COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

PETITION OF

APPALACHIAN POWER COMPANY **Case No. PUR-2022-00001**

For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia

DIRECT TESTIMONY

of

SHELLEY KWOK

on behalf of

THE SIERRA CLUB

July 29, 2022

Revised September 21, 2022

Summary of the Direct Testimony of Shelley Kwok

Appalachian Power Company (APCo or the Company) submitted a petition for approval of an environmental rate adjustment clause for capital investments and operations and maintenance (O&M) expenses to comply with the federal Effluent Limitation Guidelines (ELG) regulations in lieu of retirement of the Amos and Mountaineer coal plants. In support of this petition, APCo provided a spreadsheet analysis to show that these costs, and the continued ownership of the Amos and Mountaineer coal plants, are part of a least-cost resource plan for Virginia ratepayers relative to retirement or removal from the Virginia rate base and replacement of the capacity. My independent modeling examines four scenarios and one sensitivity:

(1) West Virginia Public Service Commission (PSC) Preferred includes the ELG investments at Amos and Mountaineer and assumes both plants operate at an annual 69 percent capacity factor through 2040. I also tested a higher coal price sensitivity to reflect the challenges the Company could face in procuring the quantity of coal required to sustain operations at 69 percent.

(2) APCo Preferred includes the ELG investments at Amos and Mountaineer and assumes APCo operates both plants economically through 2040.

(3) Synapse Full Coal Removal assumes the removal of Amos and Mountaineer from the Virginia rate base on December 31, 2028 and replacement with alternatives.

(4) Synapse Partial Coal Removal assumes removal of the Amos plant from the Virginia rate base on December 31, 2028, and replacement with alternatives.

I find that it is uneconomic, and not in the best interest of Virginia ratepayers, for APCo to invest in ELG compliance at Amos and to continue to operate the plant through 2040. Removing Amos from the Virginia rate base beginning in 2029 will result in a net present value (NPV) of savings of up to $202 million between now and 2040. I therefore recommend that the Commission deny APCo's petition for recovery of ELG costs for both the Amos and Mountaineer plants.

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Shelley Kwok and I am an Associate with Synapse Energy Economics, Inc. (Synapse). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics, Inc.

A. Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q. Please summarize your work experience and educational background.

A. At Synapse, I conduct analysis and write publications that focus on a variety of issues relating to electric utilities, including integrated resource planning and power plant economics. I have supported the development of testimony and analysis in litigated dockets across the country.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the PLEXOS and EnCompass models.

I hold a Bachelor of Science in Mechanical Engineering from Tufts University in Somerville, Massachusetts. A copy of my current resume is attached as Exhibit SK-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Sierra Club.

Q. Have you testified previously before the State Corporation Commission of Virginia?

A. No, but I have provided analysis and testimony support on behalf of Sierra Club in Case Nos. PUR-2020-00258 and PUR-2020-00015, where we assessed the economics of the Amos and Mountaineer plants. I also provided EnCompass modeling support on behalf of Sierra Club in Case No. PUR-2020-00035, where our team conducted alternative modeling for Virginia Electric & Power Company's Integrated Resource Plan (IRP). I also provided analysis support on behalf of Sierra Club in Case No. PUR-2022-00006, in which we assessed the prudence of Virginia Electric & Power Company's effluent limitation guidelines (ELG) project at the Mt. Storm coal plant.

Q. Have you performed similar work before other utility commissions?

A. Yes. I was the lead author of a report that was submitted in New Mexico Public Regulation Commission Case No. 21-00169-UT. For this report, I assessed Southwestern Public Service Company's Tolk Analysis Report and IRP and conducted alternative resource modeling using EnCompass on behalf of Sierra Club. I am currently leading development of comments in docketed proceeding where my team is reviewing the coal plant operational practices of a utility in the South. I have also provided analysis and testimony support in dockets across the country, including in the states of Georgia, Michigan, New York, North Carolina, and South Carolina.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony evaluates Appalachian Power Company's (APCo or the Company) application for approval of a rate adjustment clause for capital investments and operations and maintenance (O&M) expenses at the Amos and Mountaineer coal plants (the Plants) to comply with the federal ELG regulations in lieu of retirement. I review the analysis that APCo provided to support its application and explain the shortcomings in the Company's approach. I also evaluate the cost savings to Virginia ratepayers if Virginia exits its share of the Amos and Mountaineer coal plants in 2028 and instead meets its energy and capacity needs with a clean energy portfolio and market imports. I present the results of an alternative modeling analysis that compares four scenarios and one sensitivity.

1a) **West Virginia Public Service Commission (PSC) Preferred** includes the ELG investments at APCo's four existing coal-fired units at Amos and Mountaineer and assumes APCo operates those units at an annual 69% capacity factor through 2040. This assumption reflects the West Virginia PSC's September 2, 2021, Order (West Virginia Commission Order) that mandated that "[t]he capacity factor for [Amos and Mountaineer] should be

69 percent in this case with the potential for an increased capacity factor as described in this Order."[1]

1b) West Virginia PSC Preferred, high coal price sensitivity includes the ELG investments at Amos and Mountaineer, assumes that APCo operates those units at an annual 69% capacity factor through 2040, and applies a higher price of coal to reflect the challenges the Company could face in procuring the quantity of coal required to sustain operations at 69%.

2) APCo Preferred includes ELG investments at Amos and Mountaineer and assumes that APCo operates all four units economically through 2040.

3) Synapse Full Coal Removal removes all four units at Amos and Mountaineer from the Virginia rate base on December 31, 2028, and meets Virginia's system needs with a combination of solar PV, wind, battery storage, and market purchases.

4) Synapse Partial Coal Removal removes Amos from the Virginia rate base on December 31, 2028, and meets remaining system needs with clean energy resources and imports. This scenario includes ELG investments at Mountaineer and operates that unit at an annual 69% capacity factor through 2040.

1 *Petition of Appalachian Power Company & Wheeling Power Company to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect*, West Virginia Public Service Commission Case No. 21-0339-E-ENEC, Commission Order (September 2, 2021), available at https://bit.ly/3J8lt51.

Q. Please identify the documents and filings on which you base your opinions.

A. My findings rely primarily upon my own EnCompass modeling analysis as well as the testimony, exhibits, and discovery responses of APCo and its witnesses. I also rely on public industry publications and data sources.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit No.	Exhibit	Confidentiality
SK-1	Resume of Shelley Kwok	Public
SK-2	Company Response to Sierra Club Discovery Request No. 3-4	Public
SK-3	Company Response to Sierra Club Discovery Request No. 6-4	Public
SK-4	Company Response to Sierra Club Request No. 2-21 – Attachment 1	Public
SK-5	Company Response to Sierra Club Discovery Request No. 3-5	Public
SK-6	Company Response to Sierra Club Discovery Request No. 2-3	Public
SK-7	Company Response to Sierra Club Discovery Request No. 7-4	Public
SK-8	Company Response to Sierra Club Discovery Request No. 5-9	Public
SK-9	Company Response to Sierra Club Discovery Request. 6-10	Public
SK-10	Company Response to Sierra Club Discovery Request No. 5-10	Public
SK-11	Company Response to Sierra Club Request No. 6-1 – Attachment 1	Public

2. OVERVIEW OF TESTIMONY AND CONCLUSIONS

Q. Please summarize your primary findings.

A. First, I find that the Company's analysis was insufficient to support APCo's application. Specifically, the Company did not utilize an optimized capacity expansion and dispatch model and instead relied on an overly simplified capacity replacement analysis. The Company calculated the cost of immediately replacing 100 percent of Virginia's share of the Plants' capacity by 2029, instead of modeling the optimal replacement of only the firm capacity that Virginia's system would need to meet its reserve margin, while also meeting Virginia's Renewable Portfolio Standard (RPS) goals. The Company also used an unreasonably high estimate for capacity prices in the relevant PJM market zone, given structural market changes and historical patterns for that zone.

Second, my independent modeling demonstrates that it is uneconomic, and not in the best interest of Virginia ratepayers, for APCo to invest in ELG compliance costs at Amos, which would allow it to continue running the plant through 2040. Removing Amos from the Virginia rate base beginning in 2029 will result in a net present value (NPV) of savings of at least $202 million through 2040.

While these results indicate ratepayers *may* be better off removing only Amos from the rate base, other risk factors associated with longer-term dependency on coal generation indicate that removal of both plants from APCo Virginia's rate base is likely prudent. When considering the additional risk of potential carbon cost liabilities and the effect of higher coal prices, the marginal value of Mountaineer shrinks. Also, as I will describe in the body of this testimony, renewable portfolio standard (RPS) requirement shortfalls associated with the West Virginia PSC and APCo Preferred scenarios increase the net value of the coal removal scenarios, resulting in additional cost savings to Virginia ratepayers compared to the results displayed in Table 1.

My modeling analysis found that an optimal capacity replacement portfolio contains a combination of solar, wind, storage, and firm capacity purchases. A summary of the resource portfolio mix, capacity imports, and NPV of revenue requirements for APCo's Virginia jurisdiction in the Synapse modeling is shown in Table 1. Positive values in the net capacity exchange row represents imports, while negative values represent exports.

Table 1. Summary of Synapse Modeling Results in 2040, Virginia Jurisdiction

	WV PSC Preferred	**APCo Preferred**	**Full Coal Removal from Rate Base**	**Partial Coal Removal from Rate Base**
NPVRR* (2022-2040, $ Millions)	$5,915	$5,743	$5,927	$5,713
Solar (MW)	2,929	2,929	3,507	3,507
Wind (MW)	855	855	524	524
Battery Storage (MW)	625	625	476	476
Gas (MW)	512	512	512	512
Coal (MW)	2,295	2,295	167	823
Net capacity exchange (MW)	-1,369	-1,639	310	-285

** Note: NPVRR numbers do not account for the additional costs caused by REC deficits observed in Scenarios 1 and 2.*

Q. Please summarize your primary recommendation.

A. Based on my analytical findings above and as described in further detail in this testimony, I recommend that the Commission deny Virginia's share of the costs associated with ELG compliance at Amos and at Mountaineer.

3. SUMMARY OF APCO'S PETITION

Q. What is APCo requesting in its Petition in this docket?

A. APCo is requesting the Commission's approval of its environmental rate adjustment clause (E-RAC), which amounts to $33.6 million for the Rate Year of December 1, 2022 through November 30, 2023. This amount includes actual and projected capital costs for the environmental projects needed to comply with the federal ELG rule. This rule establishes limits on the discharge of wastewater from flue gas desulfurization, fly ash and bottom ash transport water, and flue gas mercury control wastewater.

The total cost of ELG compliance at the Plants is $148.5 million for Amos and $48.4 million for Mountaineer.[2] Virginia's jurisdictional share of the ELG investments at both Plants is $98 million.[3]

2 Direct Testimony of Brian D. Sherrick at 9:20–10:4.

3 Direct Testimony of James F. Martin at 4:2.

Q. Did APCo present any analysis supporting its Petition?

A. Yes. Company witness James F. Martin prepared an economic analysis that compared the cost of keeping Amos and Mountaineer in the Virginia rate base with the cost of replacing the capacity of the plants with three alternative resource portfolios:

- Case 1 assumes replacement of both Plants with a mix of renewables and gas;
- Case 2 assumes replacement of both Plants with all renewables and storage; and
- Case 3 compares replacement of both Plants with capacity purchases from PJM.

This analysis covered the years 2025 through 2040 and was completed outside of PLEXOS, in a simple Excel spreadsheet.

Q. What were the results of APCo's analysis?

A. APCo found that maintaining ownership of the Plants was less expensive than any of the three replacement options through 2040, assuming the full capacity of Virginia's share of both Plants were replaced with new resources or market capacity purchases.

Q. Do you have any concerns with the Company's modeling?

A. Yes. APCo's spreadsheet analysis overstates the amount of capacity that it would need to acquire to replace both Plants. First, the Company modeled a one-for-one replacement of Virginia's share of both Plants and assumed it would need to replace 1,907 MW of firm capacity by 2029.[4] The Company did not account for the firm capacity contributions from the rest of the generating units in its resource portfolio, both existing and planned, when calculating the amount of capacity that is needed to replace the plants. The Company

4 Direct Testimony of James F. Martin at 12:22.

only needs to replace the amount of firm capacity required to satisfy its reserve margin, which may not be as much as the full capacity of both Plants. Second, the Company used the nameplate capacity of both Plants when calculating the cost of PJM paper capacity in line 4 of Witness Martin's Table 3.[5] APCo would only need to replace the amount of *firm* capacity offered by the Plants, if required to meet reserve requirements. The Company stated that the Plants' unforced capacity (UCAP) rating—*i.e.*, the percentage of nameplate capacity available after accounting for the Plants' forced outage rate—was 3,814 MW and thus 386 MW lower than the value the Company used to calculate necessary replacement capacity for Case 3.[6]

The Company's analysis also did not optimize the timing of the replacement capacity in Case 1 or 2 to account for the falling price of renewables over time, nor did it include a scenario that allowed a combination of renewable resources and firm-capacity purchases to replace the coal capacity. Finally, APCo did not consider the impact that uneconomic coal generation could have on energy costs or revenues in its analysis. Given the West Virginia Commission Order requiring both Plants to operate at a 69-percent capacity factor and its implications on economic dispatch at both Plants, this was a large oversight.

Q. Do you agree with APCo's methodology and findings?

A. No. I believe that the Company should only be building or purchasing the amount of firm capacity it needs to meet its reserve margin, unless the resources are being added

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5 *See* Martin E-RAC Case 1 workpaper 2-7 Final.xlsx. This source includes voluminous spreadsheet data and can be provided upon request.

6 Direct Testimony of James F. Martin at 9:21.

economically to provide energy or meet RPS goals. I also believe that the Company should be strategically timing the replacement capacity to minimize costs. The Company's RPS Plan, which was provided in Schedule 1 of Witness Martin's testimony (reproduced below in Table 2) shows that the Company's projected reserve margin in 2028 exceeds its 14.9 percent requirement and that it will have a capacity surplus in a future where both Plants stay in service. This indicates that APCo would not have to replace the full firm capacity of both Plants immediately in 2029 if the Plants were removed from service.[7]

Table 2. Company's Projected Reserve Margin, Portfolio 1 (w/ New Additions)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
14.3%	13.4%	14.3%	15.9%	19.0%	18.5%	18.5%	18.4%	18.6%	22.7%

2032	2033	2034	2035	2036	2037	2038	2039	2040
23.6%	25.2%	26.1%	26.9%	33.7%	35.1%	37.0%	39.8%	8.7%

Source: RPS Plan at Table 30

Q. Do you present an alternative to APCo's modeling analysis?

A. Yes. In contrast to the Company's over-simplified analysis, I used an industry standard capacity expansion and production cost model to develop an optimal replacement resource portfolio that can provide the capacity and energy that APCo would need to meet system needs over the entire planning horizon, assuming both Plants were removed from the Virginia rate base. Using APCo's own input values, with one key exception for

7 James F. Martin Schedule 1 at Table 30.

capacity market prices, I allowed the model to select between building new resources or purchasing capacity from the market to meet firm capacity and energy needs. My analysis also considered the impact of West Virginia's capacity factor mandate on net energy revenues. I discuss my modeling in depth in the next section of my testimony.

4. SYNAPSE MODELING ANALYSIS

Q. Which model did you use to perform your analysis?

A. My analysis uses the EnCompass capacity optimization and dispatch model, developed by Anchor Power Solutions, to simulate resource choice impacts in APCo's service territory.

