2 facilities is in direct conflict with the Commission's prior directive. In the Company's prior RPS case, the Commission directed that "in order to evaluate subsequent . . . petition requests, such future annual filings shall include *at a minimum* . . . evaluation of RECs from all sources (with both high and low-price sensitivities), including utility-owned, third-party PPAs, and unbundled REC purchases."[60] The Company did not consider unbundled REC purchases as an alternative to its petition to construct the CE-2 facilities. And the Company only used one REC price (the deficiency payment), without considering high and low-price

[58] Tr. 649 (Avram).

[59] Tr. 715 (Compton).

[60] *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, Final Order at 6 (April 30, 2021), https://scc.virginia.gov/docketsearch/DOCS/4%254p01!.PDF.

sensitivities, to support its petition for the CE-2 facilities. And this one REC price is the very highest possible price for a REC – it is the extreme high-end sensitivity case.[61]

The impact of inflating the avoided cost of RECs to the highest possible price is that the economic case for the CE-2 facilities appears better than is likely. Staff witness Kuleshova corrected the NPV analysis using the ICF provided forecast for REC prices.[62] After correcting for the inflated REC values, only three of the Company-owned solar CE-2 facilities are economically viable – Fountain Creek, Solidago, and Walnut.[63] All the other Company-owned solar facilities have negative economic consequences for customers.[64] This is true even after considering the half a billion dollars of benefit that the Company asserts is related to the Social Cost of Carbon.[65]

iv. The Company refuses to consider a viable market alternative for REC procurement.

The Company's economic evaluation of the Company-owned facilities does not compare the costs of the facilities against the next least-cost option. Rather, the economic evaluation seeks to compare the costs of the Company-owned facilities against the costs of the PPAs.[66] The Company did not model the cost of the Company-owned facilities against a market cost for energy, capacity, and RECs.

[61] Ex. 47/47ES (McMillan Rebuttal) at 21 ("If the market does not develop and the REC market is undersupplied, the market clearing price of RECs is likely to become the equivalent of the VCEA imposed deficiency payment in order for supply and demand to be in equilibrium.").

[62] Ex. 37/37ES (Kuleshova) at 16 ("Staff disagrees with using the $45 per MWh deficiency payment as a proxy for either REC values or the avoided cost for CE-2 Projects. Staff recommends that the Company's REC price forecast, prepared by ICF and included in the 2021 IRP Update and the instant filing, be used as a proxy instead. In other words, the avoided cost should be the purchase price of a replacement REC rather than a deficiency payment.")

[63] *Id.*

[64] *Id.*

[65] *Id.*

[66] Ex. 14/14ES (Compton Direct) at 16-17.

The Company's comparison of the costs of the Company-owned facilities against the costs of the PPAs contains a major flaw. In attempting to achieve an "apples-to-apples" comparison of costs, the Company has imposed various phantom costs on the PPAs. First, developers of solar projects that bid their projects as PPAs can take advantage of an Income Tax Credit ("ITC") associated with solar generation.[67] These third-party developers are able to realize the benefit of this ITC upfront, in the first year of operation.[68] This is an economic reality that bidders internalize when they rationalize bidding behavior. If this tax advantage were not available to the developer, the bid price of a PPA project would be higher. Another economic reality is that the Company is not able to take advantage of ITC benefits upfront, as is the case with third-party developers.[69] Rather, the Company must normalize the impact of the ITC over the life of the facility.[70]

Due to the time value of money, the ability to recognize the benefits of the ITC upfront results in a cheaper levelized cost of energy from PPAs as compared to Company-owned facilities recovered through a cost of service. But the Company seeks to "remove[]" this economic reality from its modeling.[71] Different projects will never have the complete same cost dynamics. For example, a project with an enhanced solar profile will produce a cheaper kWh of electricity. It would be inappropriate, and wrong, to diminish one project's enhanced solar profile, as compared to another, for purposes of obtaining an "apples-to-apples" analysis.

