COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA *ex rel.*

STATE CORPORATION COMMISSION **Case No. PUR-2022-00051**

In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Code § 56-597 *et seq.*

DIRECT TESTIMONY

of

DEVI GLICK

on behalf of

THE SIERRA CLUB

September 2, 2022

Summary of the Direct Testimony of Devi Glick

In its 2022 Integrated Resource Plan (IRP), Appalachian Power Company (APCo or the Company) assumes that continued ownership of its Amos and Mountaineer coal plants (collectively, the Plants) is part of a least-cost resource plan for Virginia ratepayers relative to retirement (or removal from the Virginia rate base) and replacement with alternatives. APCo based this assumption on analysis conducted for its 2021 Renewable Portfolio Standards Plan (Case No. PUR-2021-00206) and supplemented by a spreadsheet analysis in support of updates to its E-RAC Rider (Case No. PUR-2022-00001).

The analyses that the Company has submitted to support the continued operation of both Plants have all been flawed. The analysis the Company submitted in the E-RAC docket in support of investments in Effluent Limitation Guidelines (ELG) compliance was overly simplistic and overstated Virginia's replacement resource needs. Furthermore, the Company's IRP did not model compliance with the West Virginia mandated 69-percent capacity factor for the plants. Moreover, the recent passage of the Inflation Reduction Act (IRA), materially changed resource cost trajectories and rendered the Company's modeling assumptions and findings obsolete. For these reasons, I find that the Company's IRP modeling was insufficient to support its proposed Hybrid Plan.

To determine whether continued ownership of the Plants is part of a reasonable, least-cost resource plan for Virginia ratepayers, I performed independent modeling that corrects the Company's modeling errors and updates resource costs to account for the IRA. The modeling then examines four scenarios and one sensitivity:

(1) **West Virginia Public Service Commission (PSC) Preferred** includes the ELG investments at both Plants and assumes they 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 coal required to sustain those operations.

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

(3) **Synapse Full Coal Removal** assumes the removal of both Plants from the Virginia rate base on December 31, 2028 and replacement with alternatives. This portfolio is optimized around updated IRA cost assumptions and relies on APCo's pre-IRA market forecasts.

(4) **Synapse Partial Coal Removal** assumes removal and replacement of Amos from the Virginia rate base on December 31, 2028. This portfolio is also optimized around the updated IRA cost assumptions and relies on APCo's pre-IRA market forecasts.

My independent modeling finds that removing either Amos or both Amos and Mountaineer from the Virginia rate base beginning in 2029 will result in a net present value of savings of between $169 and $264 million through 2040 for Virginia ratepayers. I therefore recommend that the Commission reject APCo's IRP and require it to file an updated IRP that incorporates the impact of the IRA on renewable costs and energy market prices, models Amos and Mountaineer operating at the West Virginia Commission-ordered 69-percent capacity factor and reflects the Commission's ruling in the pending E-RAC case.

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Devi Glick and I am a Senior Principal 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 analyze and publish on a variety of issues related to electric utilities, including power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than ten years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Glick Direct Exhibit 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. Yes. I submitted testimony in Case Nos. PUR-2022-00006 and PUR-2018-00195.

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

A. My testimony evaluates Appalachian Power Company's (APCo or the Company) 2022 Integrated Resource Plan (IRP). I reviewed the Company's modeling assumptions around the Amos and Mountaineer power plants (collectively, the Plants) in this docket as well as the recent Effluent Limitations Guidelines (ELG) docket (PUR-2022-00001) and APCo's consideration of replacement resources in both contexts. I also evaluated whether the Company adequately considered the impact of a 69-percent annual capacity factor mandate imposed by the West Virginia Public Service Commission (PSC or West Virginia Commission) in Case No. 21-0339-E-ENEC and the potential denial of ELG cost recovery in its modeling analysis. I further evaluated how the passage of the Inflation Reduction Act[1] (IRA) changes the economics of continuing to operate Amos and Mountaineer. I quantified 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-percent capacity factor through 2040. This assumption reflects the West Virginia PSC's September 2, 2021, Order mandating that "[t]he capacity factor for [Amos and Mountaineer] should be 69 percent" in fuel-cost recovery dockets, with the potential for an even higher capacity factor.[2] APCo states that the West Virginia Commission Order from Case No. 20-1040-E-CN, which granted the Company approval to invest in both Coal Combustion Residuals

1 Inflation Reduction Act of 2022, Public Law No. 117-169 (August 16, 2022).

2 *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. As detailed further below, the 69-percent capacity factor mandate was reinforced in a subsequent order dated May 13, 2022.

(CCR) and ELG compliance, is the basis of its assumption that the Amos and Mountaineer units will operate through 2040.[3]

1b) West Virginia PSC Preferred, high coal price sensitivity mirrors scenario 1a, except that I apply a higher price of coal to reflect challenges the Company could face in procuring the coal required to sustain operations at 69 percent.

2) APCo Preferred includes the ELG investments at APCo's four existing coal-fired units at Amos and Mountaineer and assumes that APCo operates those 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 instead meets Virginia's system needs with a combination of solar PV, wind, battery storage, and market purchases. This portfolio is optimized around the updated IRA cost assumptions.

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-percent capacity factor through 2040. This portfolio is optimized around the updated IRA cost assumptions.

3 IRP Report at 85.

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 in this present IRP docket. I also rely on public information and analysis from the ELG docket, which formed the basis of the Company's assumption that the Plants will continue to operate through 2040. In addition, I 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 Description
DG-1	Resume of Devi Glick
DG-2	Company Response to Environmental Respondent Discovery Request No. 4-01
DG-3	Company Response to Staff Discovery Request No. 9-81
DG-4	Company Response to Sierra Club Discovery Request No. 1-06
DG-5	Company Response to Sierra-Club Discovery Request No. 3-05
DG-6	Company Response to Sierra Club Request No. 6-04 (Case No. PUR-2022-00001)
DG-7	Company Response to Staff Discovery Request No. 7-70 – Attachment 1
DG-8	Company Response to Sierra Club Discovery Request No. 1-15
DG-9	Company Response to Sierra Club Discovery Request No. 1-07
DG-10	Company Response to Sierra Club Request No. 2-03 (Case No. PUR-2022-00001)

DG-11	Company Response to Sierra Club Request No. 7-04 (Case No. PUR-2022-00001)
DG-12	Company Response to Sierra Club Request No. 2-03, Attachment 6 (Case No. PUR-2022-00001)
DG-13	Company Response to Sierra Club Request No. 5-09 (Case No. PUR-2022-00001)
DG-14	Company Response to Sierra Club Discovery Request No. 5-10 (Case No. PUR-2022-00001)
DG-15	Company Response to Sierra Club Request No. 3-04 – Attachment 1

II. OVERVIEW OF TESTIMONY AND CONCLUSIONS

Q. Please summarize your primary findings.

A. First, I find that the Company's IRP modeling was insufficient to support APCo's proposed Hybrid Plan. Specifically, the Company did not model the removal of Amos or Mountaineer from the Virginia rate base, which could happen if ELG cost recovery is denied. Nor did it model the impacts of the West Virginia Commission's 69-percent capacity factor mandate on the Plants' economics.

Second, I find that the Company's Retirement Analysis is insufficient and does not provide value to the Commission. Specifically, APCo failed to capture the potential to avoid ELG expenses since the Company included 100 percent of environmental upgrade costs in its modeling and fixed the retirement date for a single unit at a time rather than identifying the most economic retirement date for the portfolio.

Third, I find that the IRA further improves the economics of removing Amos and Mountaineer from the Virginia rate-base; thus, the Company should update all of its modeling with new renewable cost assumptions and market price forecasts that reflect the impact of the new and extended tax credits for renewable resources.

Fourth, my independent modeling demonstrates that it is uneconomic, and not in the best interest of Virginia ratepayers, for APCo to plan its future resource mix around the assumption that the Commission approves ELG cost recovery at Amos and Mountaineer and continues to operate the Plants through 2040. According to my modeling, removing Amos from the Virginia rate base beginning in 2029 will result in a net present value (NPV) of savings of at least $264 million through 2040. The modeling further indicates that removing both Amos and Mountaineer from the Virginia rate base will result in NPV savings of at least $169 million, as shown in Table 3.