Q. Is EnCompass a widely accepted industry model?

A. Yes. EnCompass was released in 2016 and numerous major utilities have transitioned to the model since that time. Those utilities include Xcel Energy (Colorado, Minnesota, and New Mexico), Minnesota Power, Otter Tail Power, Public Service New Mexico, Duke Energy, and Tennessee Valley Authority, among others.

Q. Explain the scenarios that Synapse modeled.

A. Synapse modeled four different scenarios and one fuel price sensitivity.

1a) **West Virginia PSC Preferred** includes ELG investments at APCo's existing coal-fired units and operates those units at an annual 69% capacity factor through 2040 in accordance with the West Virginia Commission Order.

1b) **West Virginia PSC Preferred, high coal price sensitivity**, which includes the ELG investments at APCo's four existing coal-fired units, operates those units at an annual 69 percent capacity factor through 2040, and applies a higher price of coal to reflect the challenges the Company could face to procure the quantity of fuel it needs to run the plants at that level.

2) **APCo Preferred**, which includes the ELG investments at APCo's four existing coal-fired units and operates those units economically through 2040.

3) **Synapse Full Coal Removal**, which removes all four units from the Virginia rate base on December 31, 2028.

4) **Synapse Partial Coal Removal**, which removes Amos from the Virginia rate base on December 31, 2028; includes ELG investments at Mountaineer; and operates that unit at an annual 69% capacity factor through 2040.

Q. Describe how each scenario was set up in EnCompass.

A. I designed Scenario 1 to mirror the Company's modeling presented in RPS Plan, which was provided in Schedule 1 of Martin's testimony, and then modified the coal plant generation assumptions for Amos and Mountaineer to reflect a 69 percent annual capacity factor across the analysis period in accordance with the West Virginia Commission Order. In Portfolio 1 of the RPS Plan, APCo assumed that both Plants would retire in 2040, and the Company would build renewables to comply with the Virginia Clean Energy Act (VCEA). Because APCo will need to meet its RPS requirements even if both Plants remain online, I set up the model to add the same new resource portfolio as Portfolio 1.[8]

8 Because the Company presented its resource additions on a PJM planning year basis and I conducted my modeling on a calendar year basis, I had to make some adjustments to account

Scenario 1b was identical to Scenario 1a, except that I tested a higher coal price sensitivity based on the Company's acknowledgement that it may not be able to secure the quantity of coal needed to operate the Plants at a 69% capacity factor at the current price.[9]

I set up Scenario 2 in the same way as Scenario 1a and modified the coal plant generation assumptions to use the same capacity factors for Amos and Mountaineer through 2040 that the Company found in its Portfolio 1 results. I did this to represent a future most similar to what the Company would project if the ELG costs are approved, and it does not have to abide by the West Virginia Commission Order.

In Scenario 3, I conducted the modeling in two stages. I assumed that coal generation would align with the profile observed in the APCo Preferred case up through 2028. Then, I removed half of the Plants' capacity and generation starting in 2029 to represent Virginia removing the Plants from its rate base. I then allowed EnCompass to build any combination of solar, wind, and storage as well as purchase from the market to meet its reserve margin and load requirements. These builds and imports represent the optimal resource plan for APCo's Virginia ratepayers if both Plants were removed from the rate base. I then re-ran the scenario with the full capacity of both Plants, while locking in the same builds from the first stage. The final results represent a future where West Virginia customers take on 100% ownership of both Plants in 2029 and run them at a 69% capacity factor, while Virginia customers meet their energy and capacity needs with alternatives.

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for this difference. Namely, I presumed that the gas combined cycle unit that the Company added in 2040 / 2041 in Portfolio 1 would come online at the beginning of calendar year 2041 after the coal plants are retired, and thus I did not include it in my modeling.

9 Company Response to Sierra Club Request No. 3-4, attached as Exhibit SK-2.

For Scenario 4, I used the same two-step process as Scenario 3, with the difference being that in stage 1, I removed only Amos's capacity and generation contribution to Virginia starting in 2029. I assumed Mountaineer would keep contributing to Virginia through 2040 while operating at a capacity factor of 69% starting in 2029.

Q. Did you match APCo's input assumptions in your Synapse modeling?

A. Largely, yes, but with a critical difference for capacity market price assumptions, as I will explain later in testimony. To ensure a valid comparison, the Synapse analysis used APCo's assumptions from the RPS Plan modeling exercise for peak and annual energy, load shape, reserve margin, unit retirements, energy market prices, replacement resource costs, and avoidable ongoing costs at both Amos and Mountaineer under the 2028 rate base removal dates. I relied on APCo's gas and coal prices in all scenarios except for the high coal price sensitivity (Scenario 2b).

Due to differences in the way that PLEXOS and EnCompass model hybrid solar plus storage projects, I did not use a single levelized cost of energy (LCOE) for a hybrid resource as APCo did. Instead, I used APCo's solar LCOE for the solar component and APCo's capital cost for the storage component after accounting for the cost savings from paired systems.[10]

The sources for key input assumptions are shown in Table 3 below.

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10 To account for the cost savings of paired systems, I multiplied APCo's standalone solar capital costs by the percentage discount applied by National Renewable Energy Lab's 2022 Annual Technology Baseline (NREL 2022 ATB) to paired storage resources compared to standalone storage resources.

Table 3. Synapse Modeling Input Assumptions

Input	Source*
Load Forecast	SC 2-02, Confidential Attachment 1
Load Shape	SC 2-19, Attachment 1
Reserve Margin	14.9%, per Direct Testimony of Martin at 16:10
Coal Prices	SC 4-01 Attachment 2, SC 3-01 Confidential Attachment 1, SC 5-01 ES Attachment 1
High Coal Price	EIA AEO 2020, low oil and gas supply scenario
Gas Prices	SC 4-01 Attachment 2, SC 5-02 ES Attachment 1
RGGI Prices	SC 2-21 Attachment 1
Market Energy Prices	SC 4-01, Attachment 1. AP Market Purchase Prices EIA_RGGI-VCEA.csv
Onshore Wind Costs	SC 2-47 Confidential Attachment 1
Solar Costs	SC 2-47 Confidential Attachment 2
Battery Costs	Martin Schedule 1, Appendix D
Paired Battery Cost	Martin Schedule 1, Appendix D with NREL ATB adjustments
Amos / Mountaineer Heat Rates	SC 4-06 Confidential Attachment 1
RPS Requirement	SC 2-03, Attachment 11
ELCC Values	SC 2-3 Attachment 3, SC 4-3 Attachment 1
Renewable Capacity Factors	SC 2-20 Attachments 1 and 2
Avoidable Amos / Mountaineer Capital Costs	Martin E-RAC Case 1 workpaper 2-7 Final.xlsx
WACC	6.842% per Company Response to Sierra Club Request No. 2-44
Amos / Mountaineer Capacity Factors	SC 2-27 CONFIDENTIAL Attachment 1

* *Note: Many of these input sources include voluminous spreadsheet data. As such, the input sources are not attached as exhibits to this testimony, but can be provided to the Commission and properly-authorized parties upon request*

Q. Explain the modifications you made to APCo's capacity price input assumptions.

A. I adjusted APCo's capacity price forecast to reflect the fact that recent PJM capacity prices have been much lower than APCo's forecast. The zone in which APCo serves load has historically seen the lowest level of capacity prices of the market, and significant structural changes to the PJM capacity market have also occurred recently.

The PJM market capacity price forecast that the Company used in its analysis to calculate the cost of purchasing replacement capacity in Case 3 was created in July 2021 and had not been updated to reflect any of the changes to the PJM capacity market since that date.[11] The most recent PJM capacity auction for the 2023/2024 delivery year had a clearing price of $34.14/MW-day for the "Rest of RTO" zone in which APCO serves load.[12] However, the Company's forecast listed prices of $100/MW-day to $151/MW-day for this time period, which are 3 to 4 times higher than the actual cleared price.[13]

Q. Has the Company provided an updated forecast that accounts for recent changes in the PJM capacity market?

A. No. The Company stated that it has not updated its capacity price forecast since the July 2021 forecast was created.[14] Since July 2021, PJM has adopted numerous changes that were incorporated in the 2023/2024 Base Residual Auction. This includes the Minimum

11 Company Response to Sierra Club Request No. 6-4, attached as Exhibit SK-3.

12 PJM Interconnection, *PJM Capacity Auction Secures Electricity Supplies at Competitive Prices* (June 2022), available at https://bit.ly/3b2WXWo.

13 Company Response to Sierra Club Request No. 2-21 Attachment 1.xlsx, attached as Exhibit SK-4.

14 Company Response to Sierra Club Request No. 6-4, attached as Exhibit SK-3.

Offer Price Rule (MOPR), the Market Seller Offer Cap (MSOC), and Effective Load Carrying Capability (ELCC) updates.[15] All of these changes have contributed to more competitive capacity bids in recent auctions. For these reasons, I believe that the Company's forecast is out of date and not representative of current market conditions. Because of this, I developed my own estimate as to what a potential capacity price forecast could look like given these recent developments.

Q. Explain how you modified the cost of capacity for the Synapse analysis.

A. I modified the capacity price forecast that the Company provided by applying a percentage decrease in line with the difference observed between APCo's near-term projections and actual prices for the past two auctions. I also relied on a capacity price forecast from S&P Global Market Intelligence that reflects the impact of MOPR and MSOC to inform the long-term price projection (the yellow line in Figure 1 below).[16] According to S&P, "[l]ower peak demand, installed reserve margin requirement and forced outage rates, offset by a higher net cost of new entry, lowered forecast prices marginally, while the market seller offer cap significantly limits the bid potential for generators, resulting in 62%-77% lower forecast capacity prices in the next 10 years compared to previous forecasts."[17]

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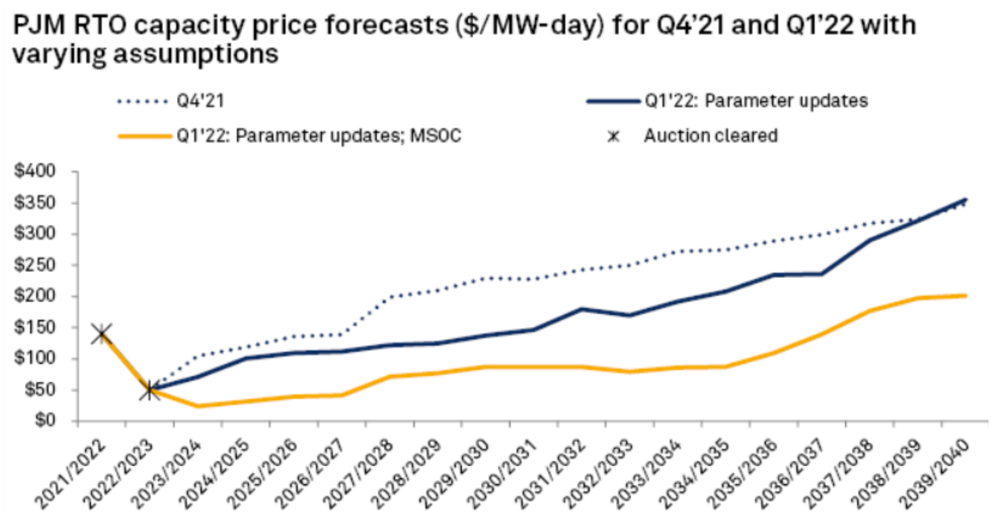
15 PJM Interconnection, *2023/2024 RPM Base Residual Auction Results* (June 2022), available at https://bit.ly/3cr7ElR.

16 Katherine McCaffrey, *PJM Capacity Prices Projected to Drop Due to Auction Parameter, Market Updates*, S&P Global Market Intelligence (May 2022), available at https://bit.ly/3zozWWf.

17 *Id.*

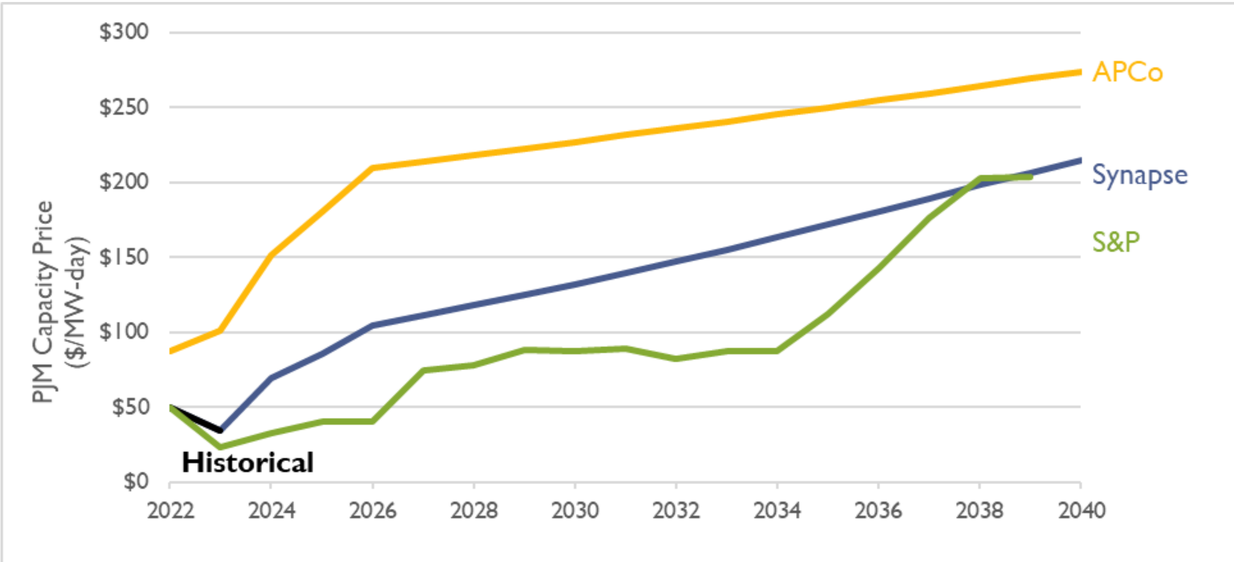
Figure 1. PJM RTO Capacity Price Forecasts ($ / MW-Day)



I also acknowledge that there is a lot of uncertainty around the future of capacity prices in PJM. S&P states: "A significant uncertainty is how individual bidders will react to the new rule and pursue the unit-specific offer cap that may be higher than the default. Therefore, this forecast may be an aggressive implementation of the MSOC and prices may clear higher."[18] I believe the forecast I used represents a plausible future for prices, based on recent historical trends and observed impacts of PJM auction parameters. Overall, the Synapse forecast is more up-to-date and is representative of current market conditions, unlike the one APCo provided. It is also conservative relative to the S&P forecast. I show the Synapse capacity price compared to S&P's and APCo's in Figure 2 below.

