COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PREFILED STAFF TESTIMONY

VIRGINIA ELECTRIC AND POWER COMPANY

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

April 18, 2019

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PART A

Summary of the Testimony of Earnest J. White

Staff evaluated Virginia Electric and Power Company's ("Company") 2018 Corrected IRP for compliance with the Commission's December 7, 2018 Order ("2018 Order"). Primarily, my testimony addresses the Company's efforts to comply with a reevaluation of its capacity need using Staff's recommended methodology. Staff believes that the Company's forecast methodology reasonably approximates that recommended by Staff. I will discuss, at a high level, the Company's assertions of its modeling limitations. Staff recommends that the Company make use of the new interim between IRP filings to continue to investigate its forecasting software and models. Further, Staff recommends that the PJM Dominion Zone coincident peak forecast be the baseline from which the Company evaluates its capacity need in future IRPs.

The Company also was ordered to model demand-side management ("DSM") as mandated by the Senate Bill 966 ("SB 966"). The Company complied with this directive by quantifying an approximate 200 megawatt decrease to its capacity forecast and an approximate 1,500 gigawatt-hour decrease to its energy forecast. The Company modeled these approximate capacity and energy values both as supply-side and demand-side options, as the Commission ordered. Staff recommends that the Company continue to model this mandate until such time as the mandate expires or is satisfied. The Company should also, as it did in this filing, model existing programs, programs proposed under the SB 966 mandate, and use its judgement to meet the remainder of the mandated $870 million in DSM-related programs required to be proposed by SB 966.

The final areas of the Company's 2018 Corrected IRP that I evaluated are related to the Company's proposed solar photovoltaic ("Solar PV") generating resources. The 2018 Order stated that the Company is to evaluate its future Solar PV resources assuming a capacity factor of 23 percent. The Company complied with this directive. In selecting the 23 percent capacity factor, the Commission stated in the 2018 Order that it weighed evidence regarding the causes of the actual solar capacity factors and evidence supporting technological efficiency improvements of solar resources over time. Staff recommends that the Company continue to use a performance-weighted capacity factor in evaluating its future Solar PV resources. Staff believes that such a methodology will appropriately balance the performance that the Company expects and the performance that the Company is achieving.

The 2018 Order found the Company's renewable energy certificate ("REC") price forecasting methodology to be unreasonable. The Commission ordered the Company to evaluate REC prices by incorporating actual historic REC prices. While the Company used the REC price forecast that the Commission found to unreasonable, as its starting point, the Company made some adjustments based on historic REC prices. Staff recommends that the Company use a statistical method based on historic REC prices as its starting point in future IRPs. From that point, the Company should then consider sensitivities evaluating both market risk and policy risk to REC prices. Staff believes this will better evaluate the risk ratepayers face should REC prices not materialize as the Company projects.

PREFILED TESTIMONY
OF
EARNEST J. WHITE

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUR-2018-00065

April 18, 2019

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE STATE CORPORATION COMMISSION ("COMMISSION").

A1. My name is Earnest White. I am a Senior Utilities Analyst with the Commission's Division of Public Utility Regulation.

Q2. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY IN THE CURRENT PROCEEDING.

A2. On May 1, 2018, Virginia Electric and Power Company ("Company" or "Dominion") filed its 2018 Integrated Resource Plan ("2018 IRP") pursuant to § 56-597 of the Code of Virginia ("Code"). Beginning on September 24, 2018 the Commission convened a hearing on the Company's 2018 IRP. This hearing concluded on September 27, 2018. On December 7, 2018, the Commission issued an Order, stating its opinion and findings in the 2018 IRP proceeding.[1]

In its 2018 Order, the Commission determined that the Company failed to establish that its 2018 IRP, as filed, was reasonable and in the public interest.[2] The 2018 Order found that the Company's 2018 IRP failed to comply with the Commission's Order issued

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[1] *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, Order (Dec. 7, 2018) ("2018 Order").
[2] *Id.* at 2-3.

on the Company's 2017 IRP.[3] The Commission further found that the Company was to correct and refile its 2018 IRP subject to the provisions of the 2018 Order.[4] On March 7, 2019, the Company filed its corrections to its 2018 IRP ("2018 Corrected IRP"). My testimony will address the 2018 Corrected IRP and the Company's assertions of compliance with the 2018 Order.

Q3. PLEASE SUMMARIZE THE AREAS WHERE THE COMMISSION FOUND THAT THE COMPANY DID NOT COMPLY WITH THE ORDER ISSUED IN THE 2017 IRP.

A3. In the 2017 Order, the Commission took judicial notice of Senate Bill 966 ("SB 966") and its necessary impacts on future IRPs.[5] The 2017 Order directed the Company to model the new mandates contained in SB 966.[6] The Commission noted in its 2018 Order:

> With respect to the requirement to address the mandates contained in Senate Bill 966, the record reflects that the Company included some, but not all, of those mandates in its 2018 IRP.[7]

The Commission found that the Company did include the Coastal Virginia Offshore Wind project ("CVOW") and modeled solar photovoltaic ("Solar PV") resources including and in excess of the amounts contemplated by SB 966.[8] However, the Commission also found that the Company did not model the amount of energy efficiency programs at a level contemplated by SB 966, nor did the Company model a battery storage pilot as required by SB 966.[9] Additionally, the 2018 IRP did not include costs associated with the Strategic

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[3] 2018 Order at 4-5.
[4] *Id.* at 5.
[5] *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-2017-00051, Order (Mar. 12, 2017) ("2017 Order") at 3.
[6] *Id.* at 3-4.
[7] 2018 Order at 4.
[8] *Id.*
[9] *Id.*

Undergrounding Pilot, the Grid Transformation Plan, or the Transmission Line Undergrounding Pilot.[10]

As well, the 2017 Order directed the Company to model all other legal requirements contained in the Code, primarily the utility's least-cost plan as well as plans compliant with proposed federal carbon-control regulations.[11] The Commission noted in its 2018 Order:

> The record in the instant proceeding reflects that the Company's least-cost plan includes resources, such as the [CVOW] demonstration project, that were not selected by the Company's modeling on a least-cost basis, but rather were forced into each of the Company's alternative plans. The record also reflects that the Company's modeling was not permitted to select certain highly-efficient natural gas-fired combined-cycle facilities for purposes of developing a least-cost plan.[12]

Based on the foregoing, the Commission found that the Company's 2018 IRP neither complied with the 2017 Order nor established that the 2018 IRP was reasonable and in the public interest.[13]

Q4. PLEASE SUMMARIZE THE GUIDANCE THAT THE COMMISSION PROVIDED TO THE COMPANY TO ADDRESS THE ABOVE FINDINGS.

A4. The 2018 Order required that the Company submit a least-cost plan that neither forced the modeling of any particular resource, nor excluded any reasonable resource.[14] The Commission stated that this requirement:

> [D]oes not reflect any finding that the Company should pursue any specific resource included in the least-cost plan; rather, as the Commission has repeatedly recognized, the IRP is a planning document, and it is reasonable, for planning purposes, to identify the least-cost plan to provide a benchmark against which to measure the costs of other alternative plans.[15]

[10] 2018 Order at 4.
[11] 2017 Order at 3.
[12] 2018 Order at 3-4.
[13] *Id.* at 4.
[14] *Id.* at 5.
[15] *Id.*

Additionally, the 2018 Order required the Company to calculate the incremental costs impacts of the mandates contained in SB 966, including a comparison to the least-cost plan. The Commission explains:

> This includes CVOW; 5,000 MW[16] of nameplate wind and solar, including at least 25 percent of such resources from non-utility generators; $870 million in spending on energy efficiency programs; the 30 MW battery storage pilot; the [Strategic Undergrounding Pilot]; the Grid Transformation Plan; and the Transmission Line Undergrounding Pilot.[17]

The Commission recognized that an IRP is a planning document and does not approve any specific expenditure.[18] However, the Commission further stated that, "... [L]egally-mandated costs are likely to be borne by customers in one form or another, so it is essential that an IRP provide the public and policymakers with projected costs for such mandates that are as accurate as possible."[19]

Q5. DID THE COMMISSION'S 2018 ORDER ADDRESS THE REASONABLENESS OF OTHER ASPECTS OF THE COMPANY'S 2018 IRP?

A5. Yes. The 2018 Order expressed "considerable doubt" in the reasonableness of the Company's load forecast for use of predicting future energy and peak load requirements.[20] The Commission also found that the Company should consider a lower capacity factor for its future Solar PV facilities.[21] Finally, the Company's methodology for forecasting renewable energy certificate ("REC") prices was found to be unreasonable.[22]

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[16] Megawatts.
[17] 2018 Order at 5.
[18] *Id.* at 6.
[19] *Id.*
[20] *Id.* at 7.
[21] *Id.* at 9.
[22] *Id.*

Q6. PLEASE STATE THE SPECIFIC AREAS OF THE COMPANY'S 2018 CORRECTED IRP THAT YOU WILL BE ADDRESSING IN YOUR TESTIMONY.

A6. My testimony will primarily focus on the Company's compliance with the Commission's directives regarding the reasonableness of its load and energy forecasts. I will also address the Company's modeling of Solar PV capacity factors for its future facilities. Lastly, I will comment on the Company's compliance with the Commission's directives regarding the reasonableness of its REC price forecast. Staff witnesses Greg Abbott and Carol Myers will discuss the balance of the issues. I will indicate where our testimonies overlap, as well.

<u>Load Forecast</u>

Q7. PLEASE SUMMARIZE THE COMMISSION'S DIRECTIVES REGARDING THE COMPANY'S LOAD FORECAST IN THE 2018 ORDER.

A7. The Commission's 2018 Order stated that for the purposes of the Corrected IRP:

> [T]he Company shall utilize the Dominion Zone PJM[23] coincident peak load forecast and energy sales forecast, scaled down to the Dominion load serving entity level, consistent with the methodology presented by Staff witness White...[24]

Further the Commission directed that:

> In order to assess more fully the impact of the requirement of Senate Bill 966 that the Company propose $870 million in spending on new energy efficiency programs by 2028, the Company shall also model the impact of that requirement on the load forecast in all plans other than the least cost plan.[25]

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[23] PJM Interconnect, L.L.C

[24] 2018 Order at 8.

[25] *Id.*

Q8. HAS THE COMPANY COMPLIED WITH THE COMMISSION'S DIRECTIVE TO USE THE SPECIFIC FORECASTS AND METHODOLOGY THAT YOU RECOMMENDED IN YOUR DIRECT TESTIMONY IN THE 2018 IRP HEARING?

A8. The Company asserts that it complied with the Commission's directives to the best of its ability.[26] Staff agrees that the Company has made a good faith effort to comply with the 2018 Order. The Company states that due to the limitations of its modeling software the Company had to approximate the forecasts identified in the 2018 Order.[27] After reviewing the Company's load forecast, for the purposes of the 2018 Corrected IRP, the Company's re-filed load forecast does reasonably approximate the methodology directed by the 2018 Order. Additionally, the Company is in compliance with regards to the use of the energy sales forecast, as directed by the Commission. However, here the Company's modeling limitations must be considered.

Q9. COULD YOU FURTHER EXPLAIN THE COMPANY'S LIMITATIONS MODELING THE PJM'S FORECAST?

A9. My understanding of the Company's methodology, as explained in the 2018 Corrected IRP, is that the Company can present its reliability requirement[28] based on PJM's coincident peak forecast; however, the Company cannot incorporate the PJM forecasts on an energy basis without further modification.[29] Both the peak and energy forecasts provided by PJM

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[26] 2018 Corrected IRP at 2.
[27] *Id.* at 12.
[28] The Company's share of the projected capacity that it must procure to ensure reliability within the greater PJM system.
[29] 2018 Corrected IRP at 12.

are annual data points. However, hourly values across the entire year are required in order to forecast energy sales. As such, it is my understanding that the Company used PJM's energy forecast but used its internally-produced load shape to derive a data set comprised of all 8,760 hours across the year.[30] For the purposes of the 2018 Corrected IRP this produces a result that reasonably approximates PJM's forecast. The difference between Staff's reserve requirement projection in the 2018 IRP and the Company's reserve requirement projection in the 2018 Corrected IRP is now de minimis.[31] Staff witness Abbott will discuss the effect of this reduction in the Company's expected reserve requirement on the Company's least-cost plan.

DOM LSE Reserve Requirement			
Year	Staff 2018 IRP (MW)	Company 2018 Corrected IRP (MW)	Difference (%)
2019	19,351	19,339	0.06
2020	19,402	19,379	0.12
2021	19,572	19,548	0.12
2022	19,755	19,739	0.08
2023	19,887	19,841	0.23
2024	19,990	19,973	0.09
2025	20,138	20,128	0.05
2026	20,285	20,267	0.09
2027	20,472	20,451	0.10
2028	20,684	20,651	0.16
2029	20,876	20,825	0.25
2030	21,034	21,017	0.08
2031	21,191	21,200	0.04
2032	21,374	21,370	0.02
2033	21,533	21,551	0.08

[30] 2018 Corrected IRP at 12.

[31] The greatest absolute percent difference is now approximately two-tenths of one percent.

Q10. THE COMMISSION ALSO DIRECTED THE COMPANY TO MODEL THE MANDATED $870 MILLION IN PROPOSED ENERGY EFFICIENCY PROGRAMS, DID THE COMPANY COMPLY WITH THIS DIRECTIVE?

A10. Yes. The Company projected approximately 200 MW and 1,500 gigawatt-hours ("GWh") of demand-side management ("DSM"), in its 2018 Corrected IRP.[32] The Company modeled this as both a supply-side resource, or as if it were a generating unit;[33] the Company also modeled this as a demand-side resource, or as a reduction to its load and energy forecasts.[34] The Company states that both the 200 MW and 1,500 GWh estimates contain DSM which already exists, that was proposed in Case No. PUR-2018-00168, and used generic assumptions to fill in the remainder of the required $870 million DSM spend mandated by the SB 966.[35] Staff believes that the Company has complied with the directive to model its legally-mandated DSM-related proposals as both a reduction to its load forecast and alongside its other supply-side resources. Staff witness Abbott discusses the effects of the Company's DSM modeling assumptions on the Company's least-cost plan.

__Solar PV Capacity Factors__

Q11. PLEASE SUMMARIZE THE COMMISSION'S DIRECTIVE REGARDING SOLAR PV CAPACITY FACTORS.