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 (NPVRR) 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)	$5,339	$5,167	$5,170	$5,075
Solar (MW)	2,929	2,929	2,334	1,205
Wind (MW)	855	855	2,389	2,178
Battery Storage (MW)	625	625	391	377
Gas (MW)	512	512	512	512
Coal (MW)	2,295	2,295	167	823
Net Capacity Exchange (MW)	-1,639	-1,639	509	241

Q. Please summarize your primary recommendations.

A. Based on my analytical findings above and as described in further detail in this testimony, I recommend that the Commission reject APCo's IRP and Retirement Analysis, and require the Company's modeling to include:

- a scenario that reflects the Commission's ruling in Case No. PUR-2022-00001;
- a scenario where Amos and Mountaineer must operate at a 69-percent capacity factor per the West Virginia Commission Order in Case No. 21-0339-E-ENEC;
- updated renewable cost assumptions for solar PV, wind, and battery storage that are consistent with the tax credits included in the IRA; and

- updated market energy prices that reflect the impact of lower cost renewables costs on the PJM energy market.

III. SUMMARY OF IRP AND RETIREMENT ANALYSIS

Q. What did APCo model in its IRP and Retirement Analysis?

A. APCo modeled ten different scenarios for the IRP, and nine additional scenarios for the Retirement Analysis. As part of an agreement with Commission Staff, the Company supplemented its original analysis and provided 16 additional unit retirement scenarios through discovery. The analysis period for all scenarios spans 15 years between 2022 and 2036. In the IRP modeling, the Company assumed the continued operation and ongoing investment in Amos and Mountaineer[4] based on the West Virginia Order in Case No. 20-1040-E-CN. APCo's IRP analysis assumed these coal plants will operate economically through 2040, which does not adhere to the West Virginia Commission's Order to run both Plants at a 69-percent capacity factor.[5]

Q. What were the results of APCo's IRP modeling exercise?

A. APCo presented a Hybrid Plan derived from the IRP Base Portfolio, which is itself consistent with the Company's 2021 Virginia Clean Economy Act (VCEA) Renewable Portfolio Standards (RPS) Plan. The Hybrid Plan includes a similar mix of supply-side resources as the Base Portfolio and allows for an earlier addition of wind to take advantage

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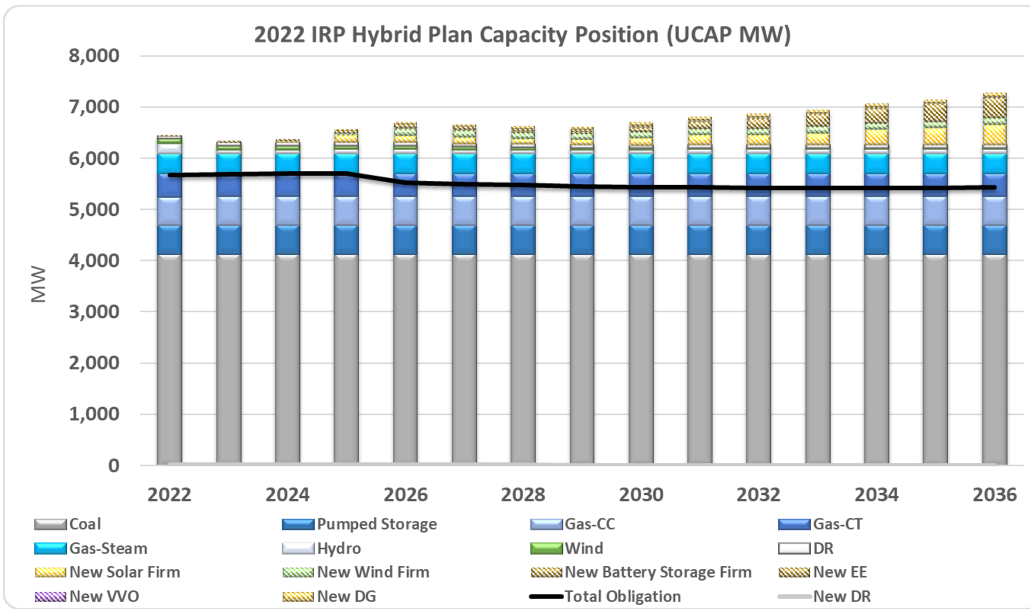
4 IRP Report at ES-1, 85.

5 Company Response to Environmental Respondent Discovery Request No. 4-01, attached as Exhibit DG-2.

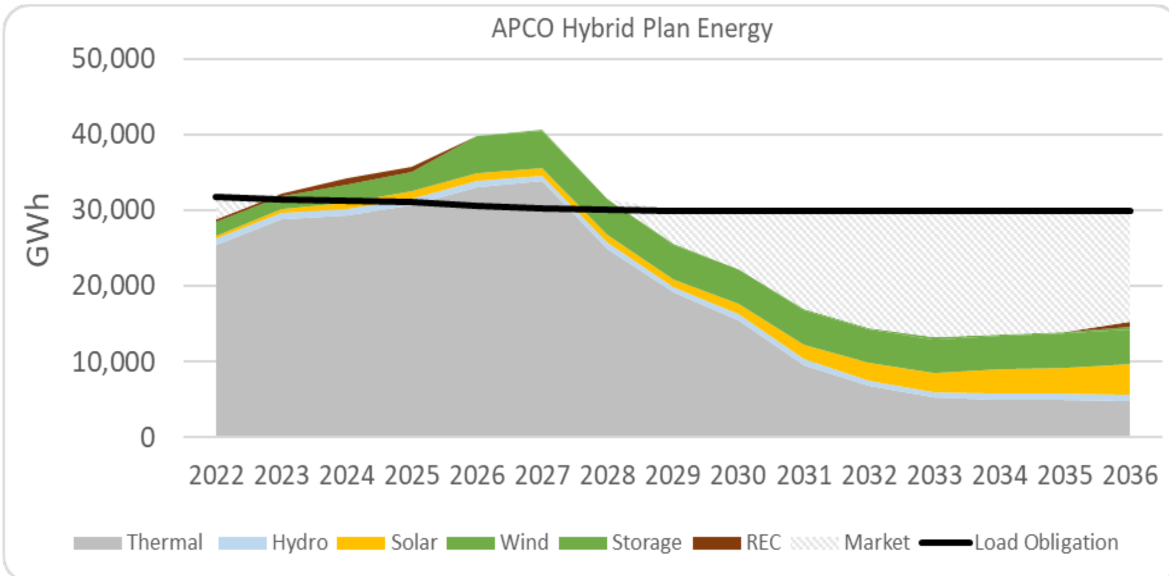
of the Production Tax Credits scheduled to phase out in December 2025 under prior law. The Hybrid Plan also adds more uniform storage resources across the analysis while maintaining constant coal capacity across the analysis period, as shown in Figure 1.[6] Coal generation is high and grows between 2022 and 2027, before it rapidly declines between 2028 and 2036, as shown in Figure 2.

Figure 1: APCo's Hybrid Plan Capacity Position (As Presented in Figure ES-3 of the IRP)



6 IRP Report at ES-4.

Figure 2: APCo's Hybrid Plan Generation Mix
(As Presented in Figure ES-4 of the IRP Report)



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

A. Yes. First, except for in the retirement analysis that the Commission ordered APCo to complete in approving the Company's stipulation with the Sierra Club, APCo locked in the retirement of Amos and Mountaineer in 2040. Second, APCo did not consider the impact that uneconomic coal generation could have on energy costs or revenues in its IRP modeling. Given the West Virginia PSC 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. Finally, the results are now outdated as the modeling does not include the tax credits provided in the IRA and relies on a Fundamentals Forecast (including market prices) that was created over a year ago.

Q. What were the results of APCo's Retirement Analysis?

A. APCo found that maintaining ownership of the Plants through 2040 was less expensive than retiring any of the units in 2028 or 2034 by a range of $25 million to $547 million.[7]

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

A. Yes. First, APCo's interpretation of the requirement to do a unit-by-unit analysis was narrow and limited. Rather than testing and identifying an economic retirement date for each individual unit at Amos and Mountaineer, APCo hard-coded in the retirement dates for every unit except one in each portfolio and evaluated the resulting costs. The requirement in the settlement agreement to do a unit-by-unit analysis did not mean that APCo should only evaluate a single unit a time, but rather that the Company should evaluate the economics of each individual unit in its analysis. It is disappointing that the Company chose such a narrow interpretation, as the results are only marginally useful. The Company did eventually conduct additional analysis to look at the retirement of multiple units at once, but only once requested by Staff.

Second, the Company did not consider the impact of uneconomic coal generation in its analysis, which is critical because the West Virginia PSC ordered that the units be operated at a 69-percent capacity factor regardless of economics.

Third, the analysis is outdated because it does not include the impacts of the IRA in renewable costs and energy market prices.