18 *Id.*

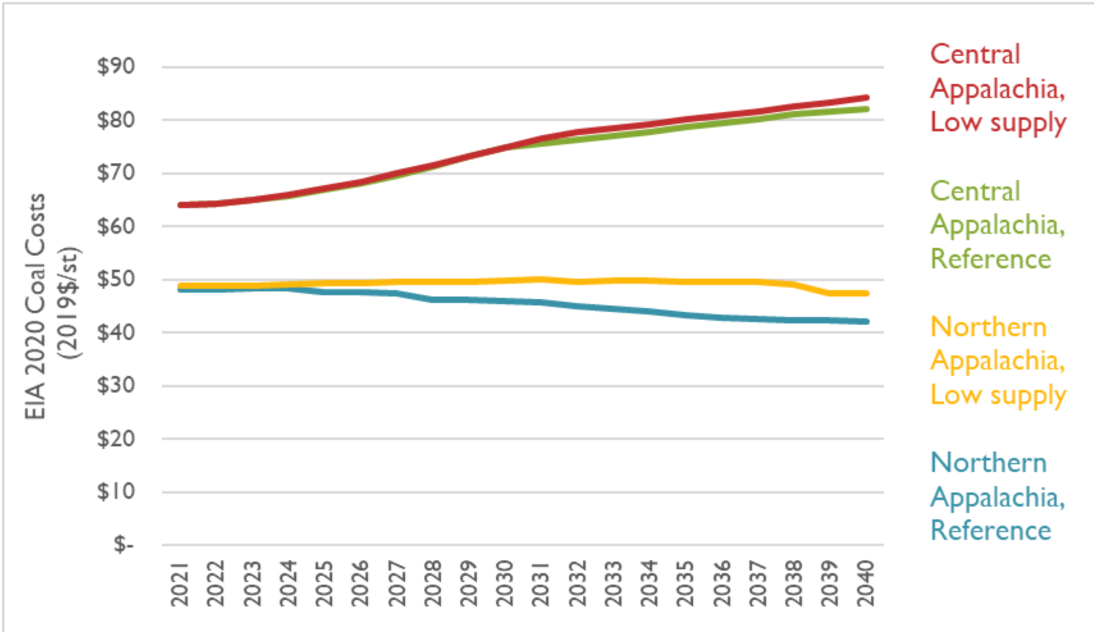
Figure 2. PJM Capacity Price Forecast by Source (Nominal $ / MW-Day)



Q. Did you make any other modifications to APCo's input assumptions?

A. Yes, for the purpose of developing a sensitivity analysis. In Scenario 1b of my modeling, I used a higher coal price cost for Amos and Mountaineer to capture the challenges that the Company may face in procuring the quantity of coal necessary to operate its plants at a 69 percent capacity factor. To estimate what these costs might be, I referenced the coal costs from the low oil and gas supply side case from the Energy Information Administration's 2020 Annual Energy Outlook (EIA AEO), as this was the source the Company relied on in its original forecast. I show these prices in Figure 3 below. I then applied the percentage difference between the reference case and the low oil and gas supply case to the coal costs the Company provided. This resulted in a coal price increase of 2 to 12 percent over the analysis period.

Figure 3. Reference and Low Supply Coal Prices from EIA AEO 2020 (2019$ / ton)



Q. Is it reasonable to assume that the Company will need to pay more per ton for coal in the future than it currently projects if it wants to maintain a 69-percent capacity factor?

A. Yes. The Company has stated in discovery that it has already faced coal shortages at Amos and Mountaineer.[19] The Company has also stated that it is not currently able to procure from its current suppliers the 10 million tons of coal that would be required to operate Amos and Mountaineer at 69 percent capacity factor.[20] This suggests that the Company may have to pay more to secure enough coal in the future.

19 Company Response to Sierra Club Request No. 3-5, attached as Exhibit SK-5.

20 Company Response to Sierra Club Request No. 3-4, attached as Exhibit SK-2.

5. SYNAPSE MODELING RESULTS

Q. What were the results of the Synapse modeling analysis?

A. In the Synapse optimized modeling, I found that removing Amos from the rate base in Virginia would result in cost savings to Virginia customers of $202 million relative to Scenario 1, which represents the West Virginia PSC Preferred Case, as shown in Table 4 below. These results differ from what APCo found based on Company Witness Martin's spreadsheet analysis due in large part to the oversimplifications that APCo relied on in its analysis.

Table 4. NPVRR for the Virginia Jurisdiction by Scenario

	Revenue Requirement for APCo's Virginia Ratepayers		
Scenario	**NPVRR* ($Millions)**	**Delta from West Virginia PSC Preferred ($Millions)**	**Delta from APCo Preferred ($Millions)**
1a. West Virginia PSC Preferred	$5,915	N/A	$173
1b. West Virginia PSC Preferred, high coal price	$6,089	$174	$346
2. APCo Preferred	$5,743	-$173	N/A
3. Full Coal Removal	$5,927	$12	$184
4. Partial Coal Removal	$5,713	-$202	-$30

* *Note: NPVRR numbers do not account for the additional costs caused by REC deficits observed in Scenarios 1 and 2.*

Q. Did you conduct any modeling that used the capacity prices provided by the Company?

A. Yes. I did run some scenarios that used the higher capacity price to test the robustness of my results. Under higher capacity prices, my results showed that removing only Amos from rate base in Virginia still results in net savings to Virginia relative to the West Virginia Preferred Case (see Table 5).

Table 5. NPVRR Results for Scenarios Using APCo's Capacity Price

Scenario	Revenue Requirement for APCo's Virginia Ratepayers, using a higher capacity price forecast		
	NPVRR* ($Millions)	**Delta from West Virginia PSC Preferred ($Millions)**	**Delta from APCo Preferred ($Millions)**
1a. West Virginia PSC Preferred	$5,757	N/A	$173
1b. West Virginia PSC Preferred, high coal price	$5,931	$174	$346
2. APCo Preferred	$5,585	-$173	N / A
3. Full Coal Removal	$6,030	$273	$455
4. Partial Coal Removal	$5,720	-$38	$135

** Note: NPVRR numbers do not account for the additional costs caused by REC deficits observed in Scenarios 1 and 2.*

Q. Do these results indicate that Virginia should approve ELG costs at Mountaineer and continue to operate the plant through 2040?

A. No. Although removing both Amos and Mountaineer did not result in net savings when using a higher capacity price forecast, as I discuss above, these results depend on an unrealistically high capacity price forecast. Additionally, these results rely on conservative assumptions including no future carbon pricing on coal generation. It is likely that between now and 2040, there will be policies that impose a cost on carbon, or other policies with a similar impact that make operating Mountaineer less economic than my results show. Witness Martin stated last year that it is the Company's "basic position that a carbon cost is coming someday; it's just a question of when and how much."[21] I agree with that sentiment and believe it is better for ratepayers to avoid the potential costs that come with being locked into carbon emissions from these plants for the next eighteen years.

Q. Are the WV PSC Preferred and APCo Preferred scenarios VCEA-compliant?

A. No. I had presumed that by relying on the Portfolio 1 resource builds from the RPS Plan, Scenarios 1 and 2 would be VCEA-compliant because Table 31 of the RPS Plan showed that Portfolio 1 would generate enough renewable energy to meet the targets. However, in discovery, the Company stated that Table 31 contained errors, and provided an updated version that showed a projected REC shortfall in many years.[22] Because the Company's RPS Plan was actually not VCEA compliant, and Synapse Scenarios 1 and 2 relied solely on the Portfolio 1 resource builds from the RPS Plan, our baseline scenarios are also not VCEA-compliant.

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21 *Petition of Appalachian Power Company for Approval of Rate Adjustment Clause E-RAC for Costs to Comply with State and Federal Environmental Regulations*, Case No. PUR-2020-00258, Hearing Transcript at 99:18–99:21 (June 23, 2021), available at https://bit.ly/3cDouy1.

22 Company Response to Sierra Club Request No. 2-3, attached as Exhibit SK-6.; SC 2-03 Attachment 14.xlsx. This workbook contains voluminous spreadsheet data in numerous tabs and can be produced upon request. This spreadsheet is known to contain errors, as identified in Company Response to Sierra Club Request 7-4, attached as Exhibit SK-7.

Q. Are the Partial and Full Coal Removal scenarios you modeled VCEA-compliant?

A. Yes, starting in 2024, Synapse Scenarios 3 and 4 are VCEA-compliant. The model was not allowed to add new resources in 2022 and 2023 and has the same generation portfolio as Scenarios 1 and 2. 2024 is the first year I allowed the model to add new resources to the portfolio. Scenarios 3 and 4 were allowed to optimize to build replacement capacity given the removal of Amos and Mountaineer, and, in both cases, the model built enough renewables to meet the RPS targets from 2024 onwards.

Q. Are there costs associated with the Company's REC shortfall that were not included in modeling that could make Scenarios 1 and 2 even more expensive?

A. Yes. Namely, the Company stated that it had not accounted for the cost of REC deficiencies in PLEXOS, as these were identified after the portfolios had been produced.[23] APCo showed its near-term projected shortages in Table 5 of the RPS Plan (reproduced as Table 6 below). Because I used APCo's Portfolio 1 resource builds as the basis for my Scenarios 1 and 2, I also observed a REC deficiency across many years between 2022 and 2040 in those cases.

Table 6. Company's Projected RPS Deficit, from RPS Plan Table 5

	2021	**2022**	**2023**	**2024**	**2025**
RPS Requirement (MWh)	902,433	1,051,191	1,200,202	1,498,967	2,099,828
REC Deficit (MWh)	(16,783)	(76,859)	(208,182)	(354,799)	(422,356)

23 Company Response to Sierra Club Request No. 5-9, attached as Exhibit SK-8.

Furthermore, the Company admitted that it did not properly account for the retirement of the Buck and Byllesby hydro plants at the end of 2024 in its modeling and had not prepared a corrected analysis, further underestimating its RPS compliance shortfall by 74,000 MWh annually beginning in 2025.[24] If the Company does not purchase additional RECs or build renewables to address this shortfall, it will be obligated to pay a deficiency payment of at least $45/MWh per the VCEA. A 74,000-MWh annual shortfall beginning in 2025 through 2040 results in a cost of $35.2 million in NPV terms.

If I had incorporated the REC deficiency cost for the total shortage I observed across the modeling period, it would have increased the NPVRR for Scenarios 1 and 2 relative to Scenarios 3 and 4 by $153 million.

Table 7 below shows the revenue requirements for the scenarios under a future where the Company incurs the deficiency payment for its RPS shortfall in all years. While the Company may elect to procure RECs or install additional renewables at a lower price than $45/MWh, the following numbers show the upper bound of the potential risk of a non-VCEA compliant portfolio.

24 Company Response to Sierra Club Request No. 6-10, attached as Exhibit SK-9.

Table 7. NPVRR Results for Scenarios, Including REC Shortage Penalty of $45 / MWh.

	Revenue Requirement for APCo's Virginia Ratepayers		
Scenario	**NPVRR ($Millions)**	**Delta from West Virginia PSC Preferred ($Millions)**	**Delta from APCo Preferred ($Millions)**
1a. West Virginia PSC Preferred	$6,068	N/A	$173
1b. West Virginia PSC Preferred, high coal price	$6,242	$174	$346
2. APCo Preferred	$5,896	-$173	N/A
3. Full Coal Removal	$5,927	-$141	$31
4. Partial Coal Removal	$5,713	-$355	-$183

Q What are the implications of the VCEA non-compliance of Scenarios 1 and 2 on your modeling results?

A. The cost savings of the Full and Partial Coal Removal scenarios are likely conservative as a result of the non-compliance of the WV PSC Preferred and APCo Preferred scenarios. Synapse Scenarios 3 and 4, which remove one or both of the Plants, are VCEA-compliant, and therefore include all costs associated with complying with the VCEA. If these additional costs associated with RPS compliance were included in Scenarios 1 and 2, the relative cost savings we would find from removing one or both of the Plants would likely be larger than what we found in our modeling results in Table 4.

Q. Why do customers save money in the scenarios where APCo does not approve ELG costs at the Plants compared with the scenarios in which they continue to operate?

A. If the Commission does not approve the ELG costs, Virginia ratepayers will avoid paying for the ELG investment as well as future capital expenditures, fixed operation and maintenance costs, and taxes required maintain both Plants beyond 2028. Aging coal plants are costly to maintain, and while the Company would have to pay for replacement resources if the plants are removed from the Virginia rate base, the cost of these resources would likely be much lower than the costs to keep its coal fleet online.

These future, avoidable, fixed coal plant costs are shown below in Table 8 and would add to both Plants' existing undepreciated balance. Ratepayers would also be able to avoid paying the variable costs of generation, such as fuel and variable operation and maintenance costs, which are higher than the zero-variable cost of renewable alternatives.

Table 8. Annual Avoidable Fixed Costs ($Million)

Year	Amos	Mountaineer	Total
2025	$11.3	$3.0	$14.3
2026	$10.8	$2.9	$13.6
2027	$10.2	$2.8	$13.0
2028	$9.6	$2.7	$12.3
2029	$49.5	$23.1	$72.6
2030	$46.9	$22.3	$69.1
2031	$49.9	$22.9	$72.8
2032	$53.0	$24.2	$77.2
2033	$52.9	$25.6	$78.5
2034	$53.2	$27.0	$80.2
2035	$57.1	$28.5	$85.5
2036	$60.3	$29.6	$90.0
2037	$62.5	$30.4	$92.9
2038	$63.5	$30.8	$94.3
2039	$64.1	$30.9	$95.0
2040	$64.5	$30.4	$94.9

Source: Martin E-RAC Case 1 workpaper 2-7 Final.xlsx. This document contains voluminous spreadsheet data in numerous tabs and can be produced upon request.

Q. What types and quantities of resources are added in Scenarios 1 and 2, where both Plants are assumed to stay online through 2040?

A. In Scenarios 1 and 2, West Virginia PSC Preferred and APCo Preferred, the model builds a combination of mostly wind and solar to meet the Company's RPS requirements. Some hybrid systems and standalone storage are also built. In all years, the Company has excess firm capacity that it can sell, which I represent as negative numbers in Table 9 below.

Table 9. APCo & WV PSC Preferred Cumulative New Capacity Builds (MW) (Virginia Jurisdiction)

Year	New PPA Wind	New Utility Wind	New PPA Solar	New Utility Solar	New Paired Solar	New Battery	New Paired Battery	Capacity Market
2022	-	-	-	-	-	-	-	(75)
2023	-	-	-	-	-	-	-	(66)
2024	-	-	-	-	-	-	-	(72)
2025	-	-	-	-	-	-	-	(374)
2026	100	200	-	-	-	25	-	(315)
2027	100	200	-	-	-	25	-	(326)
2028	200	200	-	-	-	25	-	(337)
2029	250	400	-	-	-	25	-	(347)
2030	350	400	-	-	-	25	-	(342)
2031	350	400	150	150	-	150	-	(532)
2032	350	400	300	150	-	150	-	(575)
2033	350	400	450	300	-	150	-	(654)
2034	350	400	600	300	-	150	-	(695)
2035	350	400	750	300	-	150	-	(735)
2036	350	400	900	600	-	400	-	(1073)
2037	350	400	900	900	-	400	-	(1,155)
2038	350	400	900	1,200	-	400	-	(1,1235)
2039	350	400	900	1,200	219	400	73	(1,368)
2040	350	400	900	1,200	669	400	223	(1,639)

Q. What types and quantities of replacement resources are added in Scenario 3, the Full Coal Removal Scenario?

A. In Scenario 3, the Full Coal Removal scenario, the model builds a combination of PPA wind, company owned and PPA solar, hybrid solar/storage systems, and standalone storage. It also relies on firm capacity purchases from PJM (shown as positive numbers in Table 10 below). In some years, the Company has excess firm capacity that it can sell, which I represent as negative numbers below.