A11. The 2018 Order directed that:

[32] 2018 Corrected IRP at 8-9.
[33] *Id.* at 7.
[34] *Id.* at 6.
[35] *Id.* at 4-5.

> For the purposes of the Company's corrected 2018 IRP, the Commission finds that the Company should model a 23 percent capacity factor for solar PV resources.[36]

In selecting the 23 percent capacity factor, the Commission stated in the 2018 Order that it weighed evidence regarding the causes of the actual solar capacity factors and evidence supporting technological efficiency improvements of solar resources over time.[37]

Q12. DO YOU HAVE ANY COMMENTS REGARDING THE CAPACITY FACTORS OF THE COMPANY'S EXISTING SOLAR PV UNITS?

A12. Yes. In Case No. PUR-2018-00101, the Company stated that it expects to bid its Solar PV resources into the PJM capacity market at a capacity factor of 23 percent.[38] In the 2018 IRP, the Company modeled its generic Solar PV facilities at a capacity factor of 25 percent.[39] Lastly, in the US-3 Proceeding, a 28 percent design capacity factor was projected.[40]

However, it appears that the Company's Solar PV facilities have achieved a capacity factor closer to 20 percent.[41] Staff witness Abbott focuses on the actual performance of the Solar PV generating units in his testimony.

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[36] 2018 Order at 9.
[37] *Id.*
[38] *Petition of Virginia Electric and Power Company, For approval and certification of the proposed US-3 Solar Projects pursuant to §§ 56-580 D and 56.46.1 of the Code of Virginia, and for approval of a rate adjustment clause, designated Rider US-3, under § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2018-00101. ("US-3 Proceeding"). Exhibit 4 at 19.
[39] 2018 IRP at 167.
[40] US-3 Proceeding, Exhibit 12 at 5.
[41] *See* Staff Attachment EJW-1. Company's response to Staff Interrogatory No. 19-177.

Q13. DID THE COMPANY MODEL THE CAPACITY FACTOR OF ITS FUTURE SOLAR PV RESOURCES AT A CAPACITY FACTOR OF 23 PERCENT?

A13. Yes. The Company states that it modeled its future Solar PV resources at a capacity factor of 23 percent.[42] Staff believes this to be an appropriate planning figure that balances the value at which the Company expects its units to perform over the Planning Period[43] and the observed performance of the Company's current fleet of Solar PV generating units.

<u>**REC Prices**</u>

Q14. PLEASE SUMMARIZE THE COMMISSION'S DIRECTIVE REGARDING THE COMPANY'S REC PRICE FORECASTING METHODOLOGY.

A14. The 2018 Order directed that:

> For purposes of the corrected 2018 IRP filing, the Company shall present an alternative methodology for forecasting REC prices that incorporates actual observable market prices for RECs.[44]

Q15. DID THE COMPANY COMPLY WITH THIS DIRECTIVE?

A15. In the 2018 Corrected IRP, the Company asserts that it modeled an alternative methodology that "incorporates actual observed prices for RECs."[45] The Company asserts that its methodology benchmarks fundamental forecasts of REC prices to actual market prices to account for the economic imperfections in REC markets, such as illiquidity, imperfect information, and surplus capacity.[46]

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[42] 2018 Corrected IRP at 4.
[43] 2019-2033.
[44] 2018 Order at 10.
[45] 2018 Corrected IRP at 17. *See* Staff Attachment EJW-2. Company's response to Staff Interrogatory No. 19-172(b).
[46] 2018 Corrected IRP at 17.

Q16. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S ALTERNATIVE METHODOLOGY.

A16. The Company's alternative methodology is still tied to its original methodology.[47] That is to say that the Company did not produce a fundamentals forecast based on the supply and demand for RECs in the market. Rather, as in the 2018 IRP, the Company first calculated the price of RECs as the residual value needed to make its resources whole net of energy and capacity revenues that the units are projected to receive in PJM's markets. The Company added a second step that it asserts takes into account the difference between the prices required for cost recovery and the actual prices received in the market, historically.[48] The Company referred to this second step as discounting in the 2018 Corrected IRP filing. The Company asserted that this discounting was applied in "all years in which projected prices exceed an anticipated price floor reflective of administrative cost."[49]

Q17. DO YOU HAVE SUGGESTIONS THAT THE COMPANY SHOULD CONSIDER IN FUTURE IRPS?

A17. Yes. Broadly speaking, Staff does not believe that there is much useful information in a point estimate of a future REC price. Staff believes that once the Company has produced a forecast based on actual historic REC prices, the Company should then build varying REC price scenarios and model run sensitivities. In addition, if the Company is aware of risks, such as the closure of certain REC markets, it should provide sensitivity model runs accounting for that risk and the impact to the Company's plans. Staff recognizes the limited

[47] 2018 Corrected IRP at 17.
[48] *Id.*
[49] *Id.*

timeframe to prepare the 2018 Corrected IRP. However, in future IRPs, the Company should take efforts to better model the *risk* associated with REC prices rather than REC prices themselves. In Staff's opinion, fundamentals forecasting does not lend itself to forward REC prices.

By incorporating historic prices, and using sensitivity testing, the Company can produce forecasts that consider the *risk* should the Company not realize a REC price required for cost recovery. The Company's resources are made whole through rates. Thus, the real question is not how much REC revenue the Company *needs* to receive. Rather the questions to consider in planning are: to what degree are ratepayers exposed should REC revenue fail to materialize? Additionally, how would such a shortfall in REC revenue affect the Company's build plans?[50]

<u>Recommendations</u>

Q18. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A18. Given that the Company's next IRP filing will be filed in 2020, and then spaced three years apart, Staff has made recommendations for the Company to consider prior to its 2020 IRP filing. Regarding the Company's load and energy forecasts, Staff recommends that in future IRPs the Company's baseline peak and energy forecasts be derived from the most recently available PJM coincident peak and energy sales forecasts, in the same manner as it has been derived in the 2018 Corrected IRP. The PJM coincident peak forecast is the basis on which the Company's ultimate capacity obligation will be set. Thus, this is the

[50] Staff recognizes REC prices above those required for cost recovery might also affect the Company's build plans.

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logical place to start. In addition, PJM's load forecasting process has generally been transparent, and its data and results are posted publicly.

The Company could still present its internal forecast as a sensitivity. Staff would consider any verifiable evidence that the Company presents based on its internal forecasts. Ultimately, it is Staff's opinion that the Company should plan to procure adequate capacity to meet its capacity obligation as a member of PJM.[51] Thus, accurate forecasts of this obligation are the reasonable standard on which the Company should plan its resource requirements. PJM's forecasts are not perfect. However, the Company's obligation to meet its capacity obligation as determined by PJM cannot be debated.

Additionally, the Company should continue to incorporate the capacity value of the legally-mandated DSM proposals into its load forecast. As well, the Company should incorporate the energy value of the legally-mandated DSM proposals into its energy sales forecast. Lastly, Staff recommends that the Company continue to investigate its load and energy forecasting software, models, and methodologies in the interim to ensure that they remain current and reasonable. Staff recognizes the short timeframe for filing the 2018 Corrected IRP; however, prior to filing future IRPs, the Company should consider such an undertaking.

Regarding Solar PV capacity factors, in future IRPs, the Company should continue to model Solar PV resources with a performance-weighted capacity factor, as may be directed by the Commission.[52] As an example, should the Commission choose to formalize this approach in a generic sense, the Commission may consider a projected Solar

[51] *See* Staff Attachment EJW-3, *Application for membership in the regional transmission organization known as PJM Interconnection, LLC,* Case No. PUE-20003-00284.
[52] The 2018 Order directed the Company to model a capacity factor of 23 percent which balances the current expected capacity factors with the current actual observed performance of the Company's Solar PV units.

PV capacity factor weighted by the design capacity factor of the Company's future Solar PV units and by the three-year average performance capacity factor of the Company's existing Solar PV units. An additional formulation that the Commission may consider would be weighting the projected capacity factor by the expected PJM firm capacity of the Company's future Solar PV units and the three-year average performance capacity factor of the Company's existing Solar PV units.

The Company's current Solar PV units have not yet achieved the Company's projected capacity factors, on an annual average basis. Thus, Staff believes that a performance-weighted capacity factor is a reasonable tradeoff between the expected capacity value and the actual capacity factors of Solar PV units.[53] Staff recognizes that any IRP is a planning document. However, where the Company can incorporate Virginia and utility specific data rather than generalized engineering projections, it would be prudent to do so.

Finally, regarding the Company's REC price forecast, Staff readily admits that the Company's filing could be determined to have met the Commission's directive to "incorporate historic prices" for the purposes of the 2018 Corrected IRP. However, in future IRPs, the Company should take Staff's critiques under advisement and continue to refine its REC price forecasting to: a statistical projection based on historic prices; abandon the incremental cost forecasting methodology; and incorporate reasonably known risks to REC prices in the foreseeable future.

Q19. DOES THIS CONCLUDE YOUR TESTIMONY ON THE COMPANY'S 2018 CORRECTED IRP?

[53] As Staff witness Abbott discusses, this performance concern is greatly mitigated with third-party power purchase agreements.

A19. Yes.

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STAFF ATTACHMENT EJW-1

VIRGINIA ELECTRIC AND POWER COMPANY

CORRECTED INTEGRATED RESOURCE PLAN FILING 2018

CASE NO. PUR-2018-00065

RESPONSE TO QUESTION NO. 177

STAFF'S NINETEENTH SET OF INTERROGATORIES AND

REQUESTS FOR THE PRODUCTION OF DOCUMENTS

Staff Set 19-177: Update to Attachment Staff Set 2-18(d) (JMB)

		Average Annual Capacity Factors[1]						
	COD Year	2013	2014	2015	2016	2017	2018	Average
Company Owned Solar Facilities:								
Morgan's Corner	2015				19.2%	19.6%	16.2%	18.3%
Whitehouse	2016					20.4%	16.2%	18.3%
Scott	2016					20.4%	13.7%	17.1%
Woodland	2016					16.7%	19.1%	17.9%
Remington	2017						20.3%	20.3%
Oceana	2017						17.8%	17.8%
Hollyfield	2018							N/A
Puller	2018							N/A
Pecan	2018							N/A
Montross	2018							N/A
Solar Partnership Program	Varies2					13.5%	0.7%	7.1%

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STAFF ATTACHMENT EJW-2

VIRGINIA ELECTRIC AND POWER COMPANY

CORRECTED INTEGRATED RESOURCE PLAN FILING 2018

CASE NO. PUR-2018-00065

RESPONSE TO QUESTION NO. 172 (b)

STAFF'S NINETEENTH SET OF INTERROGATORIES AND

REQUESTS FOR THE PRODUCTION OF DOCUMENTS

Virginia Electric and Power Company
Case No. PUR-2018-00065
Virginia State Corporation Commission Staff
Nineteenth Set

The following response to Question No. 172 (b) of the Nineteenth Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on March 13, 2019 has been prepared under my supervision.

Maria F. Scheller
Vice President and Director
ICF

Question No. 172 (b)

Please reference Figure 10 on page 17 of the corrected IRP and provide the following:

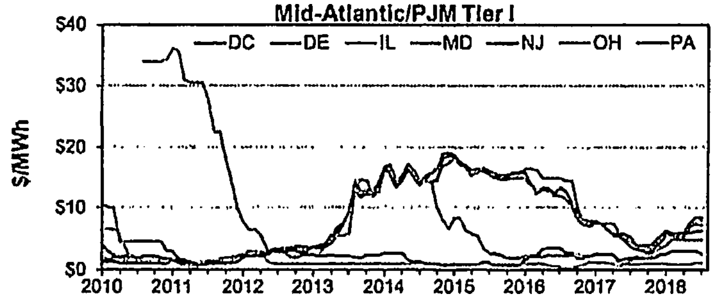
b) Did the source data include historic sales into the Pennsylvania solar REC market? If so, please recalculate Figure 10 removing those sales.

Response:

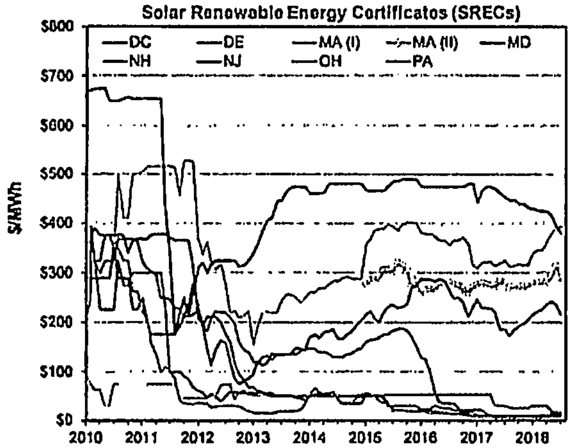
b) The methodology relied on considered historical Tier 1 REC pricing only. It did not rely on historical sales into the Pennsylvania solar REC market.

Regarding solar REC pricing, for the 2018 Compliance Filing, ICF was asked to review and revise the REC price forecast which was generated for the 2018 Plan. ICF's analysis for the 2018 Plan was originally prepared in late 2017, and the update to that forecast [prepared for the 2018 Compliance Filing] is based on information consistent with the vintage of that forecast. In other words, the revised forecast [prepared for the 2018 Compliance Filing] is an update to the original forecast [prepared for the 2018 Plan], rather than a fully revised forecast.

At the time of the 2017 forecasts, Solar and Tier 1 markets had been trending together for several years, as shown in the images below available from the U.S. Renewable Portfolio Standards 2018 Annual Status Report, Galen Barbose, Lawrence Berkeley National Laboratory November 2018. These images show downward trending prices for both Tier 1 and solar RECs in PJM states at low prices:



Source: Marex Spectron. Plotted values are the average monthly closing price for the current or nearest future compliance year traded in each month.



Sources: Marex Spectron, SRECTrade, Flett Exchange. Depending on the source used, plotted values are either the mid-point of monthly average bid and offer prices or the average monthly closing price, and generally refer to prices for the current or nearest future compliance year traded in each month.

More recently, due to changes in the Pennsylvania RPS carve out related to solar resource qualification, prices are trending upward for solar RECs. The changes in SREC policy are not considered within this forecast. Further, the qualification process is still currently active and a final determination of such has not been made such that the stability of SREC pricing and trending remains questionable at this time.