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[67] Tr. 110 (Avram).

[68] *Id.*

[69] *Id.*

[70] *Id.*

[71] Ex. 14/14ES (Compton Direct) at 17 ("Comparing the CE-2 Projects to CE-2 PPAs using the market index pricing methodology is also appropriate because it essentially removes the ITC amortization and normalizes the costs over the first 20 years of a project's life.").

Different projects will have different cost characteristics and drivers that will ultimately impact the cost of providing service to customers.

a. Evidence of market alternatives suggests that the CE-2 Facilities are overpriced.

By the objective measures of the market cost of solar generation, as identified by Staff, the cost of the Company-owned projects are expensive. Not **[Begin Extraordinarily Sensitive]** [redacted] **[End Extraordinarily Sensitive]** of the 12 Company-owned projects comes in under the $62.95 per MWh cost estimated by Berkeley Lab.[72] And **[Begin Extraordinarily Sensitive]** [redacted] **[End Extraordinarily Sensitive]** of the costs of the Company-owned projects beings to approach the $41 per MWh estimated by LAZARD.[73]

III. The Commission needs to send a regulatory signal that promotes a lower cost path to VCEA compliance.

a. Consistent with the evidence in this case, a recent report from the Office of the Governor identifies elements of the VCEA that will unnecessarily increase costs.

On January 1, 2022, the Office of the Governor issued a report to the General Assembly addressing (1) how Virginia can achieve 100 percent carbon-free electricity by 2045 at least-cost to ratepayers and (2) a recommendation on "whether the General Assembly should permanently repeal the ability to obtain a certificate of public convenience and necessity (CPCN) for any electric generating unit that emits carbon as a by-product of combusting fuel to generate electricity."[74]

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[72] Ex. 37/37ES (Kuleshova), Extraordinarily Sensitive Attachment KK-1 at 1.

[73] *Id.*

[74] Report of the Virginia Secretary of Natural Resources and Virginia Secretary of Commerce and Trade, Modeling Decarbonization: Report Summary and Policy Brief for Virginia Governor's Office Administration and Policymakers (Chapter 1194, 2020), Senate Document No. 17 (Jan. 1, 2022), https://rga.lis.virginia.gov/Published/2021/SD17/PDF.

A "key conclusion" of the Report includes a finding that "[c]ost reduction pathways are available, mostly centering on effective implementation of the VCEA provisions."[75] There are four "pathways" identified. First, the Report takes aim at the specific capacity targets identified in Va. Code § 56-585.5 D. It finds that these "[s]pecific technology targets in addition to [the RPS] will tend to increase costs to ratepayers."[76] The Report concludes that

> [t]he offshore wind capacity and some of the targeted storage are more expensive than other available options, including the expansion of commercial and residential solar. Eliminating the capacity targets for expanded offshore wind and for electricity storage, and allowing deployment of these resources to be guided by investor decisions about how to meet the RPS and RGGI requirements cost-effectively will likely save money for ratepayers.[77]

For example, simply removing the second offshore wind target and the energy storage targets was estimated to save customers "more than $250 million per year in 2035" and "$450 million per year by 2040[.]"[78]

Second, the Report recognizes that the "cost-effective use of renewable energy has an important geographic component."[79] Currently, the RPS limits VEPCo from using more than 25% of RECs created outside Virginia after 2025. The Report counters that "there may be considerable savings to ratepayers from allowing renewables procurement from other places. An obvious geographic extension for renewables procurement in Virginia is the PJM region, since the supply of electricity across this region is simultaneously determined by PJM operators given

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[75] *Id.* at 3.

[76] *Id.* at 26.