Table 10. Full Coal Removal Scenario Cumulative New Capacity Builds (MW) (Virginia)

Year	New PPA Wind	New PPA Solar	New Utility Solar	New Paired Solar	New Battery	New Paired Battery	Capacity Market
2022	-	-	-	-	-	-	(75)
2023	-	-	-	-	-	-	(66)
2024	120	-	-	30	-	10	(114)
2025	420	-	-	75	-	25	(487)
2026	420	-	-	75	-	25	(362)
2027	420	-	-	120	-	40	(401)
2028	420	10	-	165	-	55	(430)
2029	420	230	-	210	-	70	1,416
2030	420	460	-	255	65	85	1,296
2031	420	630	-	300	65	100	1,250
2032	420	790	-	345	65	115	1,179
2033	420	970	-	390	65	130	1,105
2034	420	1,140	-	435	65	145	1,033
2035	420	1,440	-	480	240	160	769
2036	420	1,740	100	525	240	175	645
2037	420	1,780	100	570	240	190	605
2038	420	2,080	100	615	240	205	499
2039	420	2,330	100	660	240	220	401
2040	420	2,540	100	705	240	235	310

Q. What types and quantities of replacement resources are added in Scenario 4, the Partial Coal Removal Scenario?

A. In Scenario 4, the Partial Coal Removal scenario, the model builds the same combination of PPA wind, owned and PPA solar, hybrid solar/storage systems, and standalone storage as Scenario 3. The main difference is a lower reliance on firm capacity purchases from PJM (shown as positive numbers in the table below). In some years, the Company has excess firm capacity that it can sell, which I represent as negative numbers in Table 11.

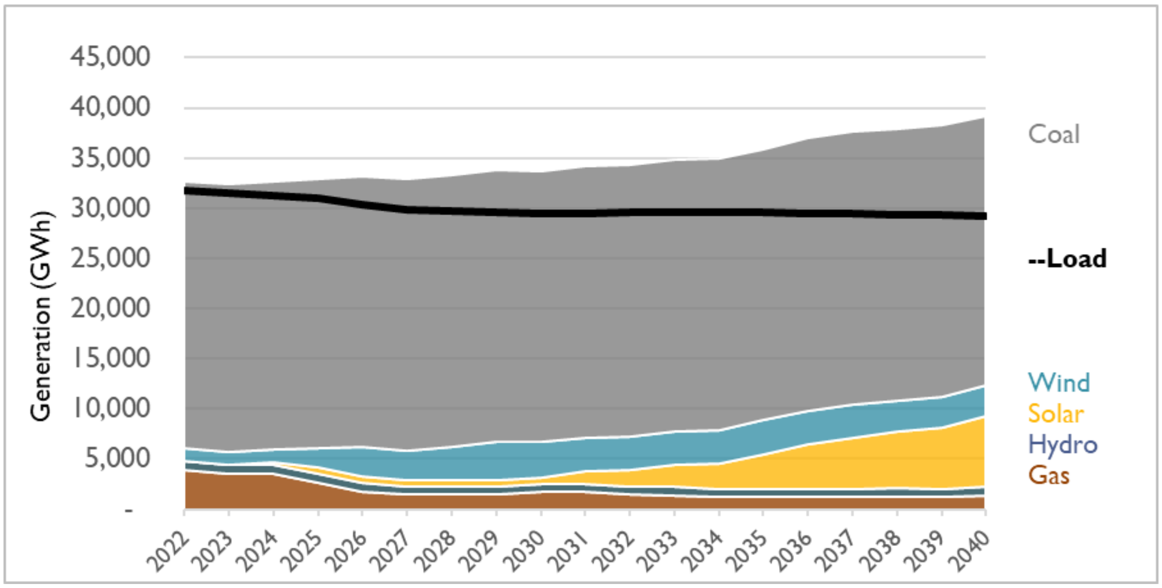
Table 11. Partial Coal Removal Scenario Cumulative New Capacity Builds (MW) (Virginia)

Year	New PPA Wind	New PPA Solar	New Utility Solar	New Paired Solar	New Battery	New Paired Battery	Capacity Market
2022	-	-	-	-	-	-	(75)
2023	-	-	-	-	-	-	(66)
2024	120	-	-	30	-	10	(114)
2025	420	-	-	75	-	25	(487)
2026	420	-	-	75	-	25	(362)
2027	420	-	-	120	-	40	(401)
2028	420	10	-	165	-	55	(430)
2029	420	230	-	210	-	70	821
2030	420	460	-	255	65	85	701
2031	420	630	-	300	65	100	655
2032	420	790	-	345	65	115	584
2033	420	970	-	390	65	130	510
2034	420	1,140	-	435	65	145	438
2035	420	1,440	-	480	240	160	174
2036	420	1,740	100	525	240	175	50
2037	420	1,780	100	570	240	190	10
2038	420	2,080	100	615	240	205	(96)
2039	420	2,330	100	660	240	220	(194)
2040	420	2,540	100	705	240	235	(285)

Q. How does modeled generation compare between the Synapse modeling scenarios?

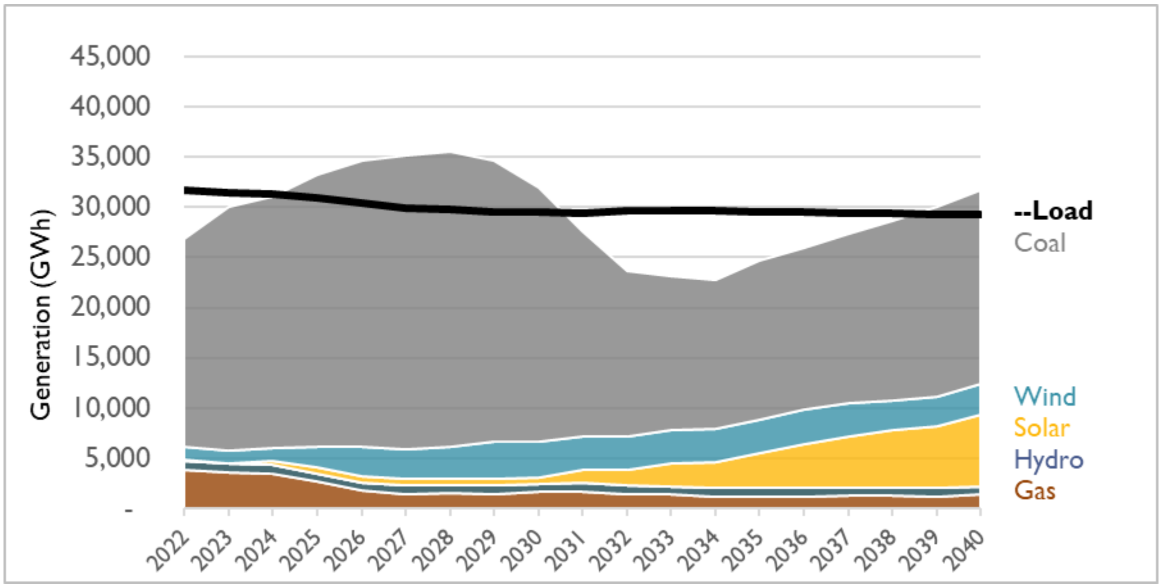
A. In Scenario 1, the West Virginia PSC Preferred cases, both Plants operate at an annual capacity factor of 69 percent each year through 2040. In these scenarios, the Company has excess energy to export to the market throughout the analysis period, which is represented by the amount of generation above the load requirement line in Figure 4.

Figure 4. Generation in Scenario 1, West Virginia PSC Preferred Case



In Scenario 2, the APCo Preferred case, the Company's results show generation at APCo's thermal units, including both Amos and Mountaineer, increasing between 2022 and 2028, after which generation falls until 2032 and then grows more slowly until the units retire at the end of 2040. The Company relies on some imports to meet load through 2024, sells excess energy to the market between 2025 and 2030, and again relies on imports between 2031 and 2038. Those patterns are shown below in (the now-unredacted) Figure 5.[25]

Figure 5. Generation in Scenario 2, APCo Preferred Case



In both Scenarios 3 and 4, the Full and Partial Coal Removal Cases, I assume that coal generation would align with the profile observed in the APCo Preferred case up through 2028. After 2028, one or both plants are then removed from Virginia's rate base and replaced by renewables and imports. This results in the West Virginia jurisdiction of APCo having excess energy from its ownership of the full Amos and Mountaineer plants. The results from these scenarios are shown in Figure 6 and Figure 7 below.

25 *See* SC 2-02 CONFIDENTIAL Attachment 1.xlsx. Although the Company has classified this attachment as confidential, it has confirmed with the Club that only specific cost and operational data for individual units is protected under the Hearing Examiner's protective rulings. This document contains voluminous spreadsheet data in numerous tabs and can be produced upon request.

Figure 6. Generation in Scenario 3 Full Coal Removal Case

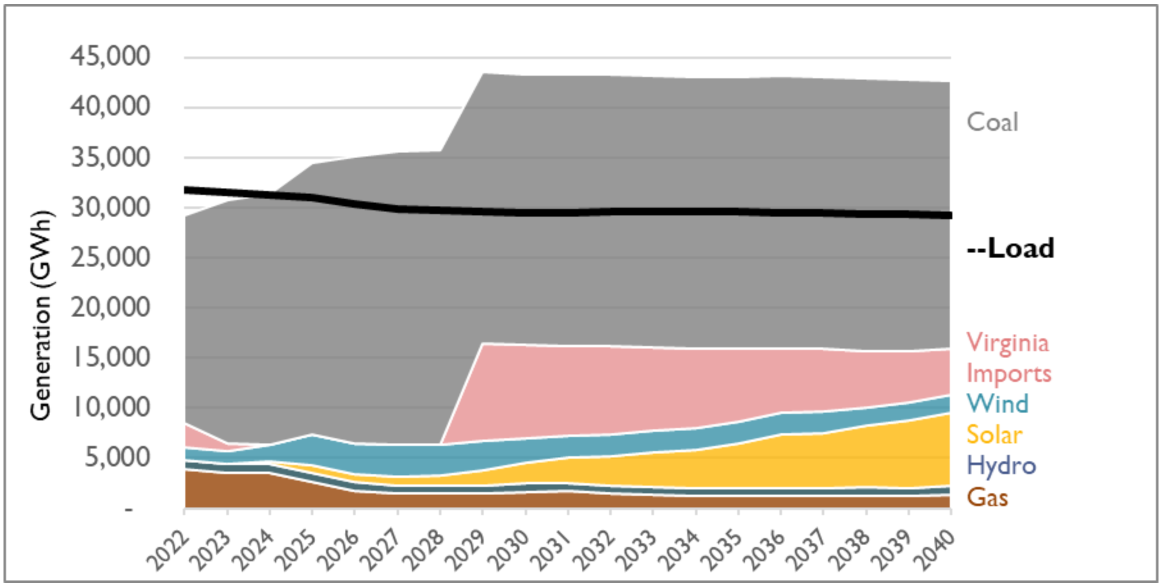
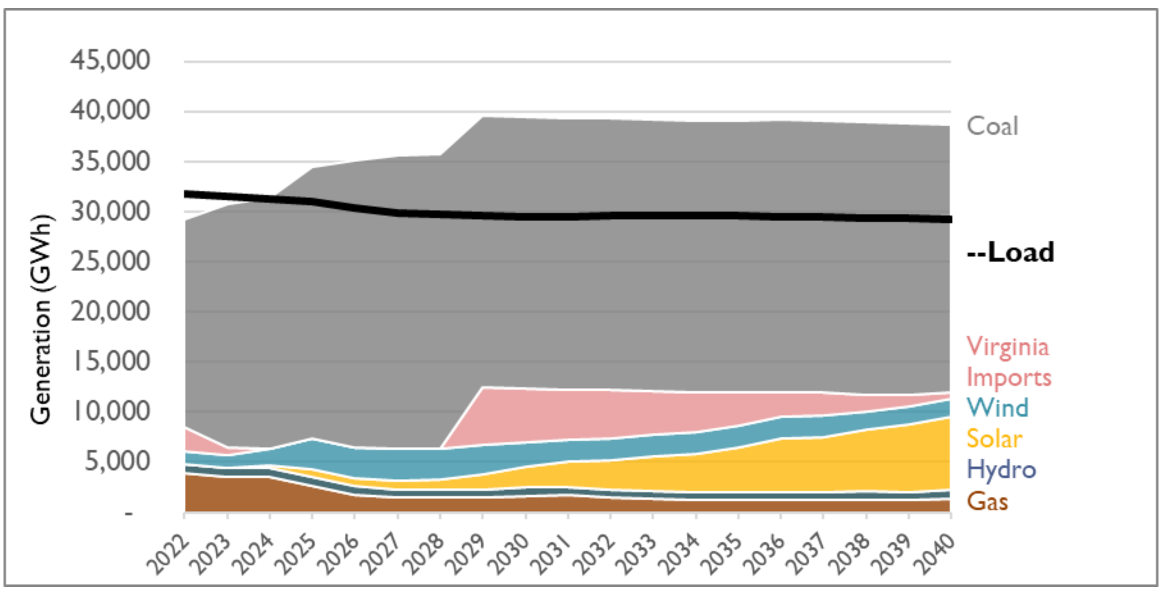


Figure 7. Generation in Scenario 4 Partial Coal Removal Case



Q. Is it reasonable for the Company to rely on the PJM market for energy and capacity needs?

A. Yes. The PJM capacity market is well-established and has existed for over fifteen years. The "Rest of RTO" zone where APCo is located has always been the least-constrained zone in which to procure or sell capacity, meaning it is generally the lowest-priced zone. As seen in Tables 10 and 11, the coal removal scenarios rely on the market only to the extent necessary to meet reserve needs, and that reliance steadily declines over time as renewable and storage resources are built. Additionally, the Company acknowledges that there is no requirement that a certain amount of load be served by Company resources.[26]

Q. What should the Commission conclude from the Synapse modeling analysis?

A. There are several important takeaways from the Synapse modeling analysis. First, that the removal of Amos from the Virginia rate base in 2028 has been shown to be the least-cost scenario and is in the best interests of Virginia ratepayers because it saves more than $202 million between 2022 and 2040. Second, after accounting for the impact of recent PJM policies lowering capacity market prices, the risks of REC deficiencies and VCEA non-compliance, as well as future carbon policies that could make coal generation even less economic, the relative benefits of removing both Amos and Mountaineer from the Virginia rate base increase substantially.

6. LOCKING RATEPAYERS INTO COAL PLANTS THAT HAVE BEEN ORDERED TO RUN AT A 69 PERCENT CAPACITY FACTOR REGARDLESS OF ECONOMICS IS RISKY AND COULD LEAD TO UNNECESSARY NET OPERATIONAL LOSSES

Q. Explain the recent developments in West Virginia that relate to the operation of Amos and Mountaineer.

A. The West Virginia PSC entered an Order on September 2, 2021 that mandated: "The capacity factor for [Amos and Mountaineer] should be 69 percent in this case with the

26 Company Response to Sierra Club Request No. 5-10, attached as Exhibit SK-10.

potential for an increased capacity factor as described in this Order."[27] While the Company has argued that this issue is still pending before the West Virginia Commission, it is possible that APCo will be required to dispatch the Plants uneconomically to force both plants to operate at this high capacity factor to comply with this ruling.[28]

Q. Has the Company produced any analysis that considers this 69 percent capacity factor determination?

A. No, the Company admitted that it has not created any analysis that reflects a future where both Plants are required to run at least at a 69-percent capacity factor.[29]

Q. At what capacity factors have both Plants historically been operating?

A. Amos Units 1 through 3 have been operating between a 31 to 57 percent annual capacity factor over the past 5 years as shown in Figure 8 below.[30] This is much lower than 69 percent. Mountaineer has operated between a 49- and 71-percent capacity factor over the past five years as shown in Figure 9 below.[31] Company data for performance through May 2022 stated generally lower capacity factors across all four units of 20 to 49 percent.[32]

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27 *Petition of Appalachian Power Company & Wheeling Power Company to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect*, West Virginia Public Service Commission Case No. 21-0339-E-ENEC, Commission Order (September 2, 2021), available at https://bit.ly/3J8lt51.