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STAFF ATTACHMENT EJW-3

VIRGINIA ELECTRIC AND POWER COMPANY

CORRECTED INTEGRATED RESOURCE PLAN FILING 2018

CASE NO. PUR-2018-00065

APPLICATION FOR MEMBERSHIP IN THE REGIONAL TRANSMISSION ORGANIZATION KNOWN AS PJM INTERCONNECTION, LLC, CASE NO. PUE-2003-00284

190420187

Paul D. Koonce
Chief Executive Officer - Transmission

Dominion Energy, Inc.
120 Tredegar Street, Richmond, VA 23219
Phone: 804-819-2390, Fax: 804-819-2221

Dominion

June 27, 2003

DOCUMENT CONTROL
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Mr. Joel Peck, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street
Tyler Building, First Floor
Richmond, VA 23219

Dear Mr. Peck:

PUE-2003-00284

Dominion Virginia Power is pleased to submit to the Commission the enclosed application for membership in the regional transmission organization known as PJM Interconnection, LLC ("PJM"). The integration of Dominion Virginia Power's transmission system into PJM will facilitate the development of competitive wholesale and retail electricity markets, as envisioned by the General Assembly when it enacted the Restructuring Act.

Among the important benefits that will result from Dominion Virginia Power's participation in PJM, are the following:

- PJM membership gives Dominion Virginia Power's customers improved access to an expanded inventory of generation totalling nearly 170,000 megawatts. This includes generation to the north and west of Virginia that is cheaper than presently available, and under PJM an increased amount of this would be imported to provide customer savings. In addition access to excess regional generating capacity means that the need to build new generation in Virginia will be reduced in the future.

- Native load is protected. Dominion Virginia Power has taken extraordinary steps to insure that its customers will never have to do without electricity in order for PJM to serve customers elsewhere in the region. There will be no blackouts in Virginia so that people in Philadelphia can have their lights on.

- As required by HB2453, Dominion has conducted a cost-benefit study of its integration into PJM. The results of this study confirm the advantages of membership in regional transmission organizations envisioned by the General Assembly when it passed the Restructuring Act. These advantages include:

-Improved reliability through increased access to a larger and more diverse fleet of generators.
-Substantial savings for customers through access to lower cost power.
-Dominion Virginia Power, which is a net importer of electricity today, will increase its imports under PJM, delivering savings to customers.
-PJM participation will facilitate both wholesale and retail competition.

Our application shows that Dominion Virginia Power's membership in PJM is the best way to ensure that Virginia has a reliable, stable and affordable source of electricity into the future. This is critical for continued economic development in the Commonwealth.

This application also demonstrates that Commission approval of PJM integration is consistent with the intent of the General Assembly as expressed in the Restructuring Act and the Commission's responsibility to ensure reliable and competitively-priced electric service to the citizens of Virginia. Examination of the costs and benefits of PJM integration, its positive impact on reliability and the arrangements that we have made to protect native load customers will show that Dominion's participation in PJM is in the best interest of Virginia's consumers.

Integration of Dominion Virginia Power's transmission facilities into PJM is consistent with the public interest and will promote economic development in Virginia. We therefore hope that this application will proceed to approval on a schedule in accord with HB2453 so that Virginia consumers may realize these important benefits at the earliest possible time.

Sincerely,

Paul D. Koonce

cc: Mr. Ronald A. Gibson
Mr. William F. Stephens
Mr. Richard J. Williams
Mr. Howard M. Spinner
Mr. Cody D. Walker
Arlen Bolstad, Esquire
Ms. Rebecca W. Hartz

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validated. In addition, Virginia will retain its important role in siting transmission enhancements.

In many respects, PJM's approach to transmission planning is no different than what happens with natural gas pipelines today. Taking a regional look at natural gas infrastructure has resulted in the approval of the Cove Point LNG Terminal and the Greenbrier Pipeline as well as the filed Mid-Atlantic expansion – all facilities that originate outside Virginia, but directly benefit consumers in Virginia and encourage continued economic expansion for the Commonwealth.

Ronnie Bailey addresses transmission planning benefits in more detail in his testimony. In addition, the Cost Benefit Study examines this benefit.

Q. **Will PJM provide savings to the Company's retail customers?**

Yes. The Cost Benefit Study examined the quantitative net benefits to the Company's customers of Dominion Virginia Power joining PJM. The Cost Benefit Study indicates that joining PJM will result in significant quantitative net benefits to Dominion Virginia Power's customers through reduced net energy and capacity costs. This result stems principally from greater access to lower cost energy sources and from a reduced need for Dominion Virginia Power to build new high cost, natural gas fired capacity when the Company can obtain greater access to resources in the larger PJM footprint. These savings are derived after factoring in PJM's administrative charges. The study also details several qualitative benefits of joining PJM including enhanced reliability in the Company's service territory through efficient congestion management, greater access to load-serving entities (LSEs) in PJM. The PJM Office of Interconnection is responsible for calculating the amount of generating capacity required to meet the RAA-defined reliability criteria. Following a period of stakeholder review and comment through the Planning Committee, the RAA-Reliability Committee approves the final reserve margin. This final reserve margin is then the basis for allocating a capacity obligation to each LSE within PJM, including utilities, co-ops, munis and Competitive Service Providers (CSPs), based on that LSE's share of the PJM summer peak load.

Q. Please describe PJM's uniform capacity rules.

A. PJM's capacity rules include the following key features:

- Assessment of resource adequacy in PJM begins with determination of the level of installed reserves necessary to meet a loss of load probability criterion of one deficiency in ten years. This is a standard commonly used throughout the utility industry and is also the current standard of the Mid-Atlantic Area Council (MAAC) region within PJM. The process determines the amount of generating capacity required to provide electrical energy to satisfy customer load, especially during peak demand periods, and ensure an acceptable level of service reliability.

- Supply resources used to meet this requirement must pass PJM's deliverability test. This test assesses the ability of the transmission

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Abbott

PART B

Summary of the Testimony of Gregory L. Abbott

My testimony addresses Virginia Electric and Power Company's ("Company") Corrected 2018 Integrated Resource Plan ("Corrected 2018 IRP"). My testimony makes the following findings and recommendations:

- Using the PJM-derived load and energy sales forecast instead of the Company's internal load and energy sales forecasts results in the least-cost plan for the Corrected 2018 IRP being nearly **$8 billion** less costly than the Company's least-cost plan in the 2018 IRP as originally filed;
- If the cold reserve units and Possum Point Unit 5 ("PP5") are not retired, the Company does not need to build any resources of any kind until 2029. Under this scenario, over the 15-year planning period, the model only selects 916 megawatts ("MW") of natural-gas fired combustion turbine units;
- The realized net present value ("NPV") cost savings over the 25-year study period of retiring the cold reserve units and PP5 is just $150 million on a build plan with an NPV cost exceeding $25 billion or a cost reduction of about 0.6%;
- Staff does not believe the cost savings are so compelling that it necessarily justifies retiring approximately 2,100 MWs of capacity over such a short timeframe;
- The incremental NPV cost of the 2018 Grid Transformation and Security Act compared to the least-cost plan is **$5.81 billion**;
- The solar purchase power agreement ("solar PPA") option is substantially less costly than the Company-build solar option;
- Under the solar PPA option, all performance risk is borne by the non-utility solar generator rather than the Company's customers;
- Under the Company-build solar option, the performance risk is borne by the Company's customers, absent a performance guarantee;
- Residential and small commercial customers are particularly better off under the solar PPA option given that costs are allocated on an energy basis and all rate classes pay the same price per megawatt-hour;
- Staff notes that the Company often will perform an analysis on the positive economic impact associated with a generating unit that it proposes to build to justify its approval as part of the broader public interest. Staff believes such an analysis should also be performed before the Company makes a final decision to retire a generating unit;
- Despite the Company's positive cost-benefit analysis of its unit retirements, the immediate impact to customers will be higher monthly bills; and
- The costs of the replacement capacity will predominately be recovered through Rate Adjustment Clauses that will immediately show up on the customer bill upon approval by the Commission. The benefits of the generating unit retirements come in the form of avoided variable O&M costs from operating the retiring units which are booked to base rates. In the near term, the benefits go to the shareholders until such time that they eventually trickle down to customers most likely in the form of higher customer credit offsets than might otherwise be expected.

PUBLIC VERSION

PREFILED TESTIMONY
OF
GREGORY L. ABBOTT

VIRGINIA ELECTRIC AND POWER COMPANY'S INTEGRATED RESOURCE PLAN FILING

CASE NO. PUR-2018-00065

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE VIRGINIA STATE CORPORATION COMMISSION ("COMMISSION").

A1. My name is Gregory L. Abbott. I am a Deputy Director in the Commission's Division of Public Utility Regulation.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A2. My testimony addresses Virginia Electric and Power Company's ("DEV" or "Company") Corrected 2018 Integrated Resource Plan ("Corrected 2018 IRP") filed in compliance with the Commission's December 7, 2018 Order ("Re-File Order") in this proceeding. Specifically, my testimony:

- Evaluates whether the Corrected 2018 IRP complies with the Commission's directive to develop a least-cost plan that does not force the modeling to select any resource, nor exclude any reasonable resource;
- Evaluates whether the Corrected 2018 IRP complies with the Commission's directive to calculate the incremental cost impacts of the mandates contained in the 2018 Grid Transformation and Security Act ("GTSA"),[1] including a comparison to the identified least-cost plan;
- Describes the impact on the build plans and the net present value ("NPV") costs of the various plans of using, as directed by the Commission, the

[1] Also referred to as Senate Bill 966.

Dominion Zone PJM coincident peak load forecast and energy sales forecast, scaled down to the Dominion load serving entity level;

- Discusses the results of using, as directed by the Commission, a 23% capacity factor for solar resources, updates actual historic performance of the Company's existing solar resources through February 2019, and discusses the implications for the modeling of solar resources in future IRP filings;
- Discusses the Company's generating unit retirement analysis;
- Addresses the implications for the IRP planning process of the Company's March 25, 2019 presentation to the New York Stock Exchange regarding the Company's recently announced plans to move forward with $17 billion of capital spending in Virginia over the 2019 through 2023 period; and
- Makes recommendations for information and analyses that the Commission consider as requirements for inclusion in future IRP filings.

Q3. DO YOU HAVE ANY GENERAL COMMENTS?

A3. Yes. Staff has reviewed the Corrected 2018 IRP and believes that the Company has made a good faith effort to comply with all the requirements contained in the Commission's Re-File Order. However, given that both the generating unit retirement analysis and the analysis of demand-side management ("DSM") programs are performed outside of the PLEXOS model and the results of these analyses are then an input into the PLEXOS model, Staff requested additional PLEXOS model runs through discovery to confirm that the Company's identified least-cost plan in the Corrected 2018 IRP is the least-cost plan consistent with the directives in the Commission's Re-File Order. This will be discussed in greater detail later in my testimony.

The Company provides updated model results for the various Regional Greenhouse Gas Initiative ("RGGI") Plans B, C, and D using the model inputs directed by the Commission in its Re-File Order. However, the Company did not update the model assumption for the carbon cap to reflect the final proposed rule emissions cap for Virginia of 28 million tons beginning in 2020 which decreases 3% per year through 2030, as proposed in Virginia State Air Pollution Control Board regulations currently under review. Instead, the Company assumed a much higher emissions cap for Virginia consistent with the model assumption it used in the 2018 IRP as originally filed. Therefore, the costs for RGGI compliance for the various RGGI Plans B through D will be higher than the costs presented in the Corrected 2018 IRP. Staff views the results of the RGGI Plans presented in the Corrected 2018 IRP to be of limited value and will, therefore, not be discussed further in my testimony.

LEAST-COST PLAN

Q4. WHAT DID THE COMMISSION'S RE-FILE ORDER REQUIRE FOR THE LEAST-COST PLAN?

A4. The Commission's Re-File Order states the following regarding the least-cost plan (emphasis added):

> In its corrected 2018 IRP, for purposes of its least-cost plan, *the Company shall not force the modeling to select any resource, nor exclude any reasonable resource*. This requirement does not reflect any finding that the Company should pursue any specific resource included in the least-cost plan; rather, as the Commission has repeatedly recognized, the IRP is a planning document, and *it is reasonable, for planning purposes, to identify the least-cost plan to provide a benchmark against which to measure the costs of other alternative plans.*[2]

[2] Re-File Order at 5 (internal footnotes omitted).

Q5. DID THE COMPANY IDENTIFY A LEAST-COST PLAN AS DIRECTED BY THE COMMISSION IN THE RE-FILE ORDER?

A5. Yes, the Company identifies Plan A: No CO_2 Tax as its least-cost plan. The modeling for the Corrected 2018 IRP least-cost plan differs from the 2018 IRP least-cost plan as originally filed as follows:

- The Company used the Dominion Zone PJM coincident peak load forecast and energy sales forecast, scaled down to the Dominion load serving entity level, as directed by the Commission;
- The Company used a 23% capacity factor for solar as directed by the Commission;
- The solar purchase power agreement ("solar PPA") option was an available resource option for the model to select;
- The natural gas-fired 3X1 combined cycle unit was an available resource option for the model to select;
- The Coastal Virginia Offshore Wind ("CVOW") demonstration project was not forced into the model; and
- The Company included proposed DSM spending of approximately $298 million currently pending before the Commission in Case No. PUR-2018-00168 as a fixed input into the PLEXOS model.[3]

Q6. DOES STAFF AGREE THAT THE COMPANY'S PLAN A IS THE LEAST-COST PLAN CONSISTENT WITH THE DIRECTIVES IN THE COMMISSION'S RE-FILE ORDER?

A6. Yes.

[3] This $298 million of proposed DSM programs is inclusive of lost revenues. In addition, the Company counts this as a component of the $870 million of DSM spending goal under the GTSA.

Q7. HOW DOES THE LEAST-COST PLAN IN THE CORRECTED 2018 IRP COMPARE TO THE LEAST-COST PLAN IN THE 2018 IRP AS ORIGINALLY FILED?

A7. A comparison of the NPV cost of the two least cost plans is shown below.

	NPV Cost ($B)
Least Cost Plan (as originally filed)	33.34
Least Cost Plan (Corrected 2018 IRP)	25.42
Difference	(7.92)

The least-cost plan for the Corrected 2018 IRP is nearly **$8 billion** less costly than the Company's least-cost plan as originally filed.