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7 IRP Report at 87.

Finally, the Company included 100 percent of the ELG costs in all scenarios, even in the retirement portfolios and all staff portfolios, indicating that it believes these costs are unavoidable even if the units retire.[8] This assumption is unsupported and makes the retirement scenarios look costlier than they should be. To be a useful Retirement Analysis, the Company's Retirement Analysis should not have included ELG costs in scenarios where units retire in 2028.

Given that the Commission has not yet approved the ELG costs at Amos and Mountaineer, it is crucial for the Commission to evaluate whether rejecting ELG cost recovery and avoiding new capital expenditures would be more beneficial than continued operation. Because the Retirement Analysis includes 100 percent of ELG costs in the modeling and does not account for the potential to avoid these expenses, the results are not useful.

Q. What does the Company intend to do given the results of its IRP and Retirement Analysis?

A. The Company stated that the IRP is not a commitment to specific resource additions or extensions or other courses of actions. Rather, the Company used the IRP exercise to develop a five-year action plan. APCo stated in its Action Plan that it intends to monitor federal and state regulatory developments related to continued operation of the Amos and Mountaineer plants[9] and adjust its action plan to reflect changing circumstances.[10]

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8 Company Response to Staff Interrogatory Request No. 9-81, attached as Exhibit DG-3.

9 IRP Report at ES-6.

Given developments since the Company completed its IRP modeling and Retirement Analysis, APCo should follow its own action plan and present an updated analysis that reflects: (1) operation of the Amos and Mountaineer units at a 69-percent capacity factor; (2) the Commission's potential denial of ELG cost recovery; and (3) updated renewable costs and market prices that account for the tax credits included in the IRA.

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

A. Yes. I used an industry-standard capacity expansion and production cost model called EnCompass 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 one or both Plants were removed from the Virginia rate base. I relied primarily on APCo's own input values, with a few adjustments to capacity market prices and renewable costs to account for new tax credit legislation included in the IRA. 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.

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10 *Id.*

IV. 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 scenarios and one fuel price sensitivity. All scenarios utilized updated renewable and storage prices that reflected the new and extended tax credits included in the IRA.

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

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

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

3) **Synapse Full Coal Removal** removes all four units from the Virginia rate base on December 31, 2028. This portfolio is optimized around the updated IRA cost assumptions.

4) **Synapse Partial Coal Removal** removes the Amos plant from the Virginia rate base on December 31, 2028, includes ELG investments at Mountaineer, and operates that unit at an annual 69-percent capacity factor through 2040. This portfolio is optimized around the updated IRA cost assumptions.

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

A. I designed Scenario 1 to mirror the Company's modeling presented in its 2021 RPS Plan, which was provided in Schedule 1 of Martin's testimony in Case No. PUR-2022-0001, and then I modified the generation assumptions for Amos and Mountaineer to reflect a 69-percent annual capacity factor across the analysis period in accordance with the West Virginia PSC 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 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.[11]

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11 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 for this difference. Namely, I presumed that the gas combined cycle unit that the Company

Scenario 1b was identical to Scenario 1a, except that I tested a higher coal price sensitivity for Amos and Mountaineer 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-percent capacity factor at the current price.[12]

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 PSC Order to operate the units at a 69-percent capacity factor.

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 removal of the Plants from Virginia's 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 while optimizing to account for the tax credits included in the IRA. I limited the Company's ability to export in the first stage of this scenario to prevent the model from over-building for the sole purpose of exporting based on the price differential between renewables and market prices. This step was necessary

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.

12 Company's Response to Sierra Club Request No. 1-06, attached as Exhibit DG-4.

because we had to rely on APCo's existing market prices, which do not take into account the impact of the IRA.

The resulting builds and imports represent the optimal resource plan for APCo's Virginia ratepayers if both Plants were to be allocated fully to West Virginia and removed from Virginia 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 model was allowed to export freely. The final results represent a future in which West Virginia customers take on 100 percent ownership of both Plants in 2029 and run them at a 69-percent capacity factor, while Virginia customers meet their energy and capacity needs with alternative resources.

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 percent starting in 2029.

Q. Why did you align your modeling with the 2021 VCEA RPS Plan scenarios rather than the 2022 IRP?

A. APCo did not address the removal of Amos or Mountaineer as part of its modeling in its 2022 IRP. Although the Company conducted a retirement study to satisfy a stipulation agreement with Sierra Club and then at the request of Staff, APCo otherwise assumed that the units would stay online through 2040 based on West Virginia's approval of the

ELG and CCR investments at both Plants in Case No. 20-1040-E-CN.[13] The Company's most recent analysis of the cost of keeping the Plants online relative to retirement was in the ELG docket (Case No. PUR-2022-0001). Therefore, I used the ELG analysis as the baseline for evaluating whether the Company has justified its decision to keep the Plants online through 2040.

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

A. Largely, yes, but with a critical difference for capacity market price and renewable tax credit assumptions, as I will explain later in this 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/storage projects, I did not use a single levelized cost of energy (LCOE) for a hybrid 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.[14]

Table 2 below shows sources for key input assumptions in the Synapse modeling

13 2020 IRP Report at 85.

14 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 2. Synapse Modeling Input Assumptions

Input	Source(s)
Load Forecast	SC 2-1 (E-RAC SC 2-02), Confidential Attachment 1
Load Shape	SC 2-19, Attachment 1 in Case No. PUR-2022-00001
Reserve Margin	14.9%, per Direct Testimony of Martin at 16:10 in Case No. PUR-2022-00001
Coal Prices	SC 4-01 Attachment 2 in Case No. PUR-2022-00001, SC 2-4 (E-RAC SC 3-01) Confidential Attachment 1, SC 2-6 (E-RAC 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 in Case No. PUR-2022-00001, SC 2-7 (E-RAC SC 5-02) ES Attachment 1
RGGI Prices	SC 2-21 Attachment 1 in Case No. PUR-2022-00001
Market Energy Prices	SC 4-01, Attachment 1. AP Market Purchase Prices EIA_RGGI-VCEA.csv in Case No. PUR-2022-00001
Onshore Wind Costs	SC 2-3 (E-RAC SC 2-47) Confidential Attachment 1
Solar Costs	SC 2-3 (E-RAC SC 2-47) Confidential Attachment 2
Battery Costs	Martin Schedule 1 in Case No. PUR-2022-00001, Appendix D
Paired Battery Costs	Martin Schedule 1 in Case No. PUR-2022-00001, Appendix D with NREL ATB adjustments
Heat Rates	SC 2-5 (E-RAC SC 4-06) Confidential Attachment 1
RPS Requirement	SC 2-03 in Case No. PUR-2022-00001, Attachment 11
ELCC Values	SC 2-3 Attachment 3 in Case No. PUR-2022-00001, SC 4-3 Attachment 1 in Case No. PUR-2022-00001
Renewable Capacity Factors	SC 2-20 Attachments 1 and 2 in Case No. PUR-2022-00001
Avoidable Amos & Mountaineer Capital Costs	Martin E-RAC Case 1 workpaper 2-7 Final.xlsx in Case No. PUR-2022-00001
WACC	6.842% per APCo Response to Sierra Club Request No. 2-44 in Case No. PUR-2022-00001
Amos & Mountaineer Capacity Factors	SC 2-2 (E-RAC SC 2-27) CONFIDENTIAL Attachment 1

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

Q. How is the analysis you present here different from the analysis Sierra Club presented in Case No. PUR-2022-00001?

A. I updated several assumptions from the Synapse analysis that Sierra Club presented in Case No. PUR-2022-00001, but my analysis relies on largely the same inputs. My updates included incorporating renewable cost updates to reflect the IRA and correcting APCo's modeling error that resulted in its portfolios not actually complying with the VCEA. I also updated my paired storage cost assumptions to include financing and fixed O&M inputs that were inadvertently excluded.

Q. Explain why it was important to update resource costs to reflect the impact of the IRA.

A. The IRA is expected to lower costs for solar PV, wind, and battery storage. With updated renewable costs, I expect (1) the cost of the Company's existing portfolio relative to the coal removal scenarios will increase, and (2) the model will make different optimization decisions than it would with pre-IRA costs assumptions and develop a different and lower cost clean energy portfolio than with the pre-IRA costs.

Q. Explain how you incorporated the Inflation Reduction Act into your modeling.

A. For all technology types eligible for the Investment Tax Credit or Production Tax Credit, I assumed the resources constructed or procured by the Company will meet the prevailing wage and apprenticeship requirements necessary to receive the alternative rate put forth in the IRA.