28 Company Response in Opposition to Sierra Club's Motion to Compel Discovery at 7.

29 *Id.* at 9.

30 *See* Company Response to Sierra Club Discovery Request No. 6-1 – Attachment 1, attached as Exhibit SK-11.

31 *Id.*

32 *Id.*

Figure 8: Amos Historical Capacity Factors

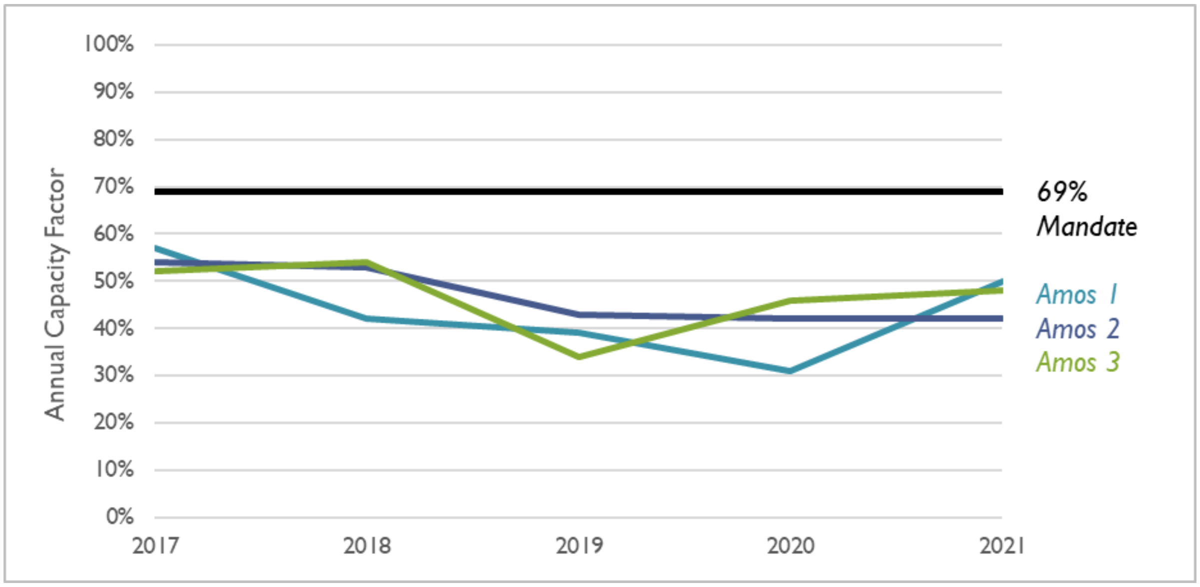
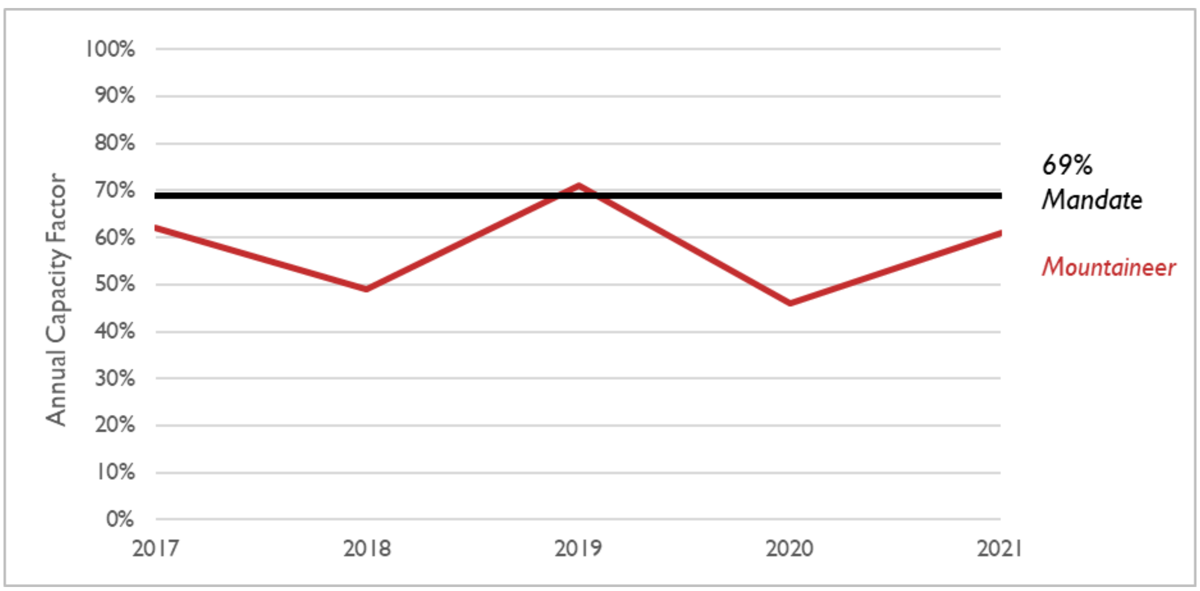


Figure 9: Mountaineer Historical Capacity Factors



Q. What will happen if both Plants are mandated to run at a 69-percent capacity factor?

A. The Company will likely need to self-commit both Plants in the PJM market a higher percentage of the time to ensure that they are dispatched at their minimum operating levels. This means that even if both Plants' costs are higher than market prices, they will be forced to generate. When costs per megawatt-hour are higher than revenues earned in the energy market, APCo loses money and ratepayers will be forced to bear those unnecessary costs. Given the potential costs this self-commitment practice could pass on to Virginia ratepayers, this risk should be fully taken into consideration when evaluating whether Virginia should approve the ELG costs at both Plants.

7. COAL-FIRED POWER PLANTS WILL BECOME INCREASINGLY UNECONOMIC IN THE FUTURE

Q. What does the future look like for coal-fired generating units in the United States and in the PJM region?

A. Existing coal-fired generating units will become even less economic than they are today, because of both economic and regulatory forces that will increase the costs of operation at coal units relative to other types of capacity. Between 2016 and 2020, around 11 GW of coal retired each year in the United States. Although the levels dropped to 4.6 GW in 2021, an additional 12.7 GW of coal generation is scheduled to retire in 2022.[33] Looking beyond 2022, S&P Global Market Intelligence stated that 51 GW of coal power is scheduled to retire between 2022 and 2027, with an additional 23 GW of retirements coming in 2028.[34]

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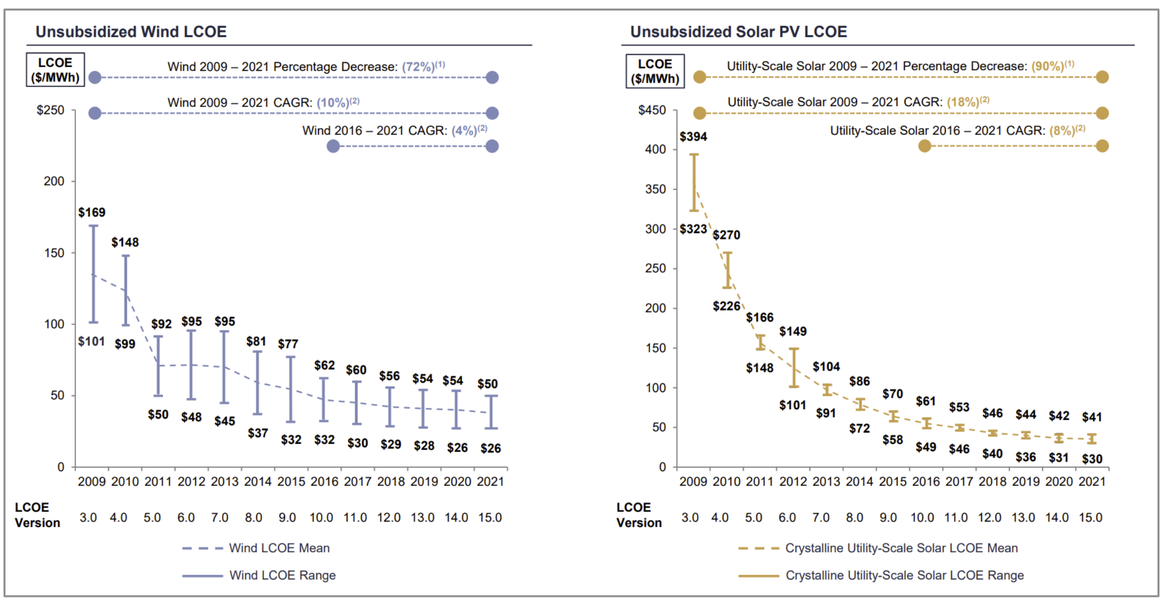
33 U.S. Energy Information Administration, *Coal Will Account for 85% of U.S. Electric Generating Capacity Retirements in 2022* (January 11, 2022), available at https://bit.ly/3MPZ4KE.

34 Darren Sweeney et al., *More than 23 GW of Coal Capacity to Retire in 2028 as Plant Closures Accelerate*," S&P Global Market Intelligence (February 2022), available at https://bit.ly/3vzVpKL.

Q. Explain how renewables have become a driving factor in coal-plant retirements.

A. The costs of clean generation technologies have fallen dramatically over the previous decade. On an LCOE basis, costs for wind are now 72% lower than the costs in 2009, with a compound annual rate of decline of 10% per year. Costs for solar are now 90% lower than in 2009, with a compound annual rate of decline of 18 percent per year. Those annual trends are shown in Figure 10. While prices for renewables have gone up in the past year, analysts at Bloomberg New Energy Finance have stated that they foresee a return to long-term technology cost decline trajectories as demand continues to be strong, supply-chain pressures ease, and production capacity (particularly in China) comes back online.[35]

Figure 10: Historical Levelized Cost of Energy for Wind and Solar PV Technologies



Source: LAZARD, *Levelized Cost of Energy Analysis (Version 15.0 October 2021), available at https://bit.ly/3wxCJMl.*

35 David Baker, *Renewable Power Costs Rise, Just Not as Much as Fossil Fuels*, BLOOMBERG (June 2022), available at https://bloom.bg/3cG8Emt.

Q. What are the regulatory forces that challenge the operation of existing units?

A. One such regulatory force is the increase of RPS policies in neighboring PJM states. The volume of zero-variable cost resources on the grid in PJM will increase in future years as neighboring states increase their renewable energy targets, implement more stringent targets for carbon dioxide emissions reductions, or both. In 2018, for example, New Jersey increased its RPS to 50 percent by 2030.[36] In 2019, Maryland legislators passed a bill that also increases its RPS to 50 percent by 2030.[37] The District of Columbia increased its RPS to 100 percent renewable energy by 2040.[38] The locational marginal price for energy will decline as a greater number of these renewable generators come online, further lowering energy revenues earned by coal units.

Q. Are there other relevant regulatory forces?

A. Yes, almost certainly, though we do not yet know what they will look like. President Biden has announced the goal of net-zero carbon dioxide emissions on the country's power grid by 2035. There are no policies currently in place that are explicitly intended to achieve this goal; however, it might be assumed that they will consist of a combination of incentives for zero-carbon energy and additional costs for fossil-fueled generators.

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36 U.S. Energy Information Administration, *Today in Energy: Updated Renewable Portfolio Standards Will Lead to More Renewable Electricity Generation* (February 27, 2019), available at https://bit.ly/3wBLwgi.

37 Catherine Morehouse, *Maryland 50% RPS Bill Doubles Offshore Wind Target, Expands Solar-Carve Out,* Utility Dive (April 10, 2019), available at https://bit.ly/3luJ4SB.

38. Robert Walton, *DC Eases Path for Renewable Generators as it Pursues 100% Goal,* Utility Dive (February 13, 2019), available at https://bit.ly/39JDRU4.

8. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions.

A. First, I find that the Company's analysis was insufficient to support APCo's application. Specifically, the Company did not utilize an optimized capacity expansion and dispatch model and instead relied on an overly simplified capacity replacement analysis. The Company calculated the cost of immediately replacing 100 percent of Virginia's share of the Plants' capacity by 2029, instead of modeling the optimal replacement of only the firm capacity that Virginia's system would need to meet its reserve margin, while also meeting Virginia's RPS goals. The Company also used an unreasonably high estimate for capacity prices in the relevant PJM market zone, given structural market changes and historical patterns for that zone.

Second, my independent modeling demonstrates that it is uneconomic, and not in the best interest of Virginia ratepayers, for APCo to invest in ELG compliance costs at Amos, which would allow it to continue running the plant through 2040. Removing Amos from the Virginia rate base beginning in 2029 will result in a NPV of savings of at least $202 million through 2040.

While these results indicate ratepayers *may* be better off removing only Amos from the rate base, other risk factors associated with longer-term dependency on coal generation indicate that removal of both plants from APCo Virginia's rate base is likely prudent. When considering the additional risk of potential carbon cost liabilities and the effect of possibly higher coal prices, the marginal value of Mountaineer shrinks. RPS requirement shortfalls associated with the West Virginia PSC and APCo Preferred scenarios increase the net value of the coal removal scenarios, resulting in additional cost savings to Virginia ratepayers in the coal removal scenarios.

Q. Please summarize your primary recommendation.

A. Based on my analytical findings above and as described in further detail in this testimony, I recommend that the Commission deny Virginia's share of the costs associated with ELG compliance at Amos and at Mountaineer.

Q. Does this conclude your direct testimony?

A. Yes.

DIRECT TESTIMONY OF SHELLEY KWOK

INDEX OF EXHIBITS

No.	Exhibit	Confidentiality
SK-1	Resume of Shelley Kwok	Public
SK-2	Company Response to Sierra Club Discovery Request No. 3-4	Public
SK-3	Company Response to Sierra Club Discovery Request No. 6-4	Public
SK-4	Company Response to Sierra Club Request No. 2-21 – Attachment 1	Public
SK-5	Company Response to Sierra Club Discovery Request No. 3-5	Public
SK-6	Company Response to Sierra Club Discovery Request No. 2-3	Public
SK-7	Company Response to Sierra Club Discovery Request No. 7-4	Public
SK-8	Company Response to Sierra Club Discovery Request No. 5-9	Public
SK-9	Company Response to Sierra Club Discovery Request No. 6-10	Public
SK-10	Company Response to Sierra Club Discovery Request No. 5-10	Public
SK-11	Company Response to Sierra Club Request No. 6-1 – Attachment 1	Public

EXHIBIT SK-1

Resume of Shelley Kwok

Shelley Kwok, Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7046
skwok@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Associate,* June 2021 – Present; *Research Associate,* August 2019 – June 2021.

- Conducts research and provides consulting on energy sector issues.
- Develops Excel-based spreadsheet models to conduct cash flow analyses and utility performance metrics assessments.
- Performs analysis using capacity expansion and dispatch models to support a wide array of projects.
- Assists in writing expert testimony and reports related to power plant economics and utility Integrated Resource Planning.
- Conducts analysis to evaluate energy efficiency programs and policies.
- Co-developer of Synapse's Building Decarbonization Calculator (BDC), a stock flow model to calculate the emissions and load impacts of heat pump adoption.