[77] *Id.*

[78] *Id.*

[79] *Id.* at 27.

all of the encompassed generation resources."[80] As an example, the Report compares two models demonstrating the higher cost of a "go-it-alone" approach and concludes "the cost of restricting trade is large, amounting to over $600 million per year in higher costs by 2040, *without any gain in emission reductions*."[81]

Third, the Report finds that cost savings can be achieved if legacy fossil generation is allowed to retire on an economic basis.[82] And "[i]n weighing the costs and benefits of closure, policy makers may want to consider both the local economic effects of shifting generation and the gains in health outcomes resulting from lower fossil fuel combustion."[83]

Fourth, the Report finds that requiring a "go-it-alone" approach to RECs may unduly increase costs associated with land acquisition.[84] To highlight the problem, the Report estimates that five percent of the total land are in Virginia would be required if only in-state renewable resources were allowed to comply with the RPS.[85] This demand for land would result in "increasing prices for land for solar deployment and, potentially, conflicts with other land uses."[86] Again, this point demonstrates the value of having geographic flexibility in RPS compliance.

The Governor's Office seemed to recognize that removing unnecessary constraints would promote a lower cost pathway to achieving the VCEA's goal of net zero carbon emissions. The

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[80] *Id.*

[81] *Id.* at 28 (emphasis in original).

[82] *Id.*

[83] *Id.*

[84] *Id.* at 29.

[85] *Id.*

[86] *Id.*

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Report's findings are consistent the testimony offered in this case highlighting how certain constraints to the Company's RPS modeling unnecessarily increases cost.

In this case, Staff Witness Dalton recommended that the Commission direct the Company to model RPS compliance where the model is free to select only the amount of solar and wind necessary to meet the Company's capacity and REC requirements on an economic basis.[87] This in effect frees the modeling from the forced capacity targets identified in Va. Code § 56-585.5 D. This type of modeling is consistent with the Company's stated desire that it "perhaps as much as any stakeholder, wants to determine a path to clean energy that meets public policy objectives while maintaining the standard of reliability that customers expect and deserve and *doing so at the lowest reasonable cost*."[88]

It is difficult to reconcile the Company's stated desire to achieve net zero carbon emissions at the "lowest reasonable cost" with its opposition to simply considering alternative pathways that may lower costs. The same witness that supports "lowest reasonable cost" clean energy also notes that "the Company generally opposes setting forth alternative plans that do not follow the development targets in the VCEA . . . ."[89] Yet, when asked if VEPCO would consider an alternative where 75% of its REC needs were meet through these lower-cost options, the Company rejected the premise as not "comply[ing] with the VCEA['s] . . . Subsection D."[90] But if the Company is to follow a true "lowest reasonable cost" pathway to net zero carbon emissions by 2045, it must have a plan in place to implement that pathway. If the Commission

[87] Ex. 32/32C (Dalton) at 31.

[88] Ex. 44/44C (Compton Rebuttal) at 26 (emphasis added).

[89] *Id.* at 22.

[90] Tr. 652.

permits the Company to ignore pathways that lower costs for customers, the Commission will miss an opportunity to ensure lower costs for customers.

b. If the Commission wants to avoid an unnecessarily high cost pathway to complying with the VCEA, the Commission should reject unreasonably expensive projects.

Requiring electric utilities to transition to net zero carbon emissions will involve significant costs in the order of tens of billions of dollars. The General Assembly has made the policy decision that Virginia's electric utilities will transition to net zero carbon emissions over the next three decades. As with any long-term utility planning, there are pathways forward that will be higher cost and others that will be lower cost. The Commission, as the economic regulator overseeing this transition, has the authority to ensure that the costs of the transition are reasonable and no more than necessary. And the Commission should use its authority to do so.

Consumer Counsel recommends that the Commission reject cost approval for the five most expensive projects based on LCOE. While the Company has a need to comply with the RPS Requirements, it has not been shown that paying **[Begin Extraordinarily Sensitive]** [redacted] **[End Extraordinarily Sensitive]** the cost of available solar PPA pricing is reasonable. The Company could add the $45 deficiency payment to the LCOE from the **[Begin Extraordinarily Sensitive]** [redacted] **[End Extraordinarily Sensitive]** (which includes rights to energy, capacity, and RECs), and the total price *would still be cheaper* than the LCOE for **[Begin Extraordinarily Sensitive]** [redacted] **[End Extraordinarily Sensitive]**. This is particularly concerning where the Company admits that it has willingly ignored potential lower cost alternatives (i.e., unbundled RECs) to complying with the RPS Requirements.