For storage, I applied a 30-percent investment tax credit assumption through 2032 and followed the phase-out trajectory outlined in the IRA for the following years. These credits were normalized over the book life of the project.

For solar and wind, I modified the Company-provided LCOE workbooks to make them consistent with the IRA provisions. I applied a $26/MWh production tax credit through 2032 and followed the phase-out trajectory for the following years. These credits are available for the first 10 years of the project.

Q. Are there any other significant changes you expect to see from the IRA that will impact the results of your and the Company's analyses?

A. Yes, the IRA is expected to drive down energy market prices as more zero marginal cost resources are deployed on the grid. This means that the Amos and Mountaineer plants are likely to become even more uneconomic to operate and will earn less revenue in the market than APCo currently projects. Unfortunately, this is not something that our current analysis reflects. As the IRA passed only recently, we do not yet have updated energy market prices from APCo that reflect the law's projected impacts.

Q. Has the Company completed any modeling that reflects the impacts of this new law?

A. No, but given the substantial impact of the IRA, I strongly recommend that the Company update all its IRP modeling.[15] While it is true that there will always be changes in policy and market factors during any case, the IRA is among the most consequential changes to

15 Company Response to Sierra Club Request No. 3-05, attached as Exhibit DG-5.

resource cost assumptions in recent years. It will have dramatic impacts on resource planning modeling and decision making, as demonstrated by my modeling results.

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. As discussed below, the zone in which APCo serves load has historically seen the lowest capacity prices in the market. There have also been significant structural changes to the PJM capacity market of late.

The PJM market capacity price forecast that the Company provided was created in July 2021 and had not been updated to reflect any of the changes to the PJM capacity market since that date.[16] 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.[17] 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.[18] APCo's use of this July 2021 forecast was also questioned by Staff in Case No. PUR-2022-00001.[19]

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16 Company Response to Sierra Club Request No. 6-04 in Case No. PUR-2022-00001, attached as Exhibit DG-6.

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

18 Company Response to Staff Request No. 7-70 Attachment 1.xlsx, attached as Exhibit DG-7.

19 *See Petition of Appalachian Power Company for Approval of Rate Adjustment Clause E-RAC etc.*, Case No. PUR-2022-00001, Pre-Filed Testimony of Timothy A. Morris at 11:13–11:19 (August 23, 2022), available at https://bit.ly/3elF8TX.

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.[20] Since July 2021, PJM has adopted numerous changes that were incorporated in the 2023/2024 Base Residual Auction. This includes the Minimum Offer Price Rule (MOPR), the Market Seller Offer Cap (MSOC), and Effective Load Carrying Capability (ELCC) updates.[21] 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. I therefore 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

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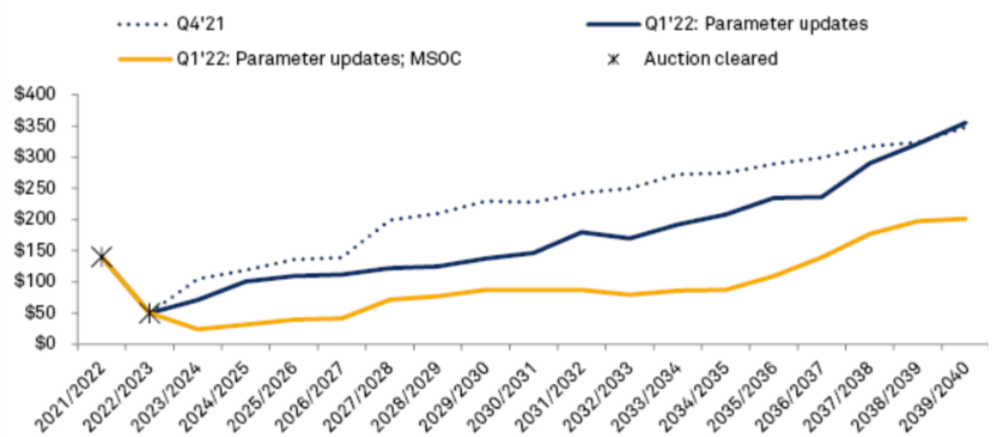
20 Company Response to Sierra Club Request No. 1-15, attached as Exhibit DG-8.

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

MSOC to inform the long-term price projection (the yellow line in Figure 3 below).[22] According to S&P:

> Lower 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.[23]

Figure 3. PJM RTO Capacity Price Forecasts ($ / MW-Day)



Note: Forecasts shown for Q4 2021 and Q1 2022 with varying assumptions.

I also acknowledge that there is 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

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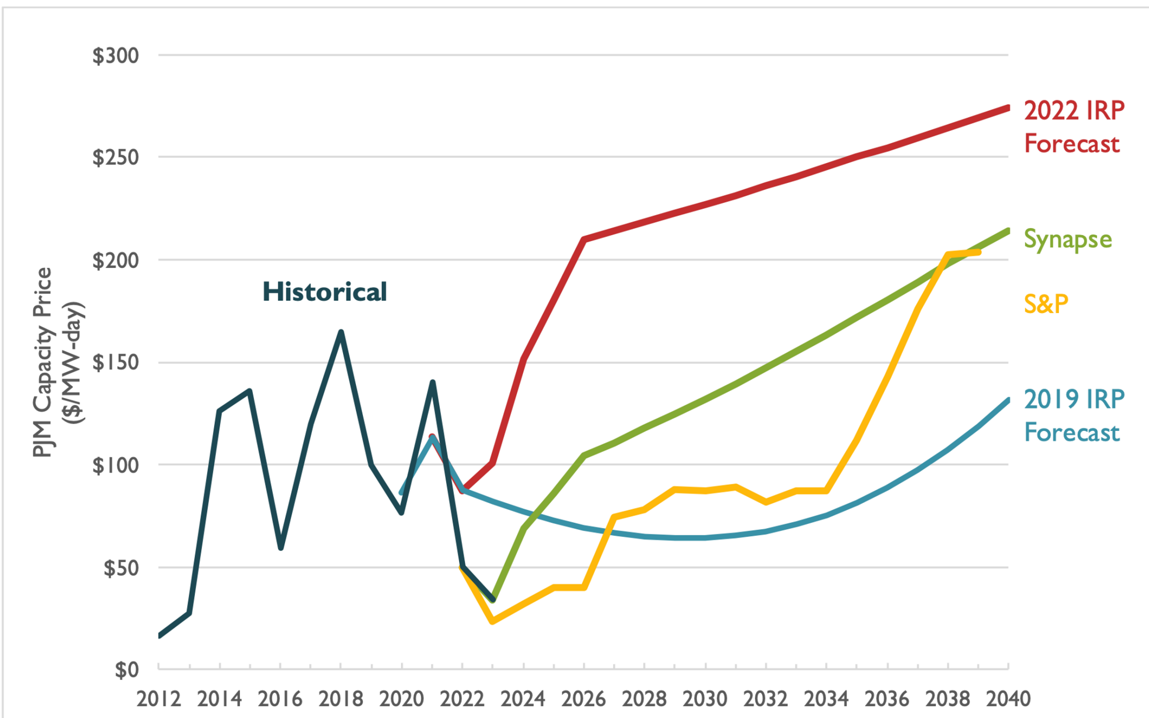
22 Katherine McCaffrey, *PJM Capacity Prices Projected to Drop Due to Auction Parameter, Market Updates*, S&P Global Market Intelligence (May 2022), available at https://bit.ly/3zozWWf.

23 *Id.*

may be an aggressive implementation of the MSOC and prices may clear higher.[24]

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 far more up-to-date and representative of current market conditions than the forecast 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 4 below.

Figure 4. PJM Capacity Price Forecast by Source (Nominal $ / MW-Day)[25]



24 *Id.*

25 The 2019 IRP Forecast prices are included in a non-confidential portion of the Company Response to Environmental Respondent Discovery Request No. 5-2 Attachment 1 and are also graphed in public Figure 26 of the 2019 IRP itself. The 2022 IRP Forecast prices are provided in Exhibit DG-7.