Tufts Department of Mechanical Engineering, Medford, MA. *Energy Research Fellow*, September 2018 - July 2019

- Utilized the SWITCH capacity expansion model to create optimized power systems projections.
- Incorporated national rooftop PV potential data from Google Project Sunroof into an energy model database.
- Modeled the electric sector to quantify the effects of installing residential solar at optimized rooftop orientations.
- Developed Python code to manipulate data and create data visualizations.

Integral Group, Oakland, CA. *Intern*, June 2018 – August 2018

- Collaborated with coworkers to design sustainable HVAC systems for Net-Zero Energy and LEED-certified buildings and performed engineering calculations to support building designs.
- Utilized EnergyPlus and OpenStudio to create energy models and provided recommendations for implementing energy efficiency measures.
- Modeled HVAC systems using Revit.

Renewable Energy and Applied Photonics Lab, Medford, MA. *Research Assistant.* February 2017 – May 2017

- Refurbished thermal evaporators to be used for thin film plating on solar wafers.

EDUCATION

Tufts University, Medford, MA

Bachelor of Science in Mechanical Engineering, *Magna Cum Laude*, 2019.

SKILLS

Computer Software: EnCompass, Excel, Python, R, C++, MATLAB

PUBLICATIONS

Hopkins, A. S., A. Napoleon, S. Kwok. 2022. *Factsheet: Hydrogen & Low-Carbon Gases in New York's Electricity Future*. Synapse Energy Economics for Sierra Club.

Hopkins A. S., P. Eash-Gates, J. Frost, S. Kwok, J. Litynski, K. Takahashi. "Decarbonization of Buildings." In *San Diego Regional Decarbonization Framework*, edited by SDG Policy Initiative, School of Global Policy and Strategy, University of California San Diego. March 2022.

Glick, D., S. Kwok. 2021 *Review of Southwestern Public Service Company's 2021 IRP and Tolk Analysis.* Synapse Energy Economics for Sierra Club.

Frost, J. S. Kwok, K. Takahashi, A.S. Hopkins, A. Napoleon. 2021. *New York Heat Pump Trajectory Analysis*. Synapse Energy Economics for NRDC.

Eash-Gates, P., D. Glick, S. Kwok, J. Tabernero, R. Wilson. 2021. *A Clean Energy Future for Tampa*. Synapse Energy Economics for Sierra Club.

Takahashi, K., T. Woolf, B. Havumaki, D. White, D. Goldberg, S. Kwok, A. Takasugi. 2021. *Missed Opportunities: The Impacts of Recent Policies on Energy Efficiency Programs in Midwestern States.* Synapse Energy Economics for the Midwest Energy Efficiency Alliance.

Kallay, J., S. Letendre, T. Woolf, B. Havumaki, S. Kwok, A. Hopkins, R. Broderick, R. Jeffers, K. Jones, M. DeMenno. 2021. *Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments.* Synapse Energy Economics for Sandia National Laboratories.

Hopkins, A., S. Kwok, A. Napoleon, C. Roberto, K. Takahashi. 2021. *Scoping a Future of Gas Study*. Synapse Energy Economics for Conservation Law Foundation.

Lane, C., S. Kwok, J. Hall, I. Addleton. 2021. *Macroeconomic Analysis of Clean Vehicle Policy Scenarios for Illinois*. Synapse Energy for the Natural Resources Defense Council.

Eash-Gates, P., K. Takahashi, D. Goldberg, A.S. Hopkins, S. Kwok. 2021. *Boston Building Emissions Performance Standard: Technical Methods Overview.* Synapse Energy Economics for the City of Boston.

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

Takahashi, K., A. Hopkins, J. Rosenkrantz, D. White, S. Kwok, N. Garner. 2020. *Assessment of National Grid's Long-Term Capacity Report*. Synapse Energy Economics for the Eastern Environmental Law Center.

Allison, A., S. Kwok. 2020. *Comments on PacifiCorp's 2019 Integrated Resource Plan*. Synapse Energy Economics for the Sierra Club.

White, D., K. Takahashi, M. Whited, S. Kwok, D. Bhandari. 2019. *Memphis and Tennessee Valley Authority: Risk Analysis of Future TVA Rates for Memphis.* Synapse Energy Economics for Friends of the Earth.

Resume updated July 2022

EXHIBIT SK-2

Company Response to Sierra Club Discovery Request No. 3-4

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production
of Documents by the SIERRA CLUB
Sierra Club Set 3
To Appalachian Power Company

Interrogatory Sierra Club 3-04:

Regarding the Company's procurement of coal in the future:
(a) Please state whether the Company has conducted any research into the price impact of procuring the amount of coal necessary to generate at a 69% capacity factor.
(i) If so, please provide all such research.
(ii) If not, please state why not.
(b) Please provide the Company's estimate of the quantity of coal it will need to operate each of Amos and Mountaineer at a 69% capacity factor over the next decade.
(c) Please state whether the Company can procure coal sufficient to operate Amos and Mountaineer at a 69 percent capacity factor from its current suppliers.

Response Sierra Club 3-04:

(a) The Company has not conducted any research into the price impact of procuring amounts of coal necessary to achieve a 69% capacity factor at its coal units because it is currently experiencing difficulty procuring coal. See also the Company's response to SC 2-4.
(b) About 10 million tons a year.
(c) Not at this time.

The foregoing response is made by William K. Castle, Dir Regulatory Svcs, on behalf of Appalachian Power Company.

EXHIBIT SK-3

Company Response to Sierra Club Discovery Request No. 6-4

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 6
To Appalachian Power Company

Interrogatory SC 6-04:

Please refer to the Company's response to Sierra Club Request No. 2-22:

a. When was this Fundamentals Forecast created?
b. Has the Company developed an updated capacity price forecast since this Fundamentals Forecast was created?
    i. If yes, please provide the forecast with the date when it was created.
    ii. If no, please explain whether the changes to the PJM capacity market minimum offer price rule impacts the accuracy of the capacity prices included in the most recent fundamentals forecast.

Response SC 6-04:

a. The Fundamentals Forecast was created in July 2021.
b. No, the Company does not have an updated capacity price forecast since the July 2021 Fundamentals forecast. It is too early to know whether the change in PJM's minimum offer price rule would impact the accuracy of the Company's Fundamentals forecast.

The foregoing response is made by James F. Martin, Dir Resource Planning Strategy, on behalf of Appalachian Power Company.

EXHIBIT SK-4

Company Response to Sierra Club Request No. 2-21 – Attachment 1

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 2
To Appalachian Power Company

Interrogatory Sierra Club 2-21:

Please provide the Fundamentals Forecast used in Witness Martin's referenced PLEXOS analysis in JFM Schedule 1- VCEA Report.

Response Sierra Club 2-21:

See SC 2-21 Attachment 1.

The foregoing response is made by James F. Martin, Dir Resource Planning Strategy, on behalf of Appalachian Power Company.

2021H2 Nom Base RGGI_$15CO2

	Power Prices ($/MWh) -Nominal $'s							
	PJM_AEP		SPP_Central		SPP_KSMO		ERCOT_NORTH	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2021	24.71	20.32	21.26	17.34	21.34	17.35	0.00	0.00
2022	25.72	20.99	21.89	17.80	21.97	17.81	0.00	0.00
2023	26.02	21.22	22.83	18.46	22.91	18.45	0.00	0.00
2024	26.94	21.97	23.90	19.12	23.96	19.09	0.00	0.00
2025	28.35	23.60	25.65	20.24	25.63	20.16	0.00	0.00
2026	29.79	25.24	27.70	21.49	27.60	21.36	0.00	0.00
2027	31.10	26.56	29.32	22.38	29.15	22.23	0.00	0.00
2028	41.42	35.13	39.55	32.80	39.47	32.66	0.00	0.00
2029	41.12	35.26	39.85	33.37	39.81	33.24	0.00	0.00
2030	40.73	35.13	40.33	34.08	40.25	33.95	0.00	0.00
2031	39.89	34.94	40.64	34.66	40.45	34.51	0.00	0.00
2032	39.59	35.24	41.18	35.53	40.91	35.32	0.00	0.00
2033	40.54	36.55	42.25	36.80	41.93	36.54	0.00	0.00
2034	41.18	37.60	43.35	38.12	43.02	37.86	0.00	0.00
2035	41.79	38.21	44.14	38.89	43.80	38.64	0.00	0.00
2036	42.82	39.13	45.19	39.84	44.84	39.55	0.00	0.00
2037	44.20	40.49	46.39	41.14	46.09	40.86	0.00	0.00
2038	45.79	41.93	47.93	42.57	47.55	42.23	0.00	0.00
2039	46.86	42.93	48.96	43.64	48.58	43.31	0.00	0.00
2040	48.70	44.40	50.67	45.02	50.24	44.63	0.00	0.00
2041	49.61	45.41	51.74	46.13	51.27	45.75	0.00	0.00
2042	50.97	46.67	52.88	47.25	52.55	46.99	0.00	0.00
2043	52.31	48.00	54.28	48.55	53.86	48.22	0.00	0.00
2044	53.84	49.32	55.74	49.73	55.38	49.50	0.00	0.00
2045	56.34	50.95	58.13	51.25	57.82	51.12	0.00	0.00
2046	58.62	52.78	60.44	53.07	60.12	52.95	0.00	0.00
2047	60.98	54.67	62.76	54.85	62.45	54.76	0.00	0.00
2048	64.59	56.61	66.10	56.45	65.92	56.53	0.00	0.00
2049	67.92	58.58	69.65	58.74	69.43	58.74	0.00	0.00
2050	69.57	60.73	70.89	60.54	70.84	60.70	0.00	0.00
2051	72.78333333	62.05916667	73.37583333	61.42416667	73.52916667	61.6825	0	0

ERCOT_South		ERCOT_West		12395 Btu/lb 1.6# SO2	12500 Btu/lb 1.6# SO2	12000 Btu/lb 1.2# SO2	12000 Btu/lb 1.67# SO2
On-Peak	Off-Peak	On-Peak	Off-Peak	CAPP	CAPP CSX-Rail	CAPP Compliance	CAPP NYMEX
0.00	0.00	0.00	0.00	59.63	59.63	67.32	59.63
0.00	0.00	0.00	0.00	62.28	62.28	69.32	62.28
0.00	0.00	0.00	0.00	64.56	64.56	71.67	64.56
0.00	0.00	0.00	0.00	66.98	66.98	74.30	66.98
0.00	0.00	0.00	0.00	69.39	69.39	77.23	69.39
0.00	0.00	0.00	0.00	71.90	71.90	80.59	71.90
0.00	0.00	0.00	0.00	74.48	74.48	84.34	74.48
0.00	0.00	0.00	0.00	77.13	77.13	88.46	77.13
0.00	0.00	0.00	0.00	79.80	79.80	92.80	79.80
0.00	0.00	0.00	0.00	82.42	82.42	96.97	82.42
0.00	0.00	0.00	0.00	85.09	85.09	100.33	85.09
0.00	0.00	0.00	0.00	87.86	87.86	103.57	87.86
0.00	0.00	0.00	0.00	90.61	90.61	106.90	90.61
0.00	0.00	0.00	0.00	93.76	93.76	110.35	93.76
0.00	0.00	0.00	0.00	96.92	96.92	113.89	96.92
0.00	0.00	0.00	0.00	100.14	100.14	117.58	100.14
0.00	0.00	0.00	0.00	103.45	103.45	121.41	103.45
0.00	0.00	0.00	0.00	106.86	106.86	125.30	106.86
0.00	0.00	0.00	0.00	110.40	110.40	129.03	110.40
0.00	0.00	0.00	0.00	114.01	114.01	133.00	114.01
0.00	0.00	0.00	0.00	117.72	117.72	137.47	117.72
0.00	0.00	0.00	0.00	121.10	121.10	142.22	121.10
0.00	0.00	0.00	0.00	123.56	123.56	146.57	123.56
0.00	0.00	0.00	0.00	126.84	126.84	151.07	126.84
0.00	0.00	0.00	0.00	130.91	130.91	155.98	130.91
0.00	0.00	0.00	0.00	135.24	135.24	161.07	135.24
0.00	0.00	0.00	0.00	139.76	139.76	166.28	139.76
0.00	0.00	0.00	0.00	144.65	144.65	171.91	144.65
0.00	0.00	0.00	0.00	150.00	150.00	178.02	150.00
0.00	0.00	0.00	0.00	155.09	155.09	183.83	155.09
0	0	0	0	158.1769407	158.1769407	187.461735	158.1769407

Coal ($/ton) FOB -Nominal $'s

12500 Btu/lb 6# SO2 NAPP High Sulfur	13000 Btu/lb 4# SO2 NAPP Med Sulfur	11512 Btu/lb 4.3# SO2 I-Basin	8800 Btu/lb 0.8# SO2 PRB 8800	8400 Btu/lb 0.8# SO2 PRB 8400	11700 Btu/lb 0.9# SO2 Colorado	Henry Hub
50.50	52.93	46.01	12.50	12.50	42.89	2.62
51.95	54.61	46.94	12.73	12.73	44.13	2.68
53.30	56.36	47.44	13.07	13.07	45.28	2.78
54.48	57.73	47.91	13.43	13.43	46.36	2.95
55.08	57.98	48.40	13.82	13.82	47.43	3.27
56.17	59.17	48.98	14.20	14.20	48.56	3.63
57.21	60.60	49.60	14.56	14.56	49.72	3.90
57.46	62.00	50.12	14.90	14.90	50.91	4.11
58.47	63.38	50.37	15.25	15.25	52.10	4.22
59.57	64.70	51.40	15.58	15.58	53.29	4.26
60.54	66.01	52.63	15.91	15.91	54.48	4.29
60.91	67.29	53.83	16.23	16.23	55.62	4.42
61.70	68.47	55.05	16.63	16.63	56.76	4.60
62.28	68.81	56.16	17.10	17.10	57.99	4.77
62.60	68.74	57.27	17.61	17.61	59.35	4.86
63.47	69.83	58.38	18.16	18.16	60.83	4.96
64.53	71.28	59.68	18.71	18.71	62.40	5.14
65.59	72.63	60.87	19.22	19.22	64.04	5.30
66.81	74.16	62.19	19.57	19.57	65.73	5.43
68.01	75.60	63.37	19.93	19.93	67.47	5.56
69.30	77.32	64.57	20.35	20.35	69.29	5.68
70.60	80.05	65.96	20.81	20.81	71.16	5.85
72.08	85.23	67.36	21.36	21.36	72.99	6.02
73.44	88.26	68.66	21.90	21.90	74.85	6.18
74.64	90.85	70.15	22.45	22.45	76.83	6.37
75.74	93.09	71.58	22.98	22.98	78.91	6.58
76.76	95.39	73.13	23.57	23.57	81.12	6.82
77.73	97.86	74.71	24.20	24.20	83.45	7.05
78.62	101.04	76.28	24.81	24.81	85.87	7.27
79.53	105.13	77.86	25.39	25.39	88.17	7.54
80.89445417	107.3306209	79.28074843	25.85741643	25.85741643	89.85038605	7.675590714