Q8. WHY IS THE NPV COST OF THE LEAST-COST PLAN IN THE CORRECTED 2018 IRP SO MUCH LOWER THAN THE LEAST-COST PLAN IN THE 2018 IRP AS ORIGINALLY FILED?

A8. This is predominately due to using the Dominion Zone PJM coincident peak load forecast and energy sales forecast, scaled down to the Dominion load serving entity level, as directed by the Commission. This forecast is significantly lower than the Company's internal load and energy sales forecast that was used in the 2018 IRP as originally filed. This lower load and energy sales forecast results in a substantial reduction in the scope of the build plan for the least-cost plan. A comparison of the build plans for the two least-cost plans for the 15-year planning period (2019-2033) is shown below.

	Renewable (MWs)	Fossil (MWs)
Least-Cost Plan (as filed)	4,731	4,122
Least-Cost Plan (Corrected 2018 IRP)	480	3,206
Difference	(4,251)	(916)

The 480 megawatts ("MW or MWs") of solar resources for the Corrected 2018 least-cost plan represent 160 MWs[4] of solar PPAs annually from 2020 through 2022. These solar PPAs were selected by the model on a cost-optimization basis. However, once the investor tax credit expires in 2022, the solar PPAs are no longer competitive with the market. Staff notes that if the investor tax credit is extended in the future, as it has been in the past, then the solar PPA option will likely remain competitive with the market and would be selected by the model beyond 2022. Staff further notes that the model does not select any Company-build solar resources. This demonstrates that the solar PPA option is currently a lower cost option that is more competitive with the market than the Company-build solar resources.[5]

Q9. DID STAFF CONFIRM THAT INCLUDING THE RESULTS OF THE COMPANY'S GENERATING UNIT RETIREMENT ANALYSIS AS AN

[4] The Company included a model constraint that limited the availability of solar PPAs to 160 MWs annually.

[5] This is consistent with the record in Case No. PUR-2018-00101 for approval of the US-3 solar projects which showed that solar PPAs were a lower cost option. The levelized cost of electricity ("LCOE") for a 20-year solar PPA was approximately $41 per MWh compared to approximately $61 per MWh for the US-3 Company-build solar projects.

INPUT INTO THE PLEXOS MODEL IS PART OF THE LEAST COST PLAN?

A9. Yes. As previously mentioned, the Company performed its economic analysis regarding unit retirements outside of the PLEXOS model runs that supported its 2018 IRP, as originally filed. The identified unit retirements and the timing of the unit retirements were then fixed inputs into the PLEXOS model. In order to confirm that the Company's scheduled retirements of the cold reserve units and Possum Point Unit 5 ("PP5") are part of the least-cost plan, Staff requested that the Company perform a PLEXOS model run where the cold reserve units and PP5 are not retired and are instead available for dispatch in the model.[6] The Company's response to Staff Interrogatory No. 21-183[7] shows the results of this model run compared to the least-cost plan in the Corrected 2018 IRP. The Company's response for the 15-year planning period is reproduced below:

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[6] The Company recently announced that the cold reserve units would be retiring by the end of the March 2019 and that PP5 would be retiring in 2021. The following units were placed in cold reserve status during 2018: Bellemeade 1, Bremo 3 & 4, Mecklenberg 1 & 2, Pittsylvania 1, Chesterfield 3 & 4, and Possum Point 3 & 4, representing 1,292 MW of generating capacity. Including the 786 MW of capacity for PP5, a total of 2,078 MW of generating capacity is retired in the least-cost plan.

[7] Attachment GLA-1

	Least-Cost Plan A Corrected 2018 IRP		Least-Cost Plan A Staff Set No. 21-183	
	No CO_2 Base		No CO_2 No Cold Storage/PP5 Retirements	
	Renewable	Fossil	Renewable	Fossil
2019	0	0	0	0
2020	160	0	0	0
2021	160	0	0	0
2022	160	458	0	0
2023	0	458	0	0
2024	0	458	0	0
2025	0	458	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	458	0	0
2029	0	0	0	458
2030	0	0	0	0
2031	0	458	0	458
2032	0	0	0	0
2033	0	458	0	0
Total	**480**	**3,206**	**0**	**916**
NPV ($B)	**$25.42**		**$25.57**	

As can be seen in the table above, the NPV cost of the least cost Plan A in the corrected 2018 IRP is $150 million lower than the NPV cost of the least-cost plan where the cold storage units and PP5 are available for dispatch. This model result validates that the retirements are consistent with the least-cost plan.

Q10. WHAT OTHER OBSERVATIONS WOULD YOU LIKE TO MAKE ON THE TABLE ABOVE?

A10. The build plan under the least-cost plan scenario where these units are not retired looks substantially different than the least-cost plan in the Corrected 2018 IRP. In fact, if these units are not retired, the Company does not need to build any resources of any kind until 2029. Over the 15-year planning period, the model only selects 916 MW of natural-gas fired combustion turbine ("CT") units. The table below summarizes the impacts on the build plan for the least-cost plan for: (1) the PJM-derived load and energy forecast, and (2) the retirements of the cold reserve units and PP5.

	Renewable (MWs)	Fossil (MWs)
Least-Cost Plan (as filed)	**4,731**	**4,122**
Least-Cost Plan (Corrected 2018 IRP)	**480**	**3,206**
Least-Cost Plan (No Unit Retirements)	**0**	**916**

First, using the PJM-derived load and energy forecast significantly lowers the renewable MWs from 4,731 MWs to 480 MWs. Secondly, if the cold reserve units and PP5 are not retired, then the model does not select any renewable MWs.

Likewise, the PJM-derived load and energy forecast lowers the fossil fuel MWs from 4,122 MWs to 3,206 MWs. Additionally, if the cold reserve units and PP5 are not retired, then the fossil fuel MWs are substantially reduced further to just 916 MWs.

Q11. DO YOU HAVE ANY ADDITIONAL COMMENTS ON INCLUDING THESE UNIT RETIREMENTS IN THE LEAST-COST PLAN?

A11. Yes. Based on the above, Staff agrees that the unit retirements are mathematically part of the least-cost plan. However, the realized NPV cost savings of just $150 million on a build plan with an NPV cost exceeding $25 billion only represents a cost reduction of about 0.6%. If only one assumption is slightly changed, this analysis may instead show that the unit retirements are no longer part of the least-cost plan.[8] Thus, even though the unit retirements slightly lowers the NPV costs of the least-cost plan, Staff does not believe these savings are so compelling that it necessarily justifies retiring approximately 2,100 MWs of capacity over such a short timeframe. As will be discussed later in my testimony, given the recent volatility of current energy markets and shifting policy goals, a more conservative strategy of gradualism may be more appropriate where these unit retirements are staggered over a longer time period.

Q12. DID STAFF CONFIRM THAT INCLUDING THE RESULTS OF THE COMPANY'S EXTERNAL DSM ANALYSIS AS AN INPUT INTO THE PLEXOS MODEL IS PART OF THE LEAST COST PLAN?

A12. Yes. As mentioned above, the Company performed its economic analysis regarding DSM outside of the PLEXOS model runs. In addition to the Company's existing DSM programs, the Company included proposed DSM spending of approximately $298 million currently pending before the Commission in Case No. PUR-2018-00168 as a fixed input into the PLEXOS model. The Company performs its DSM analysis using the Strategist model. The DSM programs selected by the Strategist model are then included as a fixed input in the PLEXOS model.

[8] For example, if actual future PJM capacity and energy prices are higher than the Company's forecasts in this IRP, then the retirements may no longer be part of the least-cost plan. Staff has observed a significant amount of variability in the various forecasts used by the Company from one IRP to the next.

In order to confirm that the Company's proposed DSM programs are part of the least-cost plan, Staff requested that the Company perform a PLEXOS model run where the $298 million of proposed programs are removed from the model. The Company's response to Staff Interrogatory No. 21-182[9] shows the results of this model run compared to the least-cost plan in the Corrected 2018 IRP. Removing the proposed DSM programs does not have any impact on the build plan as the model selects an identical set of resources as it did for the Corrected 2018 IRP.

The NPV cost of the least cost Plan A in the Corrected 2018 IRP is $140 million lower than the NPV cost of the least-cost plan where the $298 million of proposed DSM programs are removed from the model. This model result validates that the proposed DSM programs are consistent with the least-cost plan.

Q13. DO YOU HAVE ANY ADDITIONAL COMMENTS ON INCLUDING THE PROPOSE DSM PROGRAMS IN THE LEAST-COST PLAN?

A13. Yes. It should be noted that these DSM programs have not yet been approved by the Commission. Further, the output of the Strategist model for these DSM programs is based on the Company's planning level assumptions regarding estimated energy savings and participation rates for the various proposed DSM programs. Historically, after approval and implementation, actual Evaluation, Measurement and Verification data often reveal that these planning level assumptions are overstated. However, notwithstanding this, for purposes of the

[9] Attachment GLA-2

Corrected 2108 IRP which, by definition, is a planning exercise, Staff is not opposed to using the Company's planning level DSM assumptions.

INCREMENTAL COST OF THE GTSA

Q14. WHAT DID THE COMMISSION'S RE-FILE ORDER REQUIRE FOR THE GTSA?

A14. The Commission's Re-File Order states the following regarding the GTSA:

> As previously ordered, the Company shall also calculate the incremental cost impacts of the mandates contained in Senate Bill 966, including a comparison to the identified least-cost plan. This includes CVOW; 5,000 MW of nameplate wind and solar, including at least 25 percent of such resources from non-utility generators; $870 million in spending on energy efficiency programs; the 30 MW battery storage pilot; the SUP; the Grid Transformation Plan; and the Transmission Line Undergrounding Pilot.[10]

Q15. DID THE COMPANY CALCULATE THE INCREMENTAL COSTS OF THE GTSA AS DIRECTED BY THE COMMISSION IN THE RE-FILE ORDER?

A15. Yes. To the extent that the mandates of the GTSA were not selected by the PLEXOS model in the Corrected 2018 least-cost Plan A, the Company performed a PLEXOS model run in which they forced the model to select the mandates of the GTSA. The Company presents these model results as Plan F in the Corrected 2018 IRP, hereinafter referred to as the GTSA Plan. Table 1 of the Corrected 2018 IRP presents a summary of the NPV costs for all plans and calculates the incremental

[10] Re-File Order at 5 (internal footnotes omitted).

NPV cost of the GTSA Plan to be $5.81 billion higher than the NPV cost of Plan A.

Q16. DO YOU HAVE ANY COMMENTS REGARDING THE $870 MILLION IN DSM SPENDING FOR THE GTSA PLAN?

A16. Yes. Staff notes that $298 million of proposed DSM programs are already included in Plan A, the least cost plan. As mentioned, the Company counts spending on these proposed programs towards the $870 million mandate contained in the GTSA. As such, the GTSA Plan only reflects an additional $572 million of DSM spending. Furthermore, the $298 million of spending on the proposed DSM programs is inclusive of lost revenues. Since the remaining $572 million of generic DSM contained in the GTSA Plan was developed based on prior DSM programs, lost revenues are also implicitly included as a component of the $572 million. To the extent that lost revenues are a program cost that count towards the $870 million mandate contained in the GTSA, this will result in less actual DSM measures being deployed and less energy load reduction than would occur otherwise.

Staff does not take a position at this time on whether lost revenues should be a component of the $870 million mandate contained in the GTSA.[11] Furthermore, Staff does not take a position on whether the $298 million of proposed DSM programs, which have not been developed pursuant to the stakeholder process required by the GTSA, should count toward the $870 million mandate contained in

[11] DEV has recently made public comments that the Company is now committed to propose an aggregate total of $870 million in regulated energy efficiency spending through 2028 exclusive of any counting of projected or actual lost revenues. This has no bearing on the modeling performed for the Corrected 2018 IRP which includes lost revenues as a component of the $870 million.

the GTSA. Staff does note, however, that both assumptions by the Company result in less incremental DSM spending on actual DSM measures in the GTSA Plan and accordingly less energy load reduction.

Q17. DO YOU HAVE ANY COMMENTS REGARDING SOLAR RESOURCES CONTAINED IN THE GTSA PLAN?

A17. As directed by the Commission, and consistent with the GTSA, the GTSA Plan modeled solar assuming 25% of the required solar would be PPAs and 75% would be Company-build. Since the solar PPA option is much lower in cost compared to the Company-build option, this lowers the overall cost of solar resources in the Corrected 2018 IRP compared to the 2018 IRP as originally filed, which modeled 100% of solar resources as Company-build. Staff would further note, that including a higher percentage of solar PPAs toward the 5,000 MW of wind/solar mandate would lower the incremental cost of the GTSA Plan. It is unclear if the requirement in the GTSA that 25% of solar be PPAs is a floor or an exact percentage that cannot be exceeded. However, in planning space, Staff recommends that the Company perform sensitivity model runs in future IRPs that assume 50%, 75%, and 100%, respectively, of solar resources as solar PPAs.

Q18. DO YOU HAVE ANY COMMENTS ON THE COMPANY INCLUDING THE BENEFITS OF THE GRID TRANSFORMATION ("GT") PLAN IN THE INCREMENTAL NPV COST ANALYSIS?

A18. The benefits shown in Table 1 of the Corrected 2018 IRP for the GT Plan were first presented to the Commission in Case No. PUR-2018-00100, the Company's first application for approval of a proposed GT Plan. The Commission's Final Order in that case did not approve most of the elements contained in the proposed GT Plan.[12] Further, the Final Order did not address the adequacy of the Company's benefit estimates. In that case, Staff found that the Company's estimates of quantifiable benefits related to the GT Plan appeared to be unsupported to some degree and/or overstated.

Based on the above, the Company's estimate of the benefits of the GT Plan shown in Table 1 of the Corrected 2018 IRP should be viewed as a Company number for informational purposes only. This benefit estimate was not supported by Staff and was not explicitly addressed by the Commission in its Final Order in Case No. PUR-2018-00100 that rejected most of the proposed GT Plan.

Staff further notes that the costs of the GT Plan, and all other cost items contained in Table 1 of the Corrected 2018 IRP will be collected from ratepayers in the form of higher bills, primarily through rate adjustment clauses ("RACs"). However, to the extent that these GT Plan benefits exist, the benefits will not impact the calculation of customer bills or ameliorate the cost impact of the GT Plan on customer bills.

[12] The Commission did approve the Cyber and Physical Security category and some of the Telecommunications elements of the proposed GT Plan. *See Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2018-00100, Doc. Con. Cen. No. 190130074, Final Order (Jan. 17, 2019).