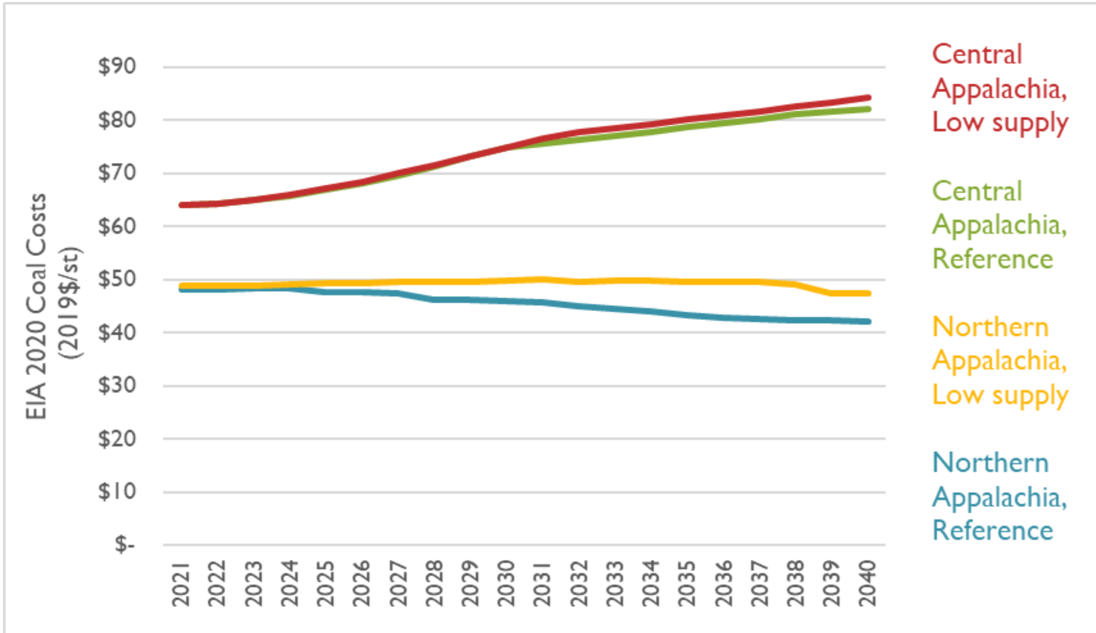
Q. Explain how APCo's capacity price forecast has changed since its last IRP.

A. APCo significantly increased its capacity price forecast between the 2019 IRP and the 2022 IRP. This high capacity price forecast that the Company is using for the 2022 IRP is the same as the one it used in the VCEA RPS Plan and Case No. PUR-2022-00001. While capacity prices have varied over the past decade, there is no precedent for expecting a jump as dramatic as what APCo is projecting.

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 U.S. Energy Information Administration's 2020 Annual Energy Outlook (EIA AEO), as this was the source the Company used on in its original forecast. I show these prices in Figure 5 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 5. 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.[26] The Company has also stated that it is not able to procure from its current suppliers the 10 million tons of coal that would be required to operate Amos and Mountaineer at a 69-percent capacity factor.[27] This suggests that the Company may have to pay more to secure enough coal in the future.

26 Company Response to Sierra Club Request No. 1-07, attached as Exhibit DG-9.

27 Exhibit DG-4.

V. SYNAPSE MODELING RESULTS

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

A. As shown in Table 3 below, the Synapse optimized modeling found that removing Amos from the rate base in Virginia would result in cost savings to Virginia customers of $264 million and removing both Plants would result in cost savings of $169 million relative to Scenario 1, the West Virginia PSC Preferred Case. These results differ from what APCo found in its retirement analysis due to the difference in capacity prices, renewable tax credits, and avoidable ELG costs included in the Synapse modeling.

Table 3. NPVRR for the Virginia Jurisdiction by Scenario

Scenario	Revenue Requirement for APCo's Virginia Ratepayers		
	NPVRR ($Millions)	Delta from West Virginia PSC Preferred ($Millions)	Delta from APCo Preferred ($Millions)
1a. West Virginia PSC Preferred	$5,339	N/A	$173
1b. West Virginia PSC Preferred, High Coal	$5,513	$174	$346
2. APCo Preferred	$5,167	-$173	N/A
3. Full Coal Removal	$5,170	-$169	$3
4. Partial Coal Removal	$5,075	-$264	-$91

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 ratepayers relative to the West Virginia PSC Preferred Case (see Table 4).

Table 4. NPVRR Results for Scenarios Using APCo's Capacity Price

Scenario	Revenue Requirement for APCo's Virginia Ratepayers Under Higher Capacity Price Forecast		
	NPVRR ($Millions)	Delta from West Virginia PSC Preferred ($Millions)	Delta from APCo Preferred ($Millions)
1a. West Virginia PSC Preferred	$5,181	N/A	$173
1b. West Virginia PSC Preferred, High Coal	$5,355	$174	$346
2. APCo Preferred	$5,009	-$173	N/A
3. Full Coal Removal	$5,298	$116	$289
4. Partial Coal Removal	$5,095	-$86	$86

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

A. Yes, they are now. But the portfolio in APCo's original RPS Plan Scenarios was not. 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 it provided an updated version that showed a projected REC shortfall in many years.[28] Because the Company's RPS Plan was actually *not* VCEA-compliant—and because Synapse Scenarios 1 and 2 relied solely on the Portfolio 1 resource builds from the RPS Plan—I had to add in the cost of purchasing renewable energy credits (RECs) to make them VCEA-compliant.

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

A. Yes, Synapse Scenarios 3 and 4 are VCEA-compliant. The model was not allowed to add new resources until 2025 and has the same generation portfolio as Scenarios 1 and 2 until that year. Prior to 2025, I added the cost of purchasing RECs to ensure VCEA compliance. 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 2025 onwards.

Q. How did you account for the Company's REC shortfall in the scenarios you modeled?

A. As mentioned above, I assumed that the Company would purchase RECs to meet the shortfall observed in all scenarios.[29] In discovery, the Company stated that it had not

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28 Company Response to Sierra Club Discovery Request No. 2-03 Attachment 6 in Case No. PUR-2022-00001, attached as Exhibit DG-10; SC 2-03 Attachment 14.xlsx. This workbook contains voluminous spreadsheet data in numerous tabs and can be produced upon request. It is also known to contain errors, as identified in the Company's Response to Sierra Club Discovery Request No. 7-04 in Case No. PUR-2022-00001, attached as Exhibit DG-11.

29 Exhibit DG-12.

accounted for the cost of REC deficiencies in PLEXOS, as these were identified after the portfolios had been produced. APCo also stated that it would have added REC purchases to meet the deficiencies if it were to re-run the model.[30]

Q. Why do customers save money in the scenarios where the Commission does not approve the ELG upgrades at Amos and Mountaineer compared with the scenarios in which the units 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 to 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 5 and would add to both Plants' existing undepreciated balances. 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 Fuel costs at the Amos and Mountaineer plants are also likely to be highly uncertain given APCo's acknowledgement that it is unsure if, and at what price, it can procure enough coal to operate the units at the West Virginia PSC-ordered 69-percent capacity factor.

30 Company Response to Sierra Club Request No. 5-09 in Case No. PUR-2022-00001, attached as Exhibit DG-13.

Table 5. 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 from Case No. PUR-2022-00001. This document contains voluminous spreadsheet data in numerous tabs and can be produced upon request.

Q. What types and quantities of resources did your modeling add 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's system has excess firm capacity that it can sell, which I represent as negative numbers in Table 6 below.

Table 6. 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 Paired Battery	New Battery Storage	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	(1,073)
2037	350	400	900	900	-	-	400	(1,155)
2038	350	400	900	1,200	-	-	400	(1,235)
2039	350	400	900	1,200	219	73	400	(1,368)
2040	350	400	900	1,200	669	223	400	(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 power purchase agreement (PPA) solar, Company-owned and PPA wind, hybrid solar/storage systems, and standalone storage. I constrained the amount of annual and cumulative builds for each resource based on the limits that APCo provided. This is why the model only builds a limited about of each resource type in each year (especially PPA resources). It also relies on firm capacity purchases from PJM (shown as positive numbers in Table 7 below). In some years, the Company has excess firm capacity that it can sell, which I represent as negative numbers below. Because the full and partial removal coal scenarios were optimized around lower capacity prices than APCo used, the model builds less battery storage and imports more firm capacity after 2033 than we see in APCo's scenarios. These results indicate that the Company has a firm capacity need in this timeframe, and will meet them through battery storage, imports, or whatever resource is the lowest cost option at this time.