Natural Gas ($/mmbtu) -Nominal $'s							Uranium Fuel UO2 ($/mmbtu) - Nominal $'s
TCO Pool	Dominion South Point Pool	TCO Deliv	HSC	PEPL TX-OK	Swing Service Adder		
2.37	2.30	2.62	2.54	2.31	0.27		0.96
2.43	2.36	2.68	2.60	2.37	0.28		0.99
2.51	2.42	2.76	2.71	2.42	0.29		1.01
2.63	2.53	2.89	2.88	2.56	0.29		1.03
2.97	2.86	3.23	3.20	2.89	0.30		1.06
3.29	3.18	3.56	3.57	3.23	0.30		1.08
3.51	3.39	3.77	3.83	3.51	0.31		1.11
3.65	3.53	3.91	4.03	3.70	0.32		1.13
3.69	3.56	3.96	4.15	3.77	0.32		1.16
3.66	3.47	3.93	4.19	3.77	0.33		1.19
3.68	3.48	3.95	4.21	3.84	0.33		1.21
3.79	3.59	4.06	4.33	3.93	0.34		1.24
3.96	3.75	4.23	4.52	4.11	0.35		1.27
4.11	3.90	4.39	4.69	4.24	0.35		1.30
4.19	3.98	4.47	4.78	4.31	0.36		1.32
4.28	4.06	4.56	4.91	4.40	0.37		1.35
4.45	4.22	4.73	5.09	4.56	0.37		1.38
4.59	4.36	4.87	5.26	4.73	0.38		1.41
4.71	4.48	5.00	5.41	4.82	0.39		1.45
4.82	4.59	5.11	5.54	4.98	0.40		1.48
4.93	4.69	5.22	5.66	5.11	0.40		1.51
5.08	4.84	5.38	5.84	5.27	0.41		1.55
5.23	4.98	5.53	6.02	5.44	0.42		1.58
5.38	5.12	5.68	6.19	5.61	0.43		1.62
5.55	5.29	5.85	6.37	5.78	0.44		1.66
5.75	5.48	6.05	6.58	5.99	0.45		1.70
5.97	5.70	6.28	6.83	6.18	0.45		1.74
6.18	5.91	6.50	7.06	6.40	0.46		1.78
6.38	6.10	6.70	7.28	6.71	0.47		1.82
6.64	6.35	6.96	7.55	6.97	0.48		1.87
6.771632432	6.483747124	7.0948684	7.686517584	7.110414839	0.489720499	0	1.91441576

Emissions ($/ton) -Nominal $'s			($/short ton) -Nominal $'s		
SO2	NOX Annual	NOX Summer	RGGI CO_2	CO2	AEP GEN HUB - HR
0	0	0	6	0.00	10.56
0	0	0	6	0.00	10.72
0	0	0	6	0.00	10.53
0	0	0	6	0.00	10.38
0	0	0	6	0.00	9.66
0	0	0	6	0.00	9.13
0	0	0	7	0.00	8.93
0	0	0	14	13.61	11.45
0	0	0	14	14.08	11.23
0	0	0	15	14.58	11.24
0	0	0	15	15.09	10.93
0	0	0	16	15.62	10.53
0	0	0	16	16.16	10.32
0	0	0	17	16.73	10.07
0	0	0	17	17.31	10.02
0	0	0	18	17.92	10.06
0	0	0	19	18.55	9.99
0	0	0	19	19.20	10.03
0	0	0	20	19.87	10.00
0	0	0	21	20.56	10.15
0	0	0	21	21.28	10.12
0	0	0	22	22.03	10.08
0	0	0	23	22.80	10.05
0	0	0	24	23.60	10.05
0	0	0	24	24.42	10.21
0	0	0	25	25.28	10.25
0	0	0	26	26.16	10.26
0	0	0	27	27.08	10.50
0	0	0	28	28.02	10.70
0	0	0	29	29.01	10.54
0	0	0	30.02060891	30.02060891	10.80542867

Heat Rates (mmbtu/MWh)					Capacity Prices ($/MW-day) -Nominal $'s	
SPP_Central - HR	ERCOT North - HR	ERCOT South - HR	ERCOT West - HR		AEP GEN HUB Hub Cap.	SPP_Central/KSMO Cap.
9.37	0.00	0.00	0.00		113.55	25.00
9.38	0.00	0.00	0.00		87.50	25.00
9.59	0.00	0.00	0.00		100.72	25.00
9.48	0.00	0.00	0.00		151.44	25.00
8.98	0.00	0.00	0.00		180.30	25.00
8.65	0.00	0.00	0.00		209.68	25.29
8.43	0.00	0.00	0.00		213.84	36.13
10.78	0.00	0.00	0.00		218.11	48.72
10.68	0.00	0.00	0.00		222.46	63.17
10.80	0.00	0.00	0.00		226.92	79.55
10.66	0.00	0.00	0.00		231.45	97.94
10.57	0.00	0.00	0.00		236.01	118.45
10.36	0.00	0.00	0.00		240.61	141.22
10.27	0.00	0.00	0.00		245.28	166.31
10.30	0.00	0.00	0.00		249.99	193.90
10.32	0.00	0.00	0.00		254.73	224.16
10.23	0.00	0.00	0.00		259.49	257.24
10.18	0.00	0.00	0.00		264.30	264.30
10.19	0.00	0.00	0.00		269.15	269.15
10.22	0.00	0.00	0.00		273.97	273.97
10.16	0.00	0.00	0.00		278.83	278.83
10.06	0.00	0.00	0.00		283.71	283.71
10.00	0.00	0.00	0.00		288.58	288.58
9.96	0.00	0.00	0.00		293.41	293.41
10.10	0.00	0.00	0.00		298.22	298.22
10.12	0.00	0.00	0.00		303.03	303.03
10.19	0.00	0.00	0.00		307.83	307.83
10.38	0.00	0.00	0.00		312.71	312.71
10.43	0.00	0.00	0.00		317.66	317.66
10.20	0.00	0.00	0.00		322.69	322.69
10.36782872	0	0	0		327.80	327.8029342

Renewable Energy Subsidies ** ($/MWh) - Nominal $'s	Inflation Factor
11.00	2.46%
11.00	2.51%
11.00	2.43%
11.00	2.28%
12.20	2.27%
12.20	2.34%
12.20	2.39%
12.20	2.40%
12.20	2.39%
12.20	2.33%
14.70	2.26%
14.70	2.22%
13.40	2.21%
12.20	2.17%
11.00	2.18%
11.00	2.20%
9.80	2.22%
7.30	2.24%
8.60	2.24%
7.30	2.24%
7.30	2.27%
7.30	2.29%
6.10	2.30%
4.90	2.33%
2.40	2.36%
1.20	2.37%
0.00	2.42%
0.00	2.47%
0.00	2.49%
0.00	2.45%
0	0.024496074

2021H2 Nominal Base_$15CO2

	Power Prices ($/MWh) -Nominal $'s							
	PJM_AEP		SPP_Central		SPP_KSMO		ERCOT_NORTH	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2021	24.77	20.27	21.48	17.43	21.54	17.43	21.10	16.33
2022	25.98	21.02	22.84	18.26	22.98	18.33	21.87	16.99
2023	26.54	21.36	24.71	19.33	24.85	19.40	23.22	18.07
2024	27.86	22.11	25.77	19.66	25.79	19.60	25.95	18.83
2025	29.72	23.85	27.94	20.99	27.90	20.89	27.58	20.61
2026	31.12	25.48	29.91	22.49	29.77	22.34	29.77	22.13
2027	33.42	26.81	32.69	23.57	32.46	23.39	32.01	23.48
2028	44.96	35.82	43.16	32.91	43.04	32.73	40.82	31.13
2029	44.43	35.90	42.63	32.90	42.57	32.73	41.92	31.33
2030	44.13	35.85	42.68	33.47	42.57	33.29	41.55	30.68
2031	43.57	35.55	43.09	33.90	42.87	33.66	42.72	30.46
2032	43.39	35.98	43.35	34.76	43.07	34.51	43.31	29.73
2033	44.45	37.30	44.45	35.86	44.13	35.58	44.41	30.04
2034	44.93	38.40	45.12	37.22	44.80	36.93	45.17	30.14
2035	45.34	39.09	45.71	37.99	45.37	37.68	45.67	29.23
2036	46.06	39.85	46.42	38.58	46.03	38.25	46.78	29.08
2037	47.55	41.27	47.92	39.81	47.53	39.47	48.13	29.82
2038	49.45	42.70	49.71	40.95	49.28	40.59	49.27	29.80
2039	50.10	43.60	50.43	41.83	50.00	41.47	50.43	30.21
2040	51.44	44.86	52.01	43.25	51.54	42.86	51.39	30.12
2041	52.30	45.79	52.76	44.14	52.28	43.73	52.29	30.50
2042	53.31	46.91	53.97	45.37	53.48	44.97	54.39	32.58
2043	54.95	48.39	55.49	46.71	55.00	46.28	56.64	34.76
2044	56.86	49.95	57.33	48.22	56.82	47.77	58.36	37.13
2045	58.99	51.64	59.33	50.15	58.81	49.70	60.34	39.32
2046	60.99	53.42	61.35	51.95	60.80	51.48	62.70	41.39
2047	63.29	55.39	63.44	53.79	62.87	53.30	64.71	43.51
2048	65.63	57.40	65.44	55.41	64.92	54.95	66.64	47.05
2049	68.25	59.32	68.33	57.49	67.75	56.99	68.43	50.53
2050	71.88	61.31	71.73	59.26	71.14	58.76	70.96	53.93

ERCOT_South On-Peak	ERCOT_South Off-Peak	ERCOT_West On-Peak	ERCOT_West Off-Peak
21.13	16.35	20.33	15.61
21.87	17.01	21.07	16.25
23.23	18.09	22.42	17.29
26.02	18.89	25.13	18.04
27.73	20.70	26.78	19.81
29.91	22.22	28.92	21.30
32.17	23.56	31.15	22.63
41.00	31.25	39.85	30.19
42.09	31.44	40.91	30.36
41.70	30.78	40.51	29.69
42.83	30.54	41.65	29.46
43.46	29.83	42.22	28.72
44.57	30.17	43.30	29.02
45.35	30.27	44.04	29.11
45.87	29.38	44.54	28.20
47.00	29.22	45.64	28.03
48.36	29.97	47.00	28.76
49.53	29.94	48.18	28.75
50.69	30.36	49.34	29.16
51.66	30.27	50.32	29.07
52.56	30.68	51.23	29.47
54.72	32.79	53.39	31.54
57.00	35.00	55.70	33.72
58.68	37.36	57.43	36.06
60.69	39.57	59.44	38.24
63.07	41.67	61.87	40.31
65.12	43.80	63.99	42.42
67.15	47.46	65.99	46.01
68.99	51.06	67.81	49.54
71.46	54.35	70.37	52.85

12395 Btu/lb 1.6# SO2 CAPP	12500 Btu/lb 1.6# SO2 CAPP CSX-Rail	12000 Btu/lb 1.2# SO2 CAPP Compliance	12000 Btu/lb 1.67# SO2 CAPP NYMEX
59.63	59.63	67.32	59.63
62.28	62.28	69.32	62.28
64.56	64.56	71.67	64.56
66.98	66.98	74.30	66.98
69.39	69.39	77.23	69.39
71.90	71.90	80.59	71.90
74.48	74.48	84.34	74.48
77.13	77.13	88.46	77.13
79.80	79.80	92.80	79.80
82.42	82.42	96.97	82.42
85.09	85.09	100.33	85.09
87.86	87.86	103.57	87.86
90.61	90.61	106.90	90.61
93.76	93.76	110.35	93.76
96.92	96.92	113.89	96.92
100.14	100.14	117.58	100.14
103.45	103.45	121.41	103.45
106.86	106.86	125.30	106.86
110.40	110.40	129.03	110.40
114.01	114.01	133.00	114.01
117.72	117.72	137.47	117.72
121.10	121.10	142.22	121.10
123.56	123.56	146.57	123.56
126.84	126.84	151.07	126.84
130.91	130.91	155.98	130.91
135.24	135.24	161.07	135.24
139.76	139.76	166.28	139.76
144.65	144.65	171.91	144.65
150.00	150.00	178.02	150.00
155.09	155.09	183.83	155.09

Coal ($/ton) FOB -Nominal $'s

12500 Btu/lb 6# SO2 NAPP High Sulfur	13000 Btu/lb 4# SO2 NAPP Med Sulfur	11512 Btu/lb 4.3# SO2 I-Basin	8800 Btu/lb 0.8# SO2 PRB 8800	8400 Btu/lb 0.8# SO2 PRB 8400	11700 Btu/lb 0.9# SO2 Colorado	Henry Hub
50.50	52.93	46.01	12.50	12.50	42.89	2.62
51.95	54.61	46.94	12.73	12.73	44.13	2.68
53.30	56.36	47.44	13.07	13.07	45.28	2.78
54.48	57.73	47.91	13.43	13.43	46.36	2.95
55.08	57.98	48.40	13.82	13.82	47.43	3.27
56.17	59.17	48.98	14.20	14.20	48.56	3.63
57.21	60.60	49.60	14.56	14.56	49.72	3.90
57.46	62.00	50.12	14.90	14.90	50.91	4.11
58.47	63.38	50.37	15.25	15.25	52.10	4.22
59.57	64.70	51.40	15.58	15.58	53.29	4.26
60.54	66.01	52.63	15.91	15.91	54.48	4.29
60.91	67.29	53.83	16.23	16.23	55.62	4.42
61.70	68.47	55.05	16.63	16.63	56.76	4.60
62.28	68.81	56.16	17.10	17.10	57.99	4.77
62.60	68.74	57.27	17.61	17.61	59.35	4.86
63.47	69.83	58.38	18.16	18.16	60.83	4.96
64.53	71.28	59.68	18.71	18.71	62.40	5.14
65.59	72.63	60.87	19.22	19.22	64.04	5.30
66.81	74.16	62.19	19.57	19.57	65.73	5.43
68.01	75.60	63.37	19.93	19.93	67.47	5.56
69.30	77.32	64.57	20.35	20.35	69.29	5.68
70.60	80.05	65.96	20.81	20.81	71.16	5.85
72.08	85.23	67.36	21.36	21.36	72.99	6.02
73.44	88.26	68.66	21.90	21.90	74.85	6.18
74.64	90.85	70.15	22.45	22.45	76.83	6.37
75.74	93.09	71.58	22.98	22.98	78.91	6.58
76.76	95.39	73.13	23.57	23.57	81.12	6.82
77.73	97.86	74.71	24.20	24.20	83.45	7.05
78.62	101.04	76.28	24.81	24.81	85.87	7.27
79.53	105.13	77.86	25.39	25.39	88.17	7.54

Natural Gas ($/mmbtu) -Nominal $'s						Uranium Fuel UO2 ($/mmbtu) - Nominal $'s
TCO Pool	Dominion South Point Pool	TCO Deliv	HSC	PEPL TX-OK	Swing Service Adder	
2.37	2.30	2.62	2.54	2.31	0.27	0.96
2.43	2.36	2.68	2.60	2.37	0.28	0.99
2.51	2.42	2.76	2.71	2.42	0.29	1.01
2.63	2.53	2.89	2.88	2.56	0.29	1.03
2.97	2.86	3.23	3.20	2.89	0.30	1.06
3.29	3.18	3.56	3.57	3.23	0.30	1.08
3.51	3.39	3.77	3.83	3.51	0.31	1.11
3.65	3.53	3.91	4.03	3.70	0.32	1.13
3.69	3.56	3.96	4.15	3.77	0.32	1.16
3.66	3.47	3.93	4.19	3.77	0.33	1.19
3.68	3.48	3.95	4.21	3.84	0.33	1.21
3.79	3.59	4.06	4.33	3.93	0.34	1.24
3.96	3.75	4.23	4.52	4.11	0.35	1.27
4.11	3.90	4.39	4.69	4.24	0.35	1.30
4.19	3.98	4.47	4.78	4.31	0.36	1.32
4.28	4.06	4.56	4.91	4.40	0.37	1.35
4.45	4.22	4.73	5.09	4.56	0.37	1.38
4.59	4.36	4.87	5.26	4.73	0.38	1.41
4.71	4.48	5.00	5.41	4.82	0.39	1.45
4.82	4.59	5.11	5.54	4.98	0.40	1.48
4.93	4.69	5.22	5.66	5.11	0.40	1.51
5.08	4.84	5.38	5.84	5.27	0.41	1.55
5.23	4.98	5.53	6.02	5.44	0.42	1.58
5.38	5.12	5.68	6.19	5.61	0.43	1.62
5.55	5.29	5.85	6.37	5.78	0.44	1.66
5.75	5.48	6.05	6.58	5.99	0.45	1.70
5.97	5.70	6.28	6.83	6.18	0.45	1.74
6.18	5.91	6.50	7.06	6.40	0.46	1.78
6.38	6.10	6.70	7.28	6.71	0.47	1.82
6.64	6.35	6.96	7.55	6.97	0.48	1.87