SOLAR RESOURCE PERFORMANCE AND CAPACITY FACTORS

Q19. DID THE COMPANY USE A 23% CAPACITY FACTOR FOR SOLAR RESOURCES AS DIRECTED BY THE COMMISSION IN ITS RE-FILE ORDER?

A19. Yes.

Q20. DOES THE COMPANY AGREE THAT A CAPACITY FACTOR OF 23% IS APPROPRIATE FOR SOLAR RESOURCES?

A20. No. In the March 7, 2019 letter submitting the Corrected 2018 IRP, the Company respectfully disagrees with the requirement that the Company's modeling include a 23% capacity factor for future solar development. The Company states that the 25.4% capacity factor used in the 2018 IRP as originally filed is a supported and supportable assumption for solar resources.

Q21. DOES STAFF AGREE WITH THE COMPANY'S CONTENTION THAT 25.4% IS THE CORRECT CAPACITY FACTOR TO USE FOR SOLAR RESOURCES?

A21. No, not based on the actual historic performance of solar resources in Virginia and North Carolina in general, and not based on the historic performance of DEV's Company-build solar resources in particular.

Q22. WHAT IS THE HISTORIC TRACK RECORD FOR SOLAR RESOURCES IN THE COMPANY'S VIRGINIA AND NORTH CAROLINA SERVICE TERRITORIES?

A22. This issue has already been discussed extensively in Staff's prior pre-filed testimony regarding the 2018 IRP as originally filed and at the September 24, 2018 public hearing. To obtain updated information following the filing of the Corrected 2018 IRP, Staff Interrogatory No. 19-177 requested that the Company update its response to Staff Interrogatory No. 2-18(d) to reflect solar capacity factors for solar facilities in the Company's Virginia and North Carolina service territories through the end of calendar year 2018.

In my prior pre-filed testimony in this case, I reported that the actual observed utility-specific data over the five-year period 2013-2017 for the Company's owned and operated solar resources in Virginia showed an actual capacity factor of 19.4%. Further, third-party contract solar facilities dispatched by the Company, which are predominately located in North Carolina, experienced an actual capacity factor of 20.3% over the five-year period 2013-2017.

The Company's response to Staff Interrogatory No. 19-177 (Attachment GLA-2) shows that the average capacity factor for the Company's owned and operated solar resources in Virginia decreased from 19.4% over the five-year period 2013-2017 to 18.3% over the six-year period 2013-2018. Further, for third-party contract solar facilities dispatched by the Company, which are predominately located in North Carolina, the average capacity factor has decreased from 20.3% over the five-year period 2013-2017 to 19.8% over the six-year period 2013-2018.

The historic record updated to include calendar year 2018 shows that average solar capacity factors have gotten worse. Based on observed actual data, Staff does not believe it is appropriate to base a long-term investment strategy for solar resources on the Company's suggested 25.4% capacity factor. Actual performance matters and underperformance has real, as opposed to hypothetical, negative consequences for ratepayers.

Q23. PLEASE EXPAND ON THAT POINT.

A23. This can best be demonstrated by the performance of the Company's three existing US-2 solar tracking facilities – Whitehouse, Scott, and Woodland. The Company represented to the Commission that these facilities would have an average capacity factor of 25% when seeking approval of a Certificate of Public Convenience and Necessity ("CPCN") for these facilities. As shown in Attachment GLA-2, none of these facilities have come close to a 25% capacity factor. In 2018, the Scott facility only achieved a capacity factor of 13.7%.

This poor performance for the US-2 solar tracking facilities is primarily due to a host of operational issues that have plagued these facilities since they became operational. The Company's confidential response to Staff Interrogatory No. 19-178 (Attachment GLA-3) updated the outage history for each of DEV's Company-build solar facilities in Virginia through February 2019. Of particular concern, the Whitehouse US-2 solar facility was off-line from **[begin confidential]** [redacted] **[end confidential]** days straight. This is particularly troublesome because the PJM coincident peak occurs in the summer and the Whitehouse US-2 solar facility was off-line for much of the summer.[13]

[13] Staff notes that the US-2 RAC jurisdictional and class cost allocation utilizes the Company's average and excess demand allocator. The outage history of the US-2 solar facilities raises questions as to the appropriateness of treating these facilities the same as traditional generating resources for cost allocation purposes.

Even more troubling is the recent non-performance of the Scott US-2 facility which has only been operational for **[begin confidential]** [redacted] **[end confidential]** over the September 1, 2018 through February 28, 2019 period. The Scott US-2 solar facility has been off-line for **[begin confidential]** [redacted] **[end confidential]** days consecutively through February 28, 2019.

Q24. HOW DOES THE POOR PERFORMANCES OF THE US-2 SOLAR FACILITIES RESULT IN NEGATIVE CONSEQUENCES FOR RATEPAYERS?

A24. The US-2 RAC is currently pending before the Commission in Case No. PUR-2018-00167. The negative impact on ratepayers was displayed in the pre-filed supplemental testimony of Staff witness Samuel in that case. The following table from Staff witness Samuel's supplemental testimony demonstrating the negative consequences to ratepayers is reproduced below.

	Company Factor 1 Total Actual Revenue Requirement for 2017	Price paid per MWH Generated	Value of PJM Energy Purchases Avoided	Net Cost
Residential	$ 6,288,005	$ 150.95	$ 34.07	$ 116.87
GS-1	$ 613,260	$ 119.42	$ 34.07	$ 85.35
GS-2	$ 1,779,288	$ 106.97	$ 34.07	$ 72.90
GS-3	$ 1,681,192	$ 89.65	$ 34.07	$ 55.57
GS-4	$ 926,757	$ 73.96	$ 34.07	$ 39.88
Special Contract	$ 69,495	$ 121.27	$ 34.07	$ 87.20
Churches	$ 54,516	$ 160.63	$ 34.07	$ 126.56
Outdoor Lighting	$ 19,486	$ 137.67	$ 34.07	$ 103.60
Total	$ 11,432,000	$ 119.38	$ 34.07	$ 85.30

In 2017, the actual capacity factors were 20.4%, 20.4%, and 16.7%, respectively, for the Whitehouse, Scott, and Woodland US-2 solar facilities. Since the ratepayers must pay the full revenue requirement regardless of how much energy is produced, the poor performances of the US-2 solar facilities result in ratepayers paying an average of $119.38 per MWh. This is more than triple the average PJM energy price of $34.07 per MWh if the energy had instead been procured from the PJM energy market during the hours of the US-2 facilities' energy production. This cost premium is even more stark for some rate classes because the Company allocates costs using the average and excess demand allocator. Residential customers pay $150.95 per MWh, which is more than quadruple the average PJM energy price of $34.07.

Staff notes that in 2018, the actual performance of the US-2 solar facilities has continued to deteriorate. The actual capacity factors were 16.2%, 13.7%, and 19.1%, respectively, for the Whitehouse, Scott, and Woodland US-2 solar facilities. Thus, the cost per MWh for next year's US-2 RAC filing will be even more prohibitively expensive.

SOLAR PPA VERSUS COMPANY-BUILD SOLAR

Q25. HOW DOES THE COST OF THE SOLAR PPA OPTION COMPARE TO THE COST OF THE COMPANY-BUILD SOLAR OPTION?

A25. This is demonstrated by examining the record in Case No. PUR-2018-00101 for approval of CPCNs for the two US-3 solar projects which showed that solar PPAs were a lower cost option. The LCOE for a 20-year solar PPA was approximately $41 per MWh compared to approximately $61 per MWh for the US-3 Company-build solar projects. It should be noted that the Company represented that these two US-3 solar tracking facilities will achieve an average capacity factor of approximately 28% and the calculated cost per MWh for the US-3 facilities assumes that capacity factor will be achieved.

Q26. DOES A SOLAR PPA SUBJECT THE RATEPAYERS TO THE SAME PERFORMANCE RISK AS A COMPANY-BUILD SOLAR FACILITY?

A26. No. Under a solar PPA, DEV and its ratepayers only pay for the actual energy produced. All performance risk is borne by the non-utility solar generator. In fact, these solar PPA contracts usually have provisions where the non-utility generator must pay a non-performance penalty to the utility for extended outages like the ones discussed earlier that occurred at the Company's Whitehouse and Scott US-2 solar facilities in 2018.

In sharp contrast, under the Company-build option, DEV is entitled to collect its full revenue requirement regardless of actual performance. Thus, all performance risk is borne by the Company's ratepayers.[14]

Q27. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS COMPARING THE SOLAR PPA OPTION TO THE COMPANY-BUILD SOLAR OPTION?

A27. Yes. Under the solar PPA option, the costs paid for the energy received is flowed to ratepayers through the fuel factor. As such, all rate classes pay the same price per MWh received from the solar facility. Under the Company-build solar option,

[14] In Case No. PUR-2018-00101, the Commission approved CPCNs for the two US-3 solar tracking facilities conditioned on a performance guarantee where the Company guarantees a 25% capacity factor for 20 years. To the extent actual performance falls below 25% in a given year, then the Company will provide the energy and solar REC revenue for such shortfall at zero cost to ratepayers. In this way, some but not all of the performance risk is borne by the Company's shareholders.

the revenue requirement is allocated to the various customer classes using the Company's average and excess demand allocator which results in the residential class paying a substantially higher price per MWh compared to the large commercial and industrial classes.

Q28. WHAT ARE YOUR CONCLUSIONS REGARDING THE SOLAR PPA OPTION VERSUS THE COMPANY-BUILD SOLAR OPTION?

A28. Staff reaches the following conclusions:

- The solar PPA option is substantially less costly than the Company-build solar option;
- The solar PPA option is competitive with the PJM energy market and the Company-build solar option is not competitive;
- Under the solar PPA option, all performance risk is borne by the non-utility solar generator;
- Under the Company-build solar option, the performance risk is borne by DEV's ratepayers, absent a performance guarantee;
- Residential and small commercial customers are particularly better off under the solar PPA option given that costs are allocated on an energy basis and all rate classes pay the same price per MWh; and
- The solar PPA option is superior to the Company-build option.

<u>GENERATING UNIT RETIREMENT ANALYSIS</u>

Q29. DO YOU HAVE ANY GENERAL COMMENTS ON THE GENERATING UNIT RETIREMENT ANALYSIS PERFORMED BY THE COMPANY FOR THIS IRP AND PRIOR RETIREMENT DECISIONS?

A29. Yes. The Company is not required to seek approval from the Commission to retire its generating units. However, the Company does need approval from the

Commission for CPCNs for new generating units or transmission projects that may be required to replace the capacity that was retired so that the Company can satisfy its capacity obligation required by PJM or to correct for transmission reliability issues that may arise from the retirement. Thus, the prudency of the retirement decision for a given generating unit may be an issue during the CPCN proceeding for this replacement capacity or for any required transmission improvements. Staff notes, however, that once a generating unit is retired, as a practical matter, it cannot be brought back. So, even if, during the CPCN proceeding for the replacement capacity, it was determined that the retirement decision was imprudent, the retired unit cannot be placed back into service. Staff believes that the only forum where unit retirement decisions can be analyzed before the Company makes a final decision on retirement is an IRP proceeding.

Additionally, the Company performs its retirement analysis for a given generating unit as if the generating unit was a merchant plant operating in PJM. This may not be the most appropriate approach given that DEV is a vertically integrated utility that owns generating units that are backstopped by its captive ratepayers.

Q30. WHY DOES THE COMPANY'S MARKET STRUCTURE MATTER?

A30. Most generating units operating in PJM are merchant plants. When the projected revenues received from the PJM energy and capacity markets can no longer cover the variable O&M costs of the unit, the owner of the merchant plant will notify PJM that the unit is retiring. To the extent that there is undepreciated book value left on the books, the merchant plant's owners/shareholders bear that cost. The merchant plant owner is not obligated to mitigate any transmission system costs that may be caused due to the generating unit shutdown. The merchant plant owner is not responsible for paying for any replacement capacity. The merchant plant owner does not have any obligation to consider the broader public interest of the unit retirement decision.

As a vertically integrated utility that owns distribution, transmission, and generation assets, DEV: (1) is guaranteed recovery of any undepreciated book value associated with a unit retirement; (2) is responsible for mitigating transmission system costs that may be required due to a unit retirement; (3) is responsible for procuring replacement capacity to meet its load obligation to PJM; and (4) should, in Staff's opinion, consider the overall public interest including negative impacts to the local county and broader Virginia economies associated with a unit retirement.

Q31. WHAT IS THE REMAINING NET BOOK VALUE ASSOCIATED WITH THE 2,100 MW OF UNIT RETIREMENTS?

A31. Staff witness Myers discusses this in her pre-filed testimony. Her testimony identifies the remaining net book value of these units in the amount of $330.2 million as of December 31, 2018. All of this will be recovered from ratepayers.

Q32. HOW MUCH REPLACEMENT CAPACITY IS PROJECTED TO BE REQUIRED TO MEET THE COMPANY'S CAPACITY OBLIGATION TO PJM OVER THE 15-YEAR PLANNING PERIOD?

A32. As discussed earlier in my testimony, the retirement of 2,100 MW associated with these units will require an additional 2,290 MW of natural gas-fired CT units and

480 MW of solar PPAs over the 15-year planning period. Essentially, the ratepayers pay for this capacity twice, first to recover the remaining net book value of these units in base rates, and secondly to recover the costs of the replacement capacity which will be predominately through RACs.

Q33. HAVE ANY OF THESE UNIT RETIREMENTS CAUSED TRANSMISSION ISSUES THAT MUST BE ADDRESSED?

A33. Yes. In Case No. PUR-2018-00159, the Company is seeking approval of a CPCN to construct $27.2 million[15] of transmission facilities to resolve potential violations of North American Electric Reliability Corporation ("NERC") reliability standards related to the Company's decision to deactivate and place into cold storage the Company's Bremo Power Station Units 3 and 4. Given the Company's recent announcement to retire these units, these units cannot be brought back on line. This transmission cost was not included in the Company's cost-benefit analysis for these units. This avoided transmission cost should have been included as a benefit of keeping these units in service prior to making a final decision on retirement.[16]

Q34. DID THE COMPANY PERFORM ANY ANALYSIS ON THE IMPACT TO THE LOCAL ECONOMY AND THE VIRGINIA ECONOMY BEFORE MAKING ITS DECISION TO RETIRE THESE UNITS?