Table 7. Full Coal Removal Scenario Cumulative New Capacity Builds (MW), Virginia Jurisdiction

Year	New PPA Wind	New Utility Wind	New PPA Solar	New Utility Solar	New Paired Solar	New Paired Battery	New Battery Storage	Capacity Market
2022	-	-	-	-	-	-	-	(75)
2023	-	-	-	-	-	-	-	(66)
2024	-	-	-	-	-	-	-	(72)
2025	30	-	-	-	45	15	10	(418)
2026	180	-	-	-	45	15	10	(319)
2027	320	-	-	-	45	15	10	(347)
2028	350	140	-	-	90	30	10	(394)
2029	350	280	10	-	135	45	10	1,511
2030	350	880	310	600	180	60	90	1,102
2031	350	1,350	610	600	225	75	90	992
2032	350	1,350	900	600	270	90	90	887
2033	350	1,930	900	600	315	105	265	642
2034	350	1,930	900	870	360	120	265	544
2035	350	1,930	900	870	405	135	265	517
2036	350	1,930	900	870	405	135	265	524
2037	350	1,930	900	870	405	135	265	520
2038	350	1,930	900	870	405	135	265	518
2039	350	1,930	900	870	405	135	265	511
2040	350	1,930	900	870	405	135	255	509

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 less than in Scenario 3. The main difference is fewer megawatts of utility solar and 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 8 below.

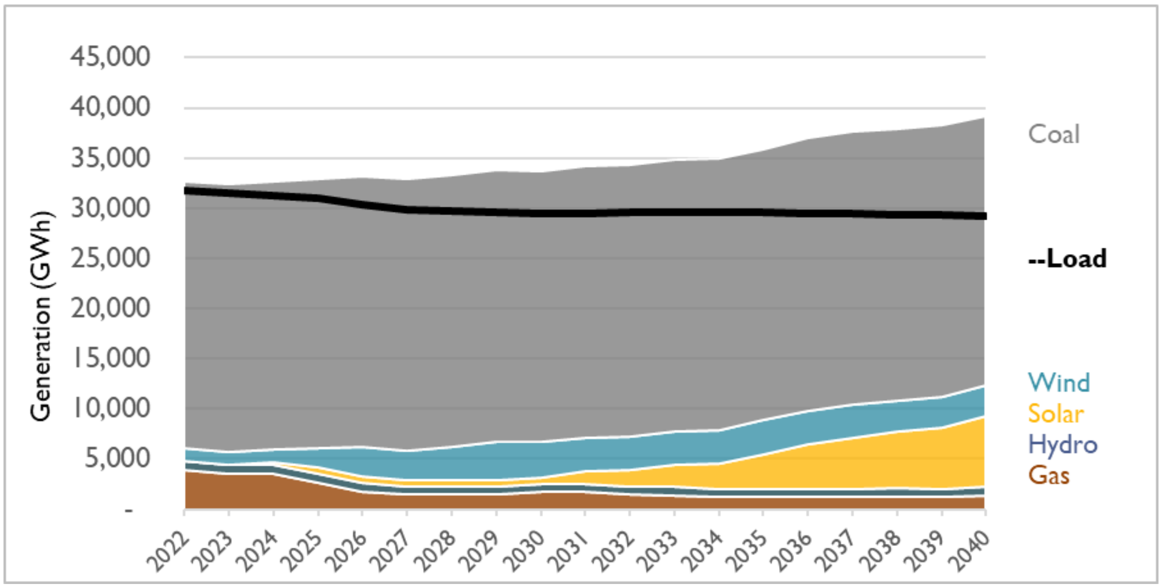
Table 8. Partial Coal Removal Scenario Cumulative New Capacity Builds (MW), Virginia Jurisdiction

Year	New PPA Wind	New Utility Wind	New PPA Solar	New Utility Solar	New Paired Solar	New Paired Battery	New Battery Storage	Capacity Market
2022	-	-	-	-	-	-	-	(75)
2023	-	-	-	-	-	-	-	(66)
2024	-	-	-	-	-	-	-	(72)
2025	60	-	-	-	3	1	25	(404)
2026	200	-	-	-	3	1	25	(304)
2027	350	-	-	-	3	1	25	(334)
2028	350	160	-	-	48	16	25	(380)
2029	350	310	-	-	93	31	25	931
2030	350	910	300	-	138	46	104	707
2031	350	1,150	600	-	183	61	104	587
2032	350	1,150	710	-	228	76	104	529
2033	350	1,720	710	-	273	91	288	277
2034	350	1,720	710	-	318	106	288	249
2035	350	1,720	710	-	339	113	288	236
2036	350	1,720	710	-	339	113	288	242
2037	350	1,720	710	-	339	113	288	239
2038	350	1,720	710	-	339	113	288	237
2039	350	1,720	710	-	339	113	288	230
2040	350	1,720	710	-	339	113	263	241

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

A. In the two 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 6 below.

Figure 6. Generation in Scenario 1, West Virginia PSC Preferred Case

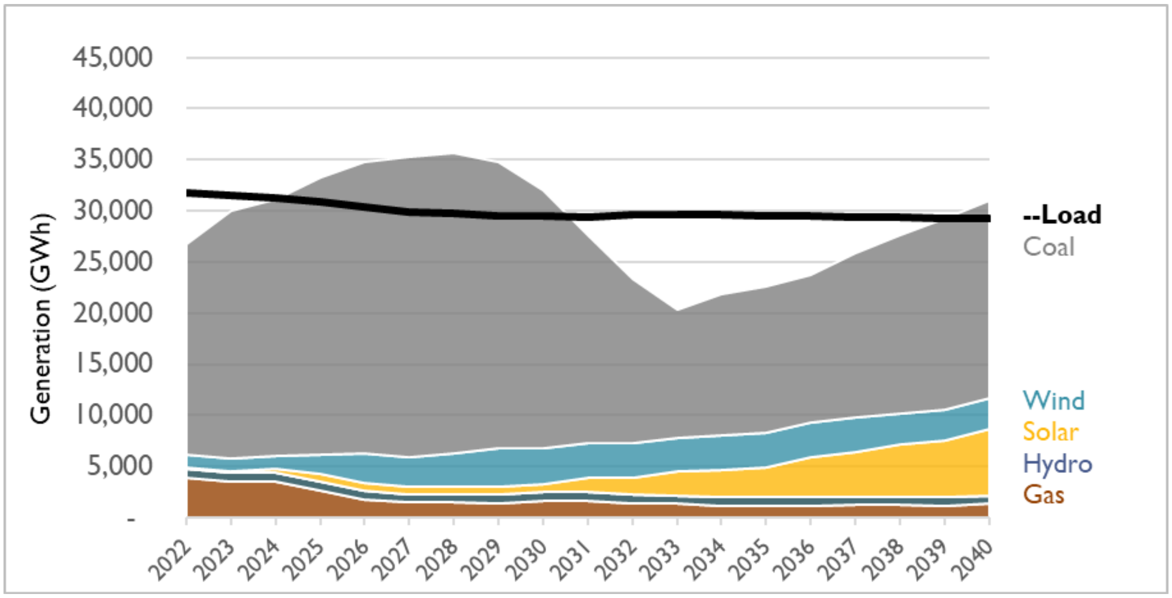


In Scenario 2, the APCo Preferred case, the Company's results show generation at APCo's thermal units, including both Amos and Mountaineer, increasing between 2022 and 2028.[31] After this time generation falls until 2032 and then grows more slowly until

31 *See* Company Response to Sierra Club Request No. 2-1 / Company Response to Sierra Club Request No. 2-2 in Case No. PUR-2022-00001, 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 provided to the Commission and properly authorized parties upon request.

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 Figure 7.

Figure 7: 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 8 and Figure 9 below.