Emissions ($/ton) -Nominal $'s			($/short ton) - Nominal $'s		He
SO2	NOX Annual	NOX Summer	CO2	AEP GEN HUB - HR	SPP_Central - HR
0	0	0	0.00	10.59	9.47
0	0	0	0.00	10.82	9.79
0	0	0	0.00	10.75	10.41
0	0	0	0.00	10.74	10.25
0	0	0	0.00	10.14	9.81
0	0	0	0.00	9.55	9.36
0	0	0	0.00	9.62	9.44
0	0	0	13.61	12.46	11.82
0	0	0	14.08	12.16	11.47
0	0	0	14.58	12.20	11.47
0	0	0	15.09	11.97	11.35
0	0	0	15.62	11.57	11.16
0	0	0	16.16	11.34	10.93
0	0	0	16.73	11.01	10.72
0	0	0	17.31	10.89	10.68
0	0	0	17.92	10.84	10.62
0	0	0	18.55	10.77	10.58
0	0	0	19.20	10.85	10.59
0	0	0	19.87	10.71	10.52
0	0	0	20.56	10.74	10.51
0	0	0	21.28	10.68	10.38
0	0	0	22.03	10.55	10.28
0	0	0	22.80	10.57	10.24
0	0	0	23.60	10.63	10.26
0	0	0	24.42	10.70	10.32
0	0	0	25.28	10.68	10.28
0	0	0	26.16	10.66	10.31
0	0	0	27.08	10.67	10.27
0	0	0	28.02	10.76	10.23
0	0	0	29.01	10.90	10.33

at Rates (mmbtu/MWh)			Capacity Prices ($/MW-day) -Nominal $'s	
ERCOT North - HR	ERCOT South - HR	ERCOT West - HR	AEP GEN HUB Hub Cap.	SPP_Central/KSMO Cap.
8.35	8.37	7.87	113.55	190.71
8.45	8.46	7.97	125.77	192.53
8.62	8.62	8.28	111.53	188.17
9.09	9.11	8.92	129.96	179.99
8.68	8.73	8.43	149.25	172.69
8.38	8.42	8.24	169.55	166.50
8.38	8.42	8.35	190.91	161.42
10.17	10.22	10.31	213.29	157.49
10.15	10.19	10.48	222.46	154.76
9.96	10.00	10.46	226.92	153.27
10.20	10.22	10.70	231.45	153.10
10.04	10.08	10.54	236.01	154.37
9.87	9.90	10.36	240.61	157.28
9.67	9.71	10.15	245.28	161.85
9.58	9.63	10.07	249.99	168.26
9.56	9.60	10.11	254.73	176.68
9.47	9.52	10.03	259.49	187.22
9.38	9.43	9.98	264.30	200.00
9.33	9.38	9.97	269.15	215.14
9.30	9.35	9.93	273.97	232.76
9.25	9.30	9.90	278.83	253.10
9.32	9.38	10.02	283.71	276.32
9.43	9.49	10.17	288.58	288.58
9.44	9.50	10.20	293.41	293.41
9.49	9.54	10.25	298.22	298.22
9.55	9.61	10.31	303.03	303.03
9.48	9.55	10.27	307.83	307.83
9.46	9.53	10.24	312.71	312.71
9.42	9.50	10.20	317.66	317.66
9.41	9.48	10.19	322.69	322.69

Renewable Energy Subsidies ** ($/MWh) - Nominal $'s	Inflation Factor
11.00	2.46%
11.00	2.51%
11.00	2.43%
11.00	2.28%
12.20	2.27%
12.20	2.34%
12.20	2.39%
12.20	2.40%
12.20	2.39%
12.20	2.33%
14.70	2.26%
14.70	2.22%
13.40	2.21%
12.20	2.17%
11.00	2.18%
11.00	2.20%
9.80	2.22%
7.30	2.24%
8.60	2.24%
7.30	2.24%
7.30	2.27%
7.30	2.29%
6.10	2.30%
4.90	2.33%
2.40	2.36%
1.20	2.37%
0.00	2.42%
0.00	2.47%
0.00	2.49%
0.00	2.45%

EXHIBIT SK-5

Company Response to Sierra Club Discovery Request No. 3-5

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 3
To Appalachian Power Company

Interrogatory Sierra Club 3-05:

Regarding the Company's procurement of coal over the past three years:
(a) Please state whether the Company has faced any coal shortages at Amos or Mountaineer.
(b) Please state whether the Company made the decision to buy power from the market rather than operate Amos or Mountaineer due to the price of coal or difficulty procuring sufficient coal.

Response Sierra Club 3-05:

a. It has.
b. The Company has been purchasing energy from the PJM market since approximately September of 2021 primarily due to difficulties procuring coal. As a function of the PJM energy markets the Company is a net purchaser of energy from the PJM RTO when its generation supply resources, for any reason, are less than the Company's load.

The foregoing response is made by William K. Castle, Dir Regulatory Svcs, on behalf of Appalachian Power Company.

EXHIBIT SK-6

Company Response to Sierra Club Discovery Request No. 2-3

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 2
To Appalachian Power Company

Interrogatory Sierra Club 2-03:

Please refer to the Direct Testimony of James F. Martin, Schedule 1; please provide all underlying workpapers used to generate all Figures and Tables, in machine-readable format, with cells unlocked and formulae intact.

Response Sierra Club 2-03:

See SC 2-03 Attachments 0 through 14. In response to interrogatory's during the Company RPS filing, PUR-2021-00206, Table 31 and 32 were found to contain errors. See SC 2-03 Attachment 13 for the tables reflecting witness Martin's Schedule 1 exhibit and SC 2-03 Attachment 14 for the corrected version.

The foregoing response is made by James F. Martin, Dir Resource Planning Strategy, on behalf of Appalachian Power Company.

EXHIBIT SK-7

Company Response to Sierra Club Discovery Request No. 7-4

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production
of Documents by the SIERRA CLUB
Sierra Club Set 7
To Appalachian Power Company

Interrogatory SC 7-04:

Please refer to SC 2-03 Attachments 11 and 14:

a. Please explain why Attachment 11 uses the load from “Retail Energy” (column F of “Energy” tab) to calculate the RPS requirement.
b. Please explain why Attachment 14 uses the load from “Retail Excluding Commonwealth” (column H of “load” tab) to calculate the RPS requirement.
c. Please reconcile the differences between the two methodologies and specify which load forecast should be used to calculate the RPS requirement per the VCEA legislation.

Response SC 7-04:

a-b. During the discovery process in the 2021 VCEA RPS proceeding, the Company discovered an error in its computation of the Virginia renewable energy requirement. The targets in the original filed report were inadvertently based on the use of the Retail Excluding Commonwealth column. SC 2-03 Attachment 11 was prepared during that discovery process to provide a corrected version of Table 5 in the VCEA report. SC 2-03 Attachment 14 reflected the Company’s original incorrect calculation.

c. The Retail Energy Column (column F) should be used to determine the RPS requirement.

The foregoing response is made by James F. Martin, Dir Resource Planning Strategy, on behalf of Appalachian Power Company.

EXHIBIT SK-8

Company Response to Sierra Club Discovery Request No. 5-9

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 5
To Appalachian Power Company

Interrogatory SC 5-09:

Refer to SC 2-03 Attachment 14, tab "Appendix B (MWh)".

a. Given that the "Owned Hydro" column is constant for every year between 2022 and 2051, does APCo assume that all hydro generators will continue to operate over the course of that period?
b. If yes, does that mean that the retirement dates shown for Buck and Byllesby in Tables 8 and 9 of the RPS Plan are expected to be extended?
c. If no, please explain why hydro contribution to the RPS was assumed constant for all years.
d. See comment on cell E15. Is it safe to assume that the Summersville Hydro contract will be extended past 2027 for an additional 15 years?
e. See comment on cell R7. Confirm whether APCo intends to utilize 100% of existing hydro for RPS compliance beginning in 2026 or in 2025 (per Section 8.0 of the VCEA Plan).
f. See column AE. Explain how APCo accounted for the cost of REC deficiencies in PLEXOS.

Response SC 5-09:

a. No.
b. N/A
c. Hydro contribution to the RPS was assumed constant for all year in error.
d. Yes, the Company assumed a 15 year extension to Summersville for RPS planning purposes.
e. 2025.
f. APCo did not account for the cost of REC deficiencies in PLEXOS, those deficiencies were identified after the portfolios were produced. The Company did not rerun the model, but had it rerun the model additional REC purchases would have been added to meet the deficiencies in the short term.

The foregoing response is made by James F. Martin, Dir Resource Planning Strategy, on behalf of Appalachian Power Company.

EXHIBIT SK-9

Company Response to Sierra Club Discovery Request No. 6-10

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 6
To Appalachian Power Company

Interrogatory SC 6-10:

Please refer to the Company's response to Sierra Club Request No. 5-9:

a. Has the Company conducted an updated analysis that corrects the hydro contribution to RPS error?
b. If so, please provide all relevant analysis
c. Please refer specifically to the Company's response to Sierra Club Request No. 5-9(c), in which the Company states that, "had it rerun the model, additional REC purchases would have been added to meet the deficiencies in the short term."
    i. Please explain whether this means that the Company would have purchased bundled or unbundled RECs to meet this deficiency.
    ii. Please state whether the Company would have allowed the model to build new solar or wind generation (through utility ownership or PPA's) to meet this deficiency.

Response SC 6-10:

a. No. An updated analysis has not been prepared. This error involving Buck and Byllesby is immaterial, representing only a 74,000 MWh overstatement of the self-generated REC's annually. Over the lifetime of the period modeled after the assumed 2024 retirement out through 2050 this represents about 1% of the total Virginia REC requirement.
b. N/A
c. i. and ii. The "short-term" as it was used in that response meant the period prior to 2025. Unbundled REC's would have been the only option for the model to add prior to 2025 to fill the deficit, because wind and solar were not available to be built or purchased under PPAs until 2025. Bundled REC's were not modeled. Starting in 2025, had the model been run, it would have been able to choose the most economic option to meet the additional requirement, up to its annual or cumulative limits for each resource type each year. That could have been owned or PPA wind or owned or PPA solar, or it could have chosen to purchase REC's instead.

The foregoing response is made by James F. Martin, Dir Resource Planning Strategy, on behalf of Appalachian Power Company.

EXHIBIT SK-10

Company Response to Sierra Club Discovery Request No. 5-10

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production
of Documents by the SIERRA CLUB
Sierra Club Set 5
To Appalachian Power Company

Interrogatory SC 5-10:

In the PLEXOS model used for the RPS Study, did APCo require that a certain percentage of load be met by Company-owned or contracted resources?

a. If not, explain why not.
b. If yes, provide the Company's assumptions.

Response SC 5-10:

No. Other than the mix of owned and contracted resources which were added to meet the VCEA's renewable energy targets for the Virginia jurisdictional portion of APCo's load, there is no requirement that load be served by Company resources. PLEXOS modeling matches how PJM works for vertically integrated utilities like APCo. All of the Company's energy load is assumed to be purchased from the market, regardless of what owned or contracted resource generation is in any hour. Company-owned and contracted resources were assumed to sell 100% of their energy into the market, based on economic dispatch, regardless of what load is in any hour.

The foregoing response is made by James F. Martin, Dir Resource Planning Strategy, on behalf of Appalachian Power Company.

EXHIBIT SK-11

Company Response to Sierra Club Request No. 6-1 – Attachment 1

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00001
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 6
To Appalachian Power Company

Interrogatory SC 6-01:

Please provide the historical annual capacity factors for the past five years for the following units:

a. Amos 1–3
b. Mountaineer
c. Bluff Point
d. Camp Grove
e. Beech Ridge
f. Fowler Ridge III
g. Grand Ridge II and III
h. Depot Solar
i. Wytheville Solar
j. Leatherwood Solar

Response SC 6-01:

See SC 6-01 Attachment 1

The foregoing response is made by Christian T. Beam, President & COO - Appalachian, on behalf of Appalachian Power Company.

Unit	Year	Net Cap Ftr (NCF)
Amos 1		
	2017	57%
	2018	42%
	2019	39%
	2020	31%
	2021	50%
	*2022	49%

***Thru May 2022**

Unit	Year	Net Cap Ftr (NCF)
Amos 2		
	2017	54%
	2018	53%
	2019	43%
	2020	42%
	2021	42%
	*2022	20%

***Thru May 2022**

Unit	Year	Net Cap Ftr (NCF)
Amos 3		
	2017	52%
	2018	54%
	2019	34%
	2020	46%
	2021	48%
	*2022	23%

***Thru May 2022**

Unit	Year	Net Cap Ftr (NCF)
Mountaineer		
	2017	62%
	2018	49%
	2019	71%
	2020	46%
	2021	61%
	*2022	29%

***Thru May 2022**

Unit	Year	Cap Ftr
Bluff Point		
	2017	Not Online
	2018	35%
	2019	37%
	2020	35%
	2021	36%
	*2022	48%

***Thru May 2022**

Unit	Year	Cap Ftr
Camp Grove		
	*2017	27%
	2018	29%
	2019	32%
	2020	30%
	2021	31%
	**2022	42%

*** June thru Dec 2017**

****Thru May 2022**

Unit	Year	Cap Ftr
Beech Ridge		
	*2017	24%
	2018	32%
	2019	26%
	2020	32%
	2021	29%
	**2022	32%

*** June thru Dec 2017**

****Thru May 2022**

Unit	Year	Cap Ftr
Fowler Ridge III		
	*2017	22%
	2018	25%
	2019	28%
	2020	25%
	2021	20%
	**2022	27%

*** June thru Dec 2017**
****Thru May 2022**

Unit	Year	Cap Ftr
Grand Ridge II & III		
	*2017	25%
	2018	27%
	2019	29%
	2020	27%
	2021	26%
	**2022	30%

*** June thru Dec 2017**
****Thru May 2022**

Unit	Year	Cap Ftr
Depot Solar		

** Not online as of the date of this request

Unit	Year	Cap Ftr
Wytheville Solar		

** Not online as of the date of this request

Unit	Year	Cap Ftr
Leatherwood Solar		
	2017	Not Online
	2018	Not Online
	2019	Not Online
	2020	Not Online
	2021	Not Online
	*2022	26%

***Thru May 2022**

CERTIFICATE OF SERVICE

In accordance with the Commission's April 1, 2020 Order Requiring Electronic Service, entered in Case No. CLK-2020-0007, I certify that on July 29, 2022, I sent the foregoing by electronic mail to:

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