[15] Consisting of $5.4 million for transmission work and $21.8 million for substation-related work. In addition, the Company had to deploy a temporary fix in the form of a Temporary Transformer for $2,049,679. In total, the Company's decision to deactivate and retire Bremo Units 3 and 4 results in over $29 million of transmission costs that would not have been necessary absent these retirements.

[16] Staff is aware that the Company is subject to Code of Conduct requirements that prevents the generation planning side of the Company from communicating with the transmission planning side of the Company. However, prior to placing these units into cold storage, the transmission problems were known publicly and should have been included in the cost-benefit analysis prior to making a final decision on retirement of these units.

A34. No, not to Staff's knowledge. The closure of these plants will result in a significant loss of jobs, payroll, spending, and county property taxes in the local counties where the units are located which will ripple throughout the broader Virginia economy due to the multiplier effect. Staff notes that the Company often will perform an analysis on the positive economic impact associated with a generating unit that it proposes to build to justify its approval as part of the broader public interest. Staff believes such an analysis should also be performed before the Company makes a final decision to retire a generating unit.

Q35. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE COMPANY'S RETIREMENT ANALYSIS?

A35. Yes. As I discussed earlier in my testimony, the Company's PLEXOS model run performed in response to Staff discovery showed that the decision to retire the 2,100 MW of generating units lowered the NPV cost over the 25-year study period by $150 million, or 0.6% cost savings, on a build plan with a NPV cost exceeding $25 billion. This amount of cost savings does not make a compelling case to retire these units. The negative impacts to the local counties' and broader Virginia economies may not be warranted for just a 0.6% potential cost savings that may be achieved from the unit retirements. Further, despite the Company's positive cost-benefit analysis, the immediate impact to customers will be higher monthly bills.

Q36. WHY WILL CUSTOMER BILLS INCREASE IN THE NEAR TERM DUE TO THE RETIREMENT OF THESE GENERATING UNITS?

A36. The costs of the replacement capacity will predominately be recovered through RACs that will immediately show up on the customer bill upon approval by the Commission. The benefits of the generating unit retirements come in the form of avoided variable O&M costs from operating the retiring units which are booked to base rates. Since all these retiring generating units are in base rates, the customer will not see any immediate reduction in their bills due to these cost savings. Rather, in the near term, these benefits go to the shareholders until which time that they eventually trickle down to customers most likely in the form of higher customer credit offsets than might otherwise be expected.

Q37. DO YOU HAVE ANY FINAL COMMENTS ON THE COMPANY'S DECISION TO RETIRE 2,100 MW OF GENERATING CAPACITY?

A37. Notwithstanding the concerns outlined above, given the recent volatility of current energy markets and shifting policy goals, a more conservative strategy of gradualism may be more appropriate where these unit retirements are staggered over a longer time-period. A review of past IRPs reveals that current markets have been extremely volatile and dynamic with significant swings in commodity prices, PJM capacity prices, PJM energy prices, the capital cost of solar resources, etc.

It is often said that an IRP is a snapshot in time. While this is true, it is instructive to look back at the prior IRP snapshots to inform decision-making based on the current snapshot. Staff believes such a review indicates that a more cautious gradual approach is more prudent as the technology that is least cost today may not be in the next IRP and the plans that the Company presents from one IRP to the next also vary greatly reflecting this market reality.

Long term planning in these volatile markets is exacerbated by significant shifts in public policy goals from government policymakers that have occurred in recent years.

Q38. HOW HAVE SHIFTS IN PUBLIC POLICY GOALS COMPLICATED LONG-TERM UTILITY PLANNING?

A38. This can best be demonstrated by comparing and contrasting the policy goals contained in the 2007 Regulation Act and the possibility of Virginia linking to RGGI.

The 2007 Regulation Act declared that a new coal-fired generation unit located in southwest Virginia to be in the public interest. Additionally, the 2007 Regulation Act provided for an enhanced rate of return for fossil fuel generating plants to provide an incentive for utilities to construct fossil fuel generating units in Virginia. Not surprisingly, given the enhanced rate of return, DEV constructed several large fossil fuel generating units. The table below shows the fossil fuel generating units that were constructed by the Company pursuant to the 2007 Regulation Act and the enhanced return each plant received.

Rider	Generating Station(s)	B.P. Incentive	Term	Initial Case
S	VCHEC (Coal)	100	12	PUE-2007-00066
R	Bear Garden (Gas)	100	10	PUE-2009-00017
B	Biomasss Conversions - Altavista, Southampton, Hopewell	200	5	PUE-2011-00073
W	Warren (Gas)	100	10	PUE-2011-00042
BW	Brunswick (Gas)	100	10	PUE-2012-00128
GV	Greensville (Gas)	n/a	n/a	PUE-2015-00075

In response to the policy goals contained in the 2007 Regulation Act, the Company developed a significant portfolio of coal and natural gas generation units. The Company's ratepayers are still paying an enhanced rate of return on several of these fossil fuel units.

In 2019, public policy goals shifted dramatically. In accordance with former Governor McAuliffe's Executive Directive 11, the Virginia Department of Environmental Quality ("DEQ") developed its final proposed rule emissions cap for Virginia of 28 million tons beginning in 2020 which decreases 3% per year through 2030, as proposed in Virginia State Air Pollution Control Board regulations currently under review. DEQ's proposed RGGI rule envisions Virginia linking to RGGI. RGGI is a government-imposed cap and trade mechanism designed to impose a carbon tax on the use of fossil fuel generation. Essentially, RGGI levies a carbon tax on fossil fuel generation, payable by electric generators in each RGGI state, with the goal of making fossil fuel generation less competitive, thus leading to reductions in fossil fuel generation and corresponding reductions in CO_2 emissions.

These conflicting government policy goals will result in customers paying the Company an enhanced rate of return, or profit, for fossil fuel generating units which will now be subject to a tax designed to keep these generating units from running. In other words, DEV's customers will be paying the Company an extra profit on fossil fuel plants while simultaneously paying a carbon tax when these units are dispatched.

DEV 2019 INVESTOR DAY PRESENTATION

Q39. HAS THE COMPANY MADE ANY RECENT PUBLIC ANNOUNCEMENTS ABOUT ITS INVESTMENT PLANS THAT ARE NOT PRESENTED IN OR SUPPORTED BY THE 2018 IRP AS ORIGINALLY FILED OR IN THE CORRECTED 2018 IRP?

A39. Yes. On March 25, 2019, DEV made a presentation to the New York Stock Exchange that announced plans to move forward with $17 billion of capital investment in Virginia for the 2019 through 2023 period ("2019 Capital Investment Announcement").

Q40. HOW DOES THIS 2019 CAPITAL INVESTMENT ANNOUNCEMENT DIFFER FROM THE BUILD PLANS PRESENTED IN THE 2018 IRP?

A40. The Company's $17 billion capital investment strategy presented in the 2019 Capital Investment Announcement is significantly different from the Plans presented in the Company's 2018 IRP as originally filed and the Corrected 2018 IRP. Staff Interrogatory No. 21-186 requested that the Company identify how much of this $17 billion is included in each of the Corrected 2018 IRP Plans A through F, and how much of this spending is not reflected in each of the corrected 2018 IRP Plans A through F. The Company's response provided a table with the requested information reproduced below.

Attachment Staff Set 21-186 (AV)

	Investor Day (2019 - 2023)	Plan A 2018 Compliance Filing (2019 - 2023)	Plan A 2018 Compliance Filing (2019 - 2043)	Plans B to F 2018 Compliance Filing (2019-2023)	Plans B to F 2018 Compliance Filing (2019-2043)
Transmission	$ 4.30	$ -	$ -	$ 0.172 [1]	$ 0.172 [1]
Solar	$ 3.70	$ -	$ -	$ 2.20	$ 6.80
Customer Growth[4]	$ 1.70	$ -	$ -	$ -	$ -
Grid Transformation	$ 1.60	$ -	$ -	$ 1.321 [2]	$ 2.219
Nuclear Relicensing	$ 1.20	$ 2.10	$ 3.40	$ 2.10	$ 3.40
Offshore Wind	$ 1.10	$ -	$ -	$ 0.30	$ 0.30
Pumped Storage	$ 1.00	$ -	$ -	$ -	$ -
Strategic Undergrounding	$ 0.80	$ -	$ -	$ .899 [3]	$ 1.398
Environmental	$ 0.50	$ 0.50	$ 0.50	$ 0.50	$ 0.50
Renewable-enabling CTs	$ 0.50	$ 0.77	$ 4.90	$ 0.77	$ 4.80
	$ 16.40				

Notes: Unless otherwise noted, the values are in nominal dollars.

1) Plans B to F include UG Pilot #1 as shown in the 2018 Compliance Filing. The value is in 2018 dollars.

2) This value is in 2018 dollars. Converting it to nominal dollars yields a total cost of $1.6 billion, matching the investor day presentation value.

3) This value is in 2018 dollars. Converting it to nominal dollars yields a total cost of $0.8 billion, matching the investor day presentation value. Included costs for the Strategic Undergrounding Program are from 2016 - 2023.

4) Customer growth includes distribution infrastructure and growth of future customer spend. This was not analyzed in the Compliance Filing.

When compared to the Corrected 2018 IRP Plans B through F, among other things, the Company's $17 billion capital investment strategy over 2019-2023 contains significantly higher investments in Company-build solar ($3.70 billion compared to $2.20 billion), Offshore Wind ($1.1 billion compared to $0.30 billion), and Pumped Storage ($1.00 billion compared $0).

Q41. PLEASE DISCUSS THE INCREASE IN INVESTMENT FOR COMPANY-BUILD SOLAR OVER THE 2019 THROUGH 2023 PERIOD.

A41. Despite the fact that the Corrected 2018 IRP clearly shows that solar PPAs are both a lower cost option and that the non-utility solar generator bears all of the performance risk, the Company's 2019 Capital Investment Announcement envisions a short-term action plan where a significantly higher investment in Company-build solar is planned.

This is troubling to Staff given the Company's dismal historic track record operating DEV's existing Company-build solar facilities. Rather than slowing down until the Company can demonstrate that it can efficiently operate its Company-build solar facilities, DEV apparently is planning to accelerate spending on solar regardless of actual performance.

Q42. PLEASE DISCUSS THE INCREASE IN INVESTMENT FOR OFFSHORE WIND OVER THE 2019 THROUGH 2023 PERIOD.

A42. The $1.1 billion planned investment in Offshore Wind identified in the Company's 2019 Capital Investment Announcement is significantly higher than the $300 million CVOW Offshore Wind Demonstration Project. The Commission's Final Order in Case No. PUR-2018-00101 approved the prudency determination for CVOW. Importantly, the Company represented in that case that CVOW was needed to gather information before the Company could make any determination regarding a larger scale investment in offshore wind.

It now appears, based on the Company's 2019 Capital Investment Announcement, that the Company has determined that it does not need to get the results from the CVOW demonstration before planning for an investment in a broader deployment of offshore wind. This begs the question of why CVOW is needed if the Company is not going to wait to get the results of the demonstration project.

Q43. PLEASE DISCUSS THE COMPANY'S PLANS FOR A BILLION DOLLAR INVESTMENT IN PUMPED STORAGE.

A43. Not only has a pumped storage facility not been included in any of the plans presented in the 2018 IRP or any prior IRP, the Company has also not presented any cost data in the 2018 IRP or any prior IRP concerning a pumped storage facility. Given the Company's Capital Investment Announcement of a $1 billion planned investment in pumped storage, it appears that the Company has developed plans and cost estimates for this resource but has chosen to not include this information in its IRP filings before the Commission.

Q44. DO YOU HAVE ANY FINAL COMMENTS ON THE COMPANY'S CAPITAL INVESTMENT ANNOUNCEMENT?

A44. Yes. Staff notes that there are drastically different visions for the next five years contained in the Company's 2019 Capital Investment Announcement compared to the 2018 IRP. In Staff's view, this raises questions of whether the IRP is driving the Company's investment strategy, or the Company's investment strategy is driving the Company's planning process. It appears that the latter may be the case. This raises further questions of whether the Company is backing into the results contained in its IRPs to support announcements to Wall Street like the Company's 2019 Capital Investment Announcement.

RECOMMENDATIONS FOR FUTURE IRP FILINGS

Q45. WHAT ARE YOR RECOMMENDATIONS?

A45. Staff makes the following recommendations for future IRP filings:

- Staff recommends that the Company base future build plans presented in future IRP filings on the PJM-derived peak load and energy sales forecast scaled down to the Dominion load serving entity level as described by Staff witness White. If it chooses, the Company can also use its internal peak load and energy sales forecast as a sensitivity run.

- Staff recommends that the Company use a 23% capacity factor for solar resources in future IRP filings,[17] consistent with the Commission's directive in its Re-File Order. In addition, Staff recommends that the Company provide build plans using a 20% solar capacity factor as a sensitivity run or actual if the actual historic average capacity factor is higher 20%. If it so chooses, the Company can also use its projected solar capacity factor as a sensitivity run.
- Staff recommends, in future IRP filings, that the Company model solar resources using 25%, 50%, 75%, and 100% as solar PPAs, respectively.

Q46. DOES THIS CONCLUDE YOUR TESTIMONY?

A46. Yes, it does.

[17] The Re-File Order directed a solar capacity factor of 23%. In selecting the 23 percent capacity factor, the Commission stated in the Re-File Order that it weighed evidence regarding the causes of the actual solar capacity factors and evidence supporting technological efficiency improvements of solar resources over time. Thus, 23% represents a balancing of actual historic performance and expected improvements in solar technology going forward. Based on the record herein, the Commission may determine that a different capacity factor is appropriate for the next IRP filing.

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ATTACHMENT GLA-1

2018 IRP Refile - 23.0% Solar Capacity Factor, PJM Load Forecast

Plan A — Staff Set 21-183

	No CO2 Base		No CO2 - No Cold Stroage/PP5 Retirements	
	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs
2018	-	-	-	-
2019	-	-	-	-
2020	160	-	-	-
2021	160	-	-	-
2022	160	458	-	-
2023	-	458	-	-
2024	-	458	-	-
2025	-	458	-	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	458	-	-
2029	-	-	-	458
2030	-	-	-	-
2031	-	458	-	458
2032	-	-	-	-
2033	-	458	-	-
Total	480	3,206	-	916
2034	-	-	-	458
2035	-	-	-	-
2036	-	458	-	-
2037	-	-	-	458
2038	-	458	-	-
2039	-	-	-	-
2040	-	-	-	458
2041	-	458	-	-
2042	-	-	80	458
2043	-	458	-	-
Total	480	5,038	80	2,748

NPV ($B)	$ 25.42	$ 25.57
		$0.15

Notes:

Cold Storage units removed from cold storage and allowed to operate during study period.