Finding the CE-2 facilities with an LCOE **[Begin Extraordinarily Sensitive]** [redacted] **[End Extraordinarily Sensitive]** that of available PPA pricing to be unreasonable is consistent with the net present value economic analysis presented in this case. Simply using the Company's own forecast for REC prices used to support the RPS Plan demonstrates that the five most expensive projects will result in net economic harm to customers. This economic harm is only amplified when recognizing that the Company will not receive unit specific capacity payments that it incorrectly assumes in the economic modeling. Rejecting the five most expensive projects will preserve optionality in the future for the Company to pursue projects with better economics and avoid locking in overpriced RPS resources for 35 years. A reasonable path to RPS compliance is not one where projects are approved irrespective of pricing. And in approving cost recovery, the Commission must consider whether the costs of such resources are likely to result in unreasonable increases in rates paid by customers. As long-term planning for RPS compliance approaches full swing, now is an appropriate time for the Commission to signal that cost-effective compliance with the VCEA is a priority.

Extraordinarily Sensitive Table

Utility-Scale Solar Project	LCOE	LCOE Ranking
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

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c. **If the Commission wants to avoid an unnecessarily high cost pathway to complying with the VCEA, the Commission should encourage planning that may promote lower costs of compliance.**

With respect to the RPS Plan, Consumer Counsel is aware that certain parties have joined a stipulation with respect to two models that will be run for the 2022 RPS case. That stipulation does not explicitly require the Company to free the model from the constraint that assumes that 65 percent of the Subsection D capacity targets will be developed, approved, and owned by the Company. Rather, it acknowledges that the Company intends to continue to assume a requirement of 65 percent utility owned and 35 percent third party owned resources absent any Commission direction to the contrary. The evidence in this case, and the prior RPS case, is that the LCOE from Company-owned solar projects is significantly higher than the LCOE from solar PPAs.

VEPCO has taken a legal based position that it will not model a VCEA compliant future without the assumption that the Company construct and own 65 percent of the capacity targets identified in Subsection D of § 56-585.5. Other parties have taken a legal position that the law does not require such a constraint. Irrespective of the legal issue, Consumer Counsel recommends that the Commission order the Company to model an alternative that removes the forced assumption that the Company must construct and own 65% of the capacity targets identified in Subsection D of § 56-585.5. There is value in knowing the cost differential between a VCEA compliant future that has this constraint and an alternative future that does not have this constraint. Even taking for granted the Company's legal position, the Commission has the authority to direct modeling of scenarios that do not necessarily comply with the law, as is demonstrated by the requirement that the Company model Plan A in this case. Thus, while Consumer Counsel does not oppose the individual modeling terms contained in the stipulation, Consumer Counsel would object to a directive on modeling that did not require removal of this constraint. 22012013 4

CONCLUSION

Consumer Counsel respectfully requests that the Commission adopt the positions and recommendations stated herein and identified in the attached issue matrix.

CONSUMER COUNSEL ISSUE MATRIX

1. The Commission should direct the Company to remove the assumed "requirement of 65% utility owned and 35% third party resources" from the modeling scenario identified in Paragraph 1.b. of the Proposed Partial Stipulation and Recommendation.
2. The Commission should direct VEPCO to correct the RPS Plan's consolidated billing analysis to properly reflect the Company's election to forego unit-specific capacity revenues as an FRR entity.
3. As detailed in the ES LCOE chart above (p. 29), the Commission should not approve cost recovery of Company-owned solar projects that would result in unreasonable cost burdens for customers as compared to available PPA options.

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing was served on January 19, 2022, by electronic service, to:

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