Figure 8. Generation in Scenario 3, Full Coal Removal Case

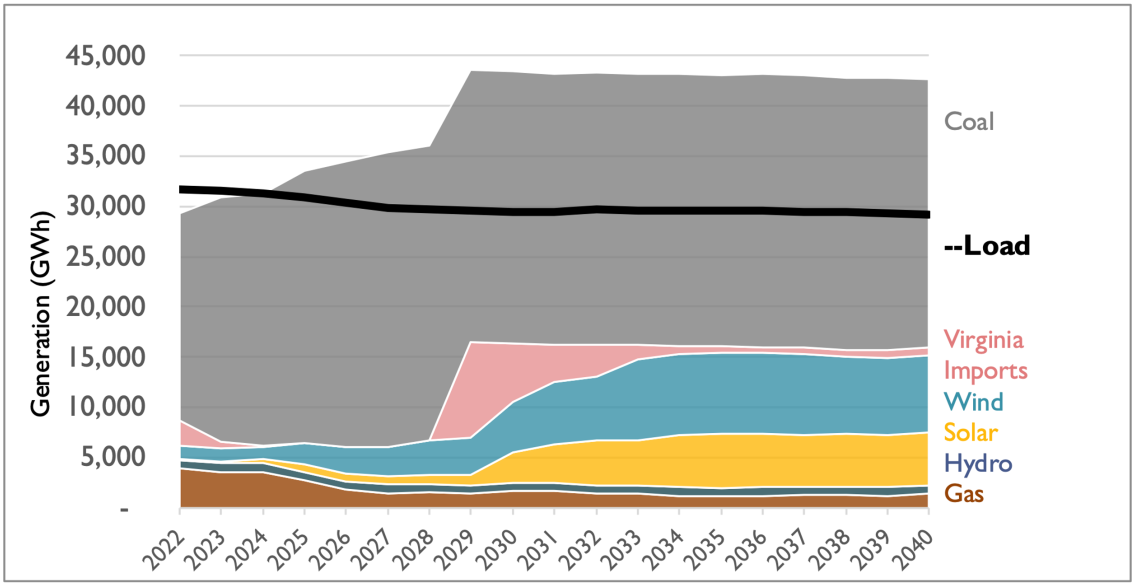
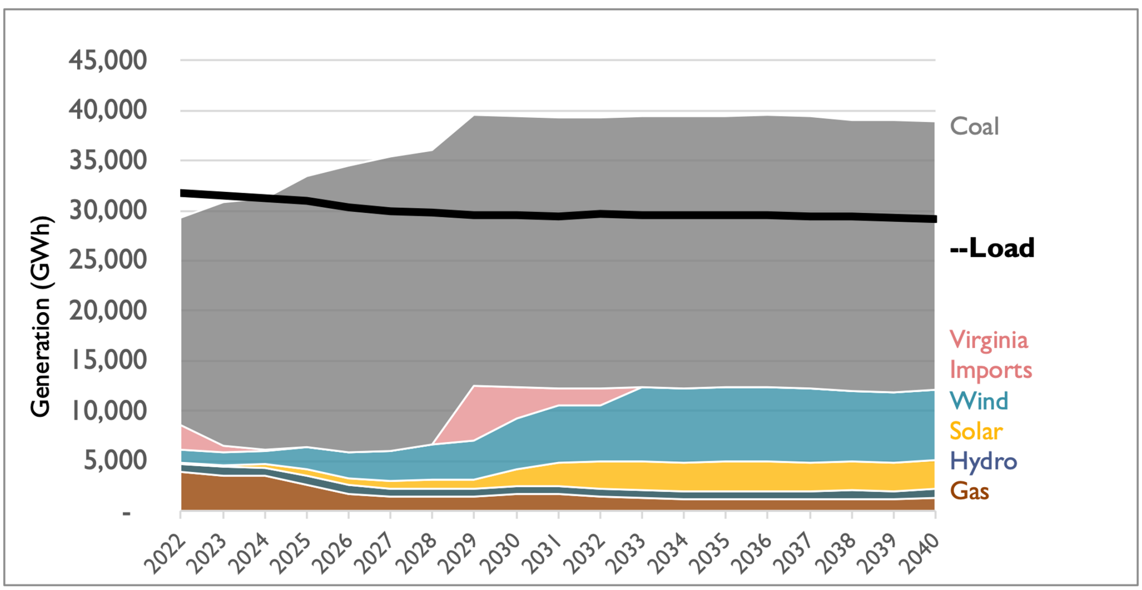


Figure 9. Generation in Scenario 4, Partial Coal Removal Case



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 15 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 7 and 8, 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 battery energy storage resources are built. This is consistent with the Company's own acknowledgment that there is no requirement that a certain amount of load be served by Company resources.[32]

Q, Why are the results of the analysis for the Full and Partial removal scenario different here than those presented in the ELG docket?

A. As discussed above, we updated our analysis to reflect the passage of the IRA. This means two things: (1) the full and partial removal portfolios we modeled in the ELG docket will now be cheaper than before; and (2) when given the option of selecting clean energy resources with the updated IRA prices, the model will optimize around a different, and even lower-cost, portfolio than we presented in the ELG case. Stated another way, the IRA doesn't just change the cost of the portfolios modeled in the ELG docket—it changes what resources the Company should build to replace Amos and Mountaineer.

32 Company Response to Sierra Club Request No. 5-10 in Case No. PUR-2022-00001, attached as Exhibit DG-14.

Table 9 below shows the revenue requirements that Synapse calculated in the ELG docket. This analysis was all conducted prior to the enactment of the IRA. We compare these results with the revenue requirements we calculated in the IRP docket. The IRP analysis includes the impact of the IRA on renewable cost assumptions. The results of all scenarios, both APCo's and Synapse's, drop by over $500 million. But more critically, the cost savings from Synapse's clean energy scenarios increase from -$12 million to $169 million in the Full Coal Removal Scenario and from $202 million to $264 million in the Partial Coal Removal Scenario.

Table 9: Synapse revenue requirements with and without the impact of the IRA

Scenario	Revenue Requirement for APCo's Virginia Ratepayers ($ Millions)				
	Without IRA (ELG Docket)		With IRA (IRP Docket)		Delta NPVRR Between ELG and IRP Dockets
	NPVRR*	Delta from WV PSC Preferred	Updated NPVRR	Delta from WV PSC Preferred	
1a. WVPSC Preferred	$5,915	-	$5,339	-	($576)
1b. WVPSC Preferred, High Coal Price	$6,089	$174	$5,513	$174	($576)
2. APCo Preferred	$5,743	($173)	$5,167	($173)	($576)
3. Full Coal Removal	$5,927	$12	$5,170	($169)	($757)
4. Partial Coal Removal	$5,713	($202)	$5,075	($264)	($638)

** Note: Does not include additional costs incurred as a result of VCEA non-compliance*

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

A. There are several important takeaways from the Synapse modeling analysis. First, the removal of Amos from the Virginia rate base in 2028 is the least-cost scenario and is in the best interests of Virginia ratepayers because it saves more than $264 million between 2022 and 2040. Removing both Amos and Mountaineer from the Virginia rate base will also save at least $169 million between 2022 and 2040.

Second, after accounting for the IRA, the impact of recent PJM policies lowering capacity market prices, and the risks of REC deficiencies and VCEA non-compliance, the relative benefits of removing both Amos and Mountaineer from the Virginia rate base increase substantially.

VI. LOCKING RATEPAYERS INTO COAL PLANTS THAT RUN REGARDLESS OF ECONOMICS PUTS RATEPAYERS AT RISK OF UNNECESSARY NET OPERATIONAL LOSSES

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

A. On September 2, 2021, the West Virginia PSC entered an Order in APCo's fuel-cost recovery docket that mandates: "The 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."[33] While the Company has argued that this issue is still pending before the West Virginia Commission,[34] it is my understanding that the West Virginia PSC has already denied APCo's motion to reconsider the September 2021 ruling and has since

33 *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.

34 Company's Response in Opposition to Sierra Club's Motion to Compel Discovery in Case No. PUR-2022-00001 at 7.

reinforced the 69-percent mandate in a subsequent order dated May 13, 2022.[35] As such, there is a real possibility that APCo will be required to dispatch the Plants uneconomically to comply with the 69-percent capacity factor mandate.

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.[36]

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

A. Amos Units 1 through 3 have been operating at an annual capacity factor of between 31 and 57 percent over the past five years as shown in Figure 10 below.[37] This is much lower than 69 percent. Mountaineer has operated at a capacity factor of between 49 and 71 percent over the past five years as shown in Figure 11 below.[38] Company data for

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35 *See*, *respectively*, *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 (March 2, 2022), available at https://bit.ly/391JIEl ;*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 (May 13, 2022), available at https://bit.ly/3O4k6Wr.

36 *Id.* at 9.