Possum Point 5 retirement removed and allowed to operate during study period

ATTACHMENT GLA-2

Staff Set 19-177: Update to Attachment Staff Set 2-18(d) (IMB)

	COD Year	2013	2014	2015	2016	2017	2018	Average
		Average Annual Capacity Factors[1]						
Company Owned Solar Facilities:								
Morgan's Corner	2015				19.2%	19.6%	16.2%	18.3%
Whitehouse	2016					20.4%	16.2%	18.3%
Scott	2016					20.4%	13.7%	17.1%
Woodland	2016					16.7%	19.1%	17.9%
Remington	2017						20.3%	20.3%
Oceana	2017						17.8%	17.8%
Hollyfield	2018							N/A
Puller	2018							N/A
Pecan	2018							N/A
Montross	2018							N/A
Solar Partnership Program	Varies2					13.5%	0.7%	7.1%
Third-Party Contract Solar Facilities (NUGs):								
Plymouth Solar	2012	17.5%	20.3%	18.5%	20.3%	20.5%	20.6%	19.6%
Bethel Price Solar	2014			24.7%	21.1%	15.4%	16.1%	19.3%
Dogwood Solar	2014			22.0%	23.4%	24.0%	20.2%	22.4%
HXOap Solar	2014			15.4%	17.1%	9.8%	19.1%	15.4%
Jakana Solar	2014			21.5%	21.4%	22.6%	20.5%	21.5%
Lewiston Solar	2014			18.6%	23.0%	21.8%	20.5%	21.0%
Williamston Solar	2014			21.2%	23.3%	22.6%	20.6%	21.9%
Windsor Solar	2014			21.6%	22.4%	22.3%	21.3%	21.9%
510 REPP One Solar	2015				17.7%	13.1%	17.1%	16.0%
Creswell Aligood Solar	2015				24.2%	25.2%	25.0%	24.8%
Downs Farm Solar	2015				17.6%	19.3%	19.6%	18.8%
Everetts Wildcat Solar	2015				24.0%	25.3%	24.5%	24.6%
GKS Solar- SolNC2	2015				20.7%	18.9%	19.3%	19.7%
SolNC5 Solar	2015				20.1%	24.7%	22.8%	22.5%
SolNCPower6 Solar	2015				21.7%	25.1%	24.6%	23.8%
Tarboro Solar	2015				17.4%	20.6%	22.1%	20.0%
Two Mile Desert Road - SolNC1	2015				19.9%	20.6%	20.0%	20.2%
Windsor Cooper Hill Solar	2015				9.6%	18.7%	19.1%	15.8%
Aulander Hwy 42 Solar	2016					14.9%	22.3%	18.6%
Barnhill Road Solar	2016					21.6%	21.0%	21.3%
Battleboro Farm Solar	2016					20.2%	18.2%	19.2%
Battleboro Solar	2016					20.6%	20.2%	20.4%
Bethel Solar (Strata)	2016					22.1%	19.6%	20.9%
Bradley PVI- FAE IX	2016					12.9%	18.2%	15.6%
Conetoe Solar	2016					22.6%	23.3%	23.0%
FAE X -Shawboro	2016					21.9%	21.7%	21.8%
FAE XVII -Watson Seed	2016					19.8%	19.9%	19.8%
FAE XVIII -Meadows	2016					19.0%	20.2%	19.6%
Garysburg Solar	2016					20.8%	20.1%	20.4%
Gaston Solar	2016					21.2%	19.8%	20.5%
Gates Solar	2016					20.9%	22.8%	21.9%
Green Farm Solar	2016					22.3%	16.6%	19.4%
Hardison Farm Solar	2016					23.3%	21.2%	22.2%
Hemlock Solar	2016					18.6%	22.7%	20.6%
Leggett Solar	2016					18.7%	22.7%	20.7%
Long Farm 46 Solar	2016					18.3%	17.8%	18.1%
MCI Solar	2016					22.0%	20.0%	21.0%
Modlin Farm Solar	2016					23.1%	21.3%	22.2%
River Road Solar	2016					18.6%	18.0%	18.3%
Schell Solar Farm	2016					20.7%	19.9%	20.3%
Seaboard Solar	2016					20.7%	19.6%	20.1%
Simons Farm Solar	2016					22.2%	21.7%	21.9%
SolNC10 Solar	2016					18.4%	19.6%	19.0%
Sugar Run Solar (SolNC3)	2016					23.2%	22.2%	22.7%
TWE Kelford Solar	2016					16.9%	18.1%	17.5%
Whitakers Farm Solar	2016					21.8%	20.3%	21.0%
White Farm Solar	2016					23.3%	20.4%	21.9%
Williamston Speight Solar	2016					22.3%	19.6%	20.9%
Williamston West Farm Solar	2016					19.9%	19.8%	19.8%
Winton Solar	2016					14.1%	21.1%	17.6%
Woodland Solar	2016					21.5%	20.1%	20.8%
Essex Solar Center	2017						21.6%	21.6%
Cork Oak Solar	2017						19.2%	19.2%
Davis Lane Solar	2017						20.0%	20.0%
FAE XXI -Benthall Bridge PVI	2017						19.9%	19.9%
FAE XXII -Baker PVI	2017						20.6%	20.6%
FAE XXXV -Turkey Creek	2017						18.9%	18.9%
FIAE II - Flat Meeks	2017						9.8%	9.8%
Floyd Road Solar	2017						20.5%	20.5%
HXNAir Solar One	2017						1.0%	1.0%
Sunflower Solar	2017						19.6%	19.6%
Chowan Jehu Road Solar	2018							N/A
Cottonwood Solar	2018							N/A
FAE XIX - American Legion PVI	2018							N/A
FAE XXV - Vaughn's Creek	2018							N/A
Phelps 158 Solar Farm	2018							N/A
Shiloh Hwy 1108 Solar	2018							N/A
TWE Ahoskie Solar Project	2018							N/A
Sandy Solar	2018							N/A
Northern Cardinal	2018							N/A
Carl Friedrich Gauss Solar	2018							N/A
Sun Farm VI	2018							N/A
Sun Farm V	2018							N/A

[1] Capacity factors only provided for full years of operation. COD year excluded as the partial year is not representative of the requested annual capacity factor.

[2] 2017 was the first year that all Solar Partnership facilities were COD for a full year.

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ATTACHMENT GLA-3

CONFIDENTIAL

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PART C

Myers

Summary of Carol B. Myers' Testimony

My August 24, 2018, pre-filed testimony in this proceeding discussed, among other things, the accounting treatment of twelve generating units identified in the 2018 Integrated Resource Plan ("2018 IRP") of Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("Company") to be retired early in 2021 or 2022. Ten of these units were placed in cold reserve status during calendar year 2018. On March 25, 2019, the Company announced that it will immediately retire the ten generating units in cold reserve status. Additionally, the Company announced plans to retire Unit 5 at Possum Point Power Station in 2021. My testimony identifies the remaining net book value of these units in the amount of $333.20 million as of December 31, 2018, and discusses the potential regulatory accounting treatment of any associated impairment or abandonment write-off of these costs pursuant to § 56-585.1 A 8 of the Code of Virginia.

PRE-FILED TESTIMONY

OF

CAROL B. MYERS

VIRGINIA ELECTRIC AND POWER COMPANY
CASE NO. PUR-2018-00065

April 18, 2019

Q1. PLEASE STATE YOUR NAME AND THE POSITION YOU HOLD WITH THE STATE CORPORATION COMMISSION ("COMMISSION").

A1. My name is Carol B. Myers. I am a Deputy Director in the Commission's Division of Utility Accounting and Finance.

Q2. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING ON AUGUST 24, 2018?

A2. Yes, I did. That testimony discussed, among other things, the accounting treatment of twelve generating units identified in the 2018 Integrated Resource Plan ("2018 IRP") of Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("Dominion" or "Company") to be retired early in 2021 or 2022.[1] Those units are identified in the following table:

[1] *See* Exhibit 3 (Myers) at 3 through 8.

Table 1
2018 IRP Generating Unit Retirement Date Assumptions

Generating Unit	MW Output	2018 IRP Retirement Date	Fuel Type
Bellemeade Power Station	267 MW	2021	Natural Gas
Bremo Power Station - Unit 3	71 MW	2021	Natural Gas
Bremo Power Station - Unit 4	156 MW	2021	Natural Gas
Chesterfield Power Station - Unit 3	98 MW	2021	Coal
Chesterfield Power Station - Unit 4	163 MW	2021	Coal
Mecklenburg Power Station - Unit 1	69 MW	2021	Coal
Mecklenburg Power Station - Unit 2	69 MW	2021	Coal
Pittsylvania Power Station	83 MW	2021	Wood
Possum Point Power Station - Unit 3	96 MW	2021	Natural Gas
Possum Point Power Station - Unit 4	220 MW	2021	Natural Gas
Possum Point Power Station - Unit 5	786 MW	2021	Oil
Yorktown Power Station - Unit 3	790 MW	2022	Oil

Except for Unit 5 at Possum Point Power Station and Unit 3 at Yorktown Power Station, the Company placed the other ten units into cold reserve status during calendar year 2018.

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A3. On March 25, 2019, the Company announced that it will immediately retire the ten units in cold reserve status. Additionally, the Company announced plans to retire Unit 5 at Possum Point Power Station in 2021. The purpose of my testimony is to identify the remaining net book value of these units and to discuss the potential regulatory accounting treatment of any associated impairment or abandonment write-off of these costs.

Q4. PLEASE IDENTIFY THE REMAINING NET BOOK VALUE OF THESE UNITS AS OF DECEMBER 31, 2018.

A4. The remaining net book value of these units as of December 31, 2018, was $333.20 million. Historically, the capital cost of the units has been recovered from customers through the depreciation expense included in base rate cost of service. The remaining net book value of $333.20 million is the undepreciated capital cost of the units that remained to be recovered from customers as of December 31, 2018. The following table presents this remaining net book value, by unit:[2]

Table 2
Net Book Values as of December 31, 2018
(In Millions of Dollars)

Generating Unit	MW Output	Retirement Date	Net Book Value	
Bellemeade Power Station	267 MW	Immediate	$	61.33
Bremo Power Station - Unit 3	71 MW	Immediate	$	22.72
Bremo Power Station - Unit 4	156 MW	Immediate	$	37.01
Chesterfield Power Station - Unit 3	98 MW	Immediate	$	13.08
Chesterfield Power Station - Unit 4	163 MW	Immediate	$	37.25
Mecklenburg Power Station - Unit 1	69 MW	Immediate	$	16.89
Mecklenburg Power Station - Unit 2	69 MW	Immediate	$	16.39
Pittsylvania Power Station	83 MW	Immediate	$	40.03
Possum Point Power Station - Unit 3	96 MW	Immediate	$	2.93
Possum Point Power Station - Unit 4	220 MW	Immediate	$	11.22
Possum Point Power Station - Unit 5	786 MW	2021	$	74.35
Total	**2078 MW**		**$**	**333.20**

[2] For power stations where all units are retired, the unit net book values identified above include an allocation of common plant. *See* my supporting workpaper and the Company's response to Environmental Respondents' Interrogatory Set 12, Question No. 4 included in Appendix A to my testimony for additional details.

Q5. PLEASE DISCUSS THE POTENTIAL REGULATORY ACCOUNTING TREATMENT OF ANY IMPAIRMENT OR ABANDONMENT WRITE-OFF OF THESE COSTS.

A5. It is Staff's understanding that the Company will likely write-off a significant portion of the remaining net book value of these units on its books in calendar year 2019, in order to recognize the abandonment or impairment of the units for financial reporting purposes in the accounting period in which the decision to retire the units occurred.[3] If the Company takes such a write-off on its books, § 56-585.1 A 8 of the Code of Virginia, as amended by the 2018 Grid Transformation and Security Act,[4] requires that, for purposes of reviewing Dominion's earnings in triennial reviews, the cost of asset impairments related to early retirement determinations made by the Company for generation facilities fueled by coal, natural gas, or oil are deemed fully recovered in the test period in which they were recorded per books by the Company for financial reporting purposes. All other things remaining equal, the Virginia jurisdictional portion of such a write-off will serve to reduce the Company's earnings in the first triennial review and will thus reduce potential refunds due to customers or dollars available for customer credit reinvestment offset in that proceeding.[5]

[3] Company witness Kelly addressed abandonment or impairment entries in his rebuttal testimony. *See* Exhibit 44 (Kelly Rebuttal) at 11.

[4] 2018 Va. Acts of Assembly ch. 296.

[5] For illustrative purposes, a one-time write-off of $333.20 million would reduce the Company's Virginia jurisdictional annual earned return on equity by approximately 4 percentage points.

Q6. DOES THIS CONCLUDE YOUR TESTIMONY?

A6. Yes, it does.

MYERS APPENDIX A

Net Book Values of Early Retirement Units
As of December 31, 2018
Supporting Workpaper

Plant/Unit	Acquisition Value	Accumulated Depreciation	Net Book Value (NBV)	Allocation of Common Plant	Net Book Value with Common Plant Allocated
Chesterfield Unit 3	66,906,094	53,822,688	13,083,406	-	13,083,406
Chesterfield Unit 4	91,546,090	54,294,430	37,251,660	-	37,251,660
Mecklenburg Commor	11,064,367	2,549,671	8,514,696	-	
Mecklenburg Unit 1	17,709,945	5,137,534	12,572,411	4,322,058	16,894,469
Mecklenburg Unit 2	17,337,043	5,141,100	12,195,942	4,192,638	16,388,580
Bellemeade Common	8,832,014	1,996,199	6,835,815	-	
Bellemeade Unit 1	54,241,371	14,344,024	39,897,347	5,004,904	44,902,251
Bellemeade Unit 2	18,049,838	3,454,458	14,595,380	1,830,911	16,426,291
Bremo Common	41,097,622	21,677,466	19,420,157	-	
Bremo Unit 3	38,158,461	22,826,160	15,332,301	7,387,210	22,719,511
Bremo Unit 4	58,125,276	33,150,655	24,974,621	12,032,947	37,007,568
Possum Point Unit 3	46,350,765	43,424,579	2,926,186	-	2,926,186
Possum Point Unit 4	66,242,769	55,024,621	11,218,147	-	11,218,147
Pittsylvania Common	19,604,343	2,781,805	16,822,538	-	
Pittsylvania Unit 1	33,507,113	11,439,248	22,067,865	15,993,733	38,061,598
Pittsylvania Unit 2	785,741	97,472	688,269	498,825	1,187,094
Pittsylvania Unit 3	530,634	75,333	455,301	329,980	785,281
Possum Point Unit 5	245,630,619	171,284,862	74,345,757	-	74,345,757
Total	**835,720,104**	**502,522,305**	**333,197,799**	**51,593,206**	**333,197,799**

*Source: Environmental Respondents' Set 12, Question No. 4

Virginia Electric and Power Company
Case No. PUR-2018-00065
Environmental Respondents
Twelfth Set

The following supplemental response to Question No. 4 (dated April 8, 2019) of the Twelfth Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on March 12, 2019 has been prepared under my supervision.

Matthew J. Williams
Supervisor, Fixed Asset Accounting
Dominion Energy Services

Question No. 4

Please provide the book value, amortization, and depreciation schedules for the following:

a) each of the Company's coal-fired generating units;
b) each of the Company's natural gas-fired generating units;
c) each of the Company's nuclear generating units;
d) each of the Company's biomass generating units;
e) each of the Company's heavy fuel oil units;
f) each of the Company's light fuel oil units;
g) each of the Company's conventional hydro units;
h) each of the Company's pumped hydro units.

Response:

See Attachment ER Set 12-4 (1) (MJW) for the acquisition values, accumulated depreciation, and net book values as of December 31, 2018 for the requested Dominion Energy Virginia generating units. Depreciation rates for these units are determined as part of a Depreciation Study for Dominion Energy Virginia, which was last performed as of December 31, 2016. To the extent the request for "depreciation schedules" refers to the rates determined as a result of this study, see Confidential Attachment ER Set 12-4 (2) (MJW) for the relevant excerpted pages (VI-4 – VI-13) from the 2016 Depreciation Study showing the depreciation rates for the related generating units. Confidential Attachment ER Set 12-4 (2) (MJW) contains confidential information in its entirety and is being provided pursuant to pursuant to the protections set forth in 5 VAC 5-20-170 and subject to the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information entered on May 18, 2018, as modified by Hearing Examiner's Rulings dated June 7, 2018 and June 14, 2018, and any subsequent protective order or ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and pursuant to Agreements to Adhere executed pursuant to any such orders or rulings.

Attachment ER Set 12-4(1)(MJW)
Net book value of Virginia Power Generating Units
As of December 31, 2018

Coal

Plant/Unit	Acquisition Value	Accumulated Depreciation	Net Book Value
Chesterfield Common	780,556,229.70	185,347,350.36	595,208,879.34
Chesterfield Unit 3	66,906,094.44	53,822,688.41	13,083,406.03
Chesterfield Unit 4	91,546,089.63	54,294,429.64	37,251,659.99
Chesterfield Unit 5	265,789,049.13	160,724,906.98	105,064,142.15
Chesterfield Unit 6	721,361,877.26	333,187,661.86	388,174,215.40
Clover Common	119,975,521.09	44,859,784.27	75,115,736.82
Clover Unit 1	246,826,586.42	103,328,053.35	143,498,533.07
Clover Unit 2	233,953,154.55	94,871,051.18	139,082,103.37
Mecklenburg Common	11,064,366.95	2,549,670.81	8,514,696.14
Mecklenburg Unit 1	17,709,945.17	5,137,534.28	12,572,410.89
Mecklenburg Unit 2	17,337,042.58	5,141,100.37	12,195,942.21
Mount Storm Common	339,333,588.35	154,938,572.95	184,395,015.40
Mount Storm Unit 1	502,664,261.02	289,888,889.37	212,775,371.65
Mount Storm Unit 2	434,317,169.75	251,757,624.04	182,559,545.71
Mount Storm Unit 3	564,430,300.60	323,744,945.88	240,685,354.72
Virginia City	1,973,100,658.30	298,818,353.53	1,674,282,304.77

Natural Gas

Plant/Unit	Acquisition Value	Accumulated Depreciation	Net Book Value
Bear Garden	635,637,532.48	72,557,913.56	563,079,618.92
Bellemeade Common	8,832,013.69	1,996,198.79	6,835,814.90
Bellemeade Unit 1	54,241,370.55	14,344,023.99	39,897,346.56
Bellemeade Unit 2	18,049,838.12	3,454,457.75	14,595,380.37
Bremo Common	41,097,622.38	21,677,465.56	19,420,156.82
Bremo Unit 3	38,158,460.84	22,826,159.85	15,332,300.99
Bremo Unit 4	58,125,275.76	33,150,655.06	24,974,620.70
Brunswick	1,105,321,568.57	71,664,183.66	1,033,657,384.91
Chesterfield Unit 7	152,138,230.27	84,110,003.51	68,028,226.76
Chesterfield Unit 8	151,675,780.59	94,429,887.79	57,245,892.80
Gordonsville Common	15,698,447.38	4,514,519.43	11,183,927.95
Gordonsville Unit 1	22,390,712.83	7,236,113.48	15,154,599.35
Gordonsville Unit 2	21,674,214.00	7,896,012.52	13,778,201.48
Greensville	1,270,128,766.16	3,961,826.91	1,266,166,939.25
Possum Point Common	60,875,139.37	17,250,145.27	43,624,994.10
Possum Point Unit 3	46,350,765.44	43,424,579.39	2,926,186.05
Possum Point Unit 4	66,242,768.59	55,024,621.22	11,218,147.37
Possum Point Unit 6	438,688,346.72	103,973,498.37	334,714,848.35

Rosemary Common	15,579,320.35	5,449,222.94	10,130,097.41
Rosemary Unit 1	10,532,012.25	4,360,181.22	6,171,831.03
Rosemary Unit 2	7,444,015.24	3,106,616.49	4,337,398.75
Warren County	1,060,106,383.22	117,472,500.78	942,633,882.44

Combustion Turbine

Plant/Unit	Acquisition Value	Accumulated Depreciation	Net Book Value
Chesapeake CT Common	2,995,985.70	1,645,443.58	1,350,542.12
Chesapeake CT Unit 1	2,592,103.44	2,214,851.54	377,251.90
Chesapeake CT Unit 2	2,444,033.00	2,426,893.74	17,139.26
Chesapeake CT Unit 4	2,124,916.52	2,095,403.53	29,512.99
Chesapeake CT Unit 6	2,086,278.68	2,056,783.08	29,495.60
Darbytown Common	15,121,278.71	10,426,932.10	4,694,346.61
Darbytown Unit 1	19,618,896.83	17,106,548.16	2,512,348.67
Darbytown Unit 2	19,332,215.40	16,026,278.20	3,305,937.20
Darbytown Unit 3	19,233,050.17	16,441,201.91	2,791,848.26
Darbytown Unit 4	18,817,283.88	16,643,677.74	2,173,606.14
Elizabeth River CT Common	7,647,671.81	2,310,515.02	5,337,156.79
Elizabeth River CT Unit 1	17,421,879.95	6,835,081.58	10,586,798.37
Elizabeth River CT Unit 2	16,955,026.64	6,787,511.92	10,167,514.72
Elizabeth River CT Unit 3	16,684,088.93	7,563,471.07	9,120,617.86
Gravel Neck CT Common	11,729,846.38	5,452,991.50	6,276,854.88
Gravel Neck CT Unit 1	3,387,351.93	2,683,119.95	704,231.98
Gravel Neck CT Unit 2	4,432,258.35	2,674,249.66	1,758,008.69
Gravel Neck CT Unit 3	21,794,916.75	17,803,002.40	3,991,914.35
Gravel Neck CT Unit 4	20,756,346.99	17,420,343.54	3,336,003.45
Gravel Neck CT Unit 5	20,799,544.20	17,576,202.27	3,223,341.93
Gravel Neck CT Unit 6	22,061,235.40	18,257,440.27	3,803,795.13
Ladysmith CT Common	71,474,271.16	17,916,239.02	53,558,032.14
Ladysmith CT Unit 1	46,358,976.71	12,532,314.24	33,826,662.47
Ladysmith CT Unit 2	47,087,117.74	12,631,214.32	34,455,903.42
Ladysmith CT Unit 3	57,438,452.99	9,109,088.31	48,329,364.68
Ladysmith CT Unit 4	42,876,740.54	9,392,751.68	33,483,988.86
Ladysmith CT Unit 5	66,507,379.78	13,562,245.41	52,945,134.37
Low Moor CT Common	7,210,508.48	7,056,004.03	154,504.45
Low Moor CT Unit 1	1,096,538.48	957,381.27	139,157.21
Low Moor CT Unit 2	670,215.86	653,522.55	16,693.31
Low Moor CT Unit 3	694,196.56	694,196.56	-
Low Moor CT Unit 4	632,548.41	486,397.48	146,150.93
Northern Neck CT Common	8,421,402.86	8,094,360.23	327,042.63
Northern Neck CT Unit 1	775,262.80	582,223.30	193,039.50
Northern Neck CT Unit 2	606,799.94	422,222.41	184,577.53
Northern Neck CT Unit 3	531,086.40	469,148.99	61,937.41
Northern Neck CT Unit 4	614,539.54	414,819.29	199,720.25
Possum Point CT Common	2,010,039.96	1,985,646.61	24,393.35
Possum Point CT Unit 1	1,537,505.09	1,530,449.25	7,055.84
Possum Point CT Unit 2	1,492,462.68	1,472,371.04	20,091.64

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Possum Point CT Unit 3	1,487,069.21	1,480,013.37	7,055.84
Possum Point CT Unit 4	1,829,559.01	1,822,503.17	7,055.84
Possum Point CT Unit 5	1,491,686.17	1,484,630.33	7,055.84
Possum Point CT Unit 6	1,531,848.16	1,524,792.32	7,055.84
Remington CT Common	27,475,350.41	12,499,569.95	14,975,780.46
Remington CT Unit 1	45,241,807.84	12,970,175.00	32,271,632.84
Remington CT Unit 2	45,803,222.17	12,784,803.09	33,018,419.08
Remington CT Unit 3	47,000,245.81	11,245,403.96	35,754,841.85
Remington CT Unit 4	45,358,607.32	13,003,266.53	32,355,340.79

Nuclear

Plant/Unit	Acquisition Value	Accumulated Depreciation	Net Book Value
North Anna Common	741,024,463.48	341,858,360.61	399,166,102.87
North Anna Unit 1	981,317,282.15	577,125,013.71	404,192,268.44
North Anna Unit 2	814,836,848.82	381,491,863.53	433,344,985.29
Surry Common	700,276,088.33	485,295,842.57	214,980,245.76
Surry Unit 1	1,020,825,803.33	519,704,176.79	501,121,626.54
Surry Unit 2	745,615,631.41	378,306,909.96	367,308,721.45

Biomass

Plant/Unit	Acquisition Value	Accumulated Depreciation	Net Book Value
Altavista Common	76,961,783.96	15,982,360.04	60,979,423.92
Altavista Unit 1	2,117,507.72	1,958,228.34	159,279.38
Altavista Unit 2	65,898.25	8,168.33	57,729.92
Hopewell Common	72,920,829.74	15,522,478.00	57,398,351.74
Hopewell Unit 1	1,014,044.98	406,659.23	607,385.75
Hopewell Unit 2	86,269.50	21,128.25	65,141.25
Pittsylvania Common	19,604,342.69	2,781,804.92	16,822,537.77
Pittsylvania Unit 1	33,507,112.72	11,439,247.81	22,067,864.91
Pittsylvania Unit 2	785,741.37	97,472.00	688,269.37
Pittsylvania Unit 3	530,633.76	75,333.02	455,300.74
Southampton Common	69,227,591.79	15,447,991.71	53,779,600.08
Southampton Unit 1	1,537,810.52	1,091,349.06	446,461.46
Southampton Unit 2	250,662.35	147,453.47	103,208.88

Oil

Plant/Unit	Acquisition Value	Accumulated Depreciation	Net Book Value
Possum Point Unit 5	245,630,619.39	171,284,862.01	74,345,757.38
Yorktown 3	234,539,073.72	172,835,235.60	61,703,838.12
Yorktown Common	91,519,224.12	55,194,926.94	36,324,297.18

Conventional Hydro

Plant/Unit	Acquisition Value	Accumulated Depreciation	Net Book Value
Gaston Common	12,958,729.66	5,102,851.32	7,855,878.34
Gaston Unit 1	34,149,420.81	28,624,291.01	5,525,129.80
Gaston Unit 2	5,461,628.00	1,701,492.45	3,760,135.55
Gaston Unit 3	3,708,992.82	1,384,612.79	2,324,380.03
Gaston Unit 4	2,656,657.94	605,686.71	2,050,971.23

Roanoke Rapids Common	17,126,882.56	5,677,045.40	11,449,837.16
Roanoke Rapids Unit 1	34,407,913.39	26,095,406.45	8,312,506.94
Roanoke Rapids Unit 2	2,500,329.20	1,719,574.38	780,754.82
Roanoke Rapids Unit 3	2,000,280.99	1,257,725.84	742,555.15
Roanoke Rapids Unit 4	2,199,736.31	1,432,845.43	766,890.88
North Anna Hydro Common	462,399.00	367,905.19	94,493.81
North Anna Hydro Unit 1	1,325,026.00	931,295.25	393,730.75
North Anna Hydro Unit 2	361,506.00	291,858.01	69,647.99

Pumped Hydro

Plant/Unit	Acquisition Value	Accumulated Depreciation	Net Book Value
Bath Common	769,211,109.58	494,540,580.60	274,670,528.98
Bath Unit 1	47,424,778.04	24,180,607.47	23,244,170.57
Bath Unit 2	46,608,803.00	23,688,797.56	22,920,005.44
Bath Unit 3	45,029,181.85	22,897,826.83	22,131,355.02
Bath Unit 4	54,000,465.31	23,560,363.66	30,440,101.65
Bath Unit 5	42,799,150.09	23,753,784.11	19,045,365.98
Bath Unit 6	50,977,323.26	26,269,103.18	24,708,220.08