37 Company's Response to Sierra Club Request No. 3-04 Attachment 1, attached as Exhibit DG-15.

38 *Id.*

performance through July 2022 stated generally lower capacity factors across all four units of 23 to 49 percent.[39]

Figure 10: Amos Historical Capacity Factors

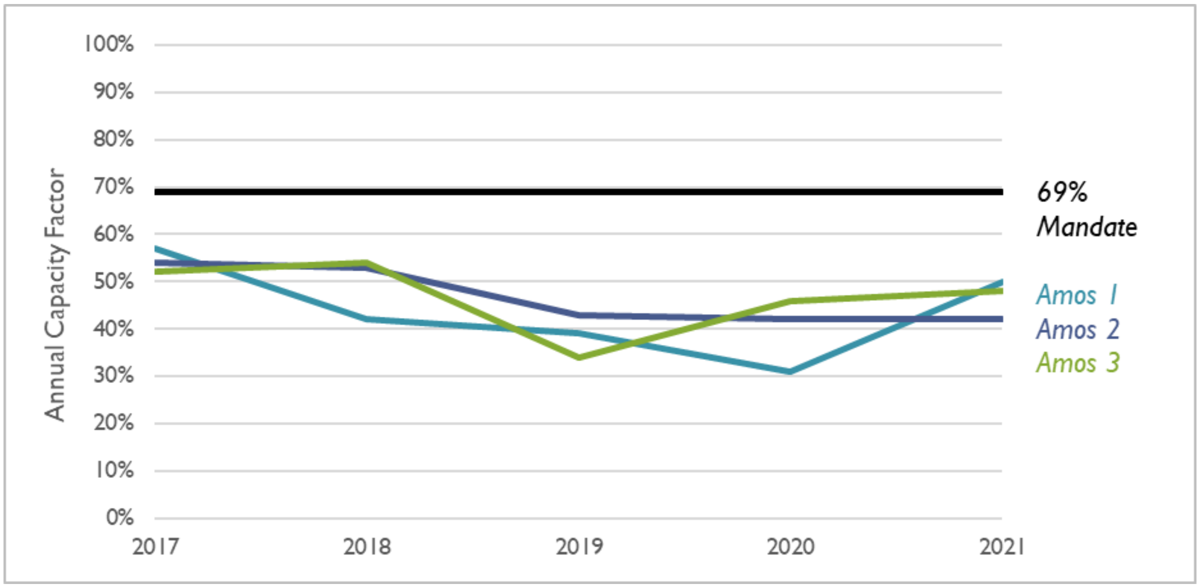
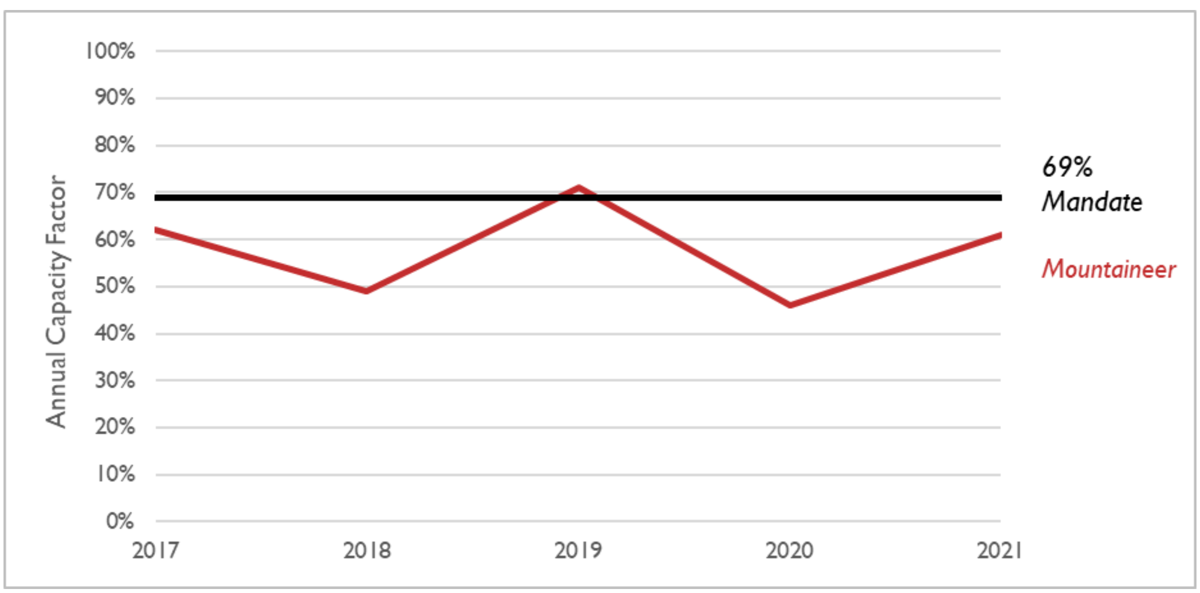


Figure 11: Mountaineer Historical Capacity Factors



39 *Id.*

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. The IRA is likely to exacerbate the impact of uneconomic operation by driving down market prices and furthering the gap between marginal costs and market prices. Given the potential costs this self-commitment practice could pass on to Virginia ratepayers, this risk should be fully considered in evaluating whether the Commission should approve the ELG costs at both Plants and whether the Company should be planning its future system on the assumption that both Plants will continue to operate until 2040. Because the IRP necessarily assumes that the Commission *will* approve those costs, the risk must also be considered in evaluating whether the IRP is reasonable and in the public interest.

VII. 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.[40] Looking beyond 2022, S&P Global Market Intelligence reports that 51 GW of coal power is scheduled to retire between 2022 and 2027, with an additional 23 GW of retirements coming in 2028.[41]

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-percent lower than the costs in 2009, with a compound annual rate of decline of 10 percent per year. Costs for solar are now 90 percent lower than in 2009, with a compound annual rate of decline of 18 percent per year. Figure 12 shows those annual trends. 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)

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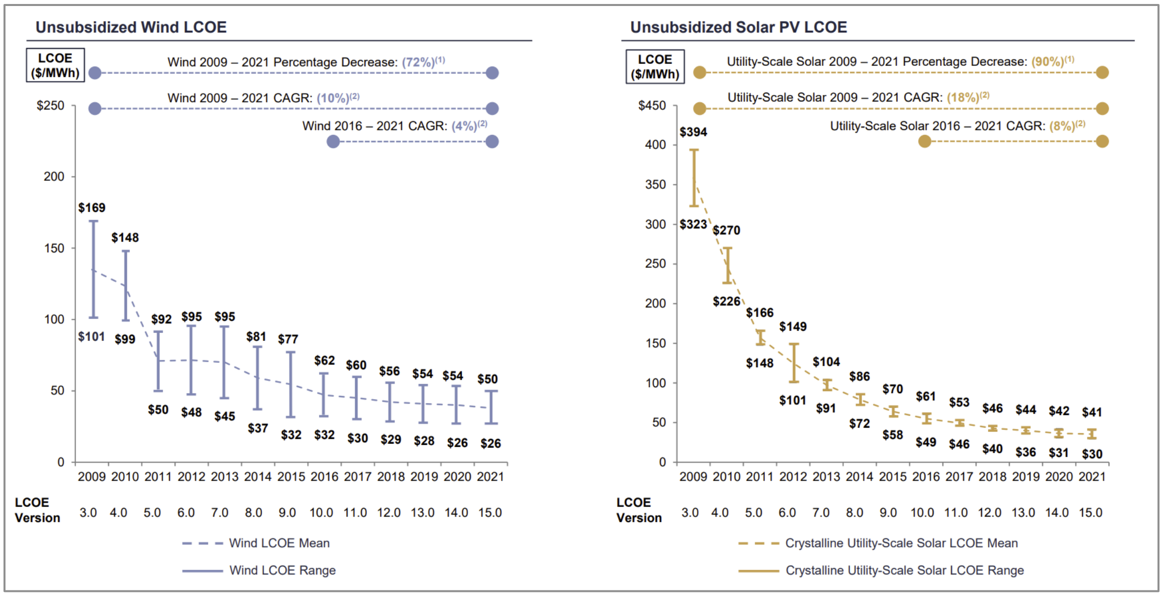
40 Energy Information Administration, *Coal Will Account for 85% of U.S. Electric Generating Capacity Retirements in 2022* (January 11, 2022), available at https://bit.ly/3MPZ4KE.

41 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.

comes back online.[42] The IRA is expected to drive down the cost of renewables moving forward.

Figure 12: 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.*

Q. Explain the impact that the Inflation Reduction Act will have on renewables.

A. The IRA provides $369 billion for climate and clean energy provisions, including extended tax credits for resources such as solar, wind, and storage through at least 2035. This long-term policy provides stability to the renewable energy sector and will continue to make replacement resources even more economic than existing fossil fuel generators.

42 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 some additional 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.[43] In 2019, Maryland legislators passed a bill that also increases its RPS to 50 percent by 2030.[44] The District of Columbia increased its RPS to 100-percent renewable energy by 2040.[45] 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.

VIII. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions.

A. First, I find that the Company's IRP modeling was insufficient to support APCo's proposed Hybrid Plan. Specifically, the Company did not model the removal of Amos or Mountaineer from Virginia. which could happen if ELG cost recovery is denied. Nor did

43 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.

44 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.

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

it model the impacts of the West Virginia 69-percent capacity factor mandate on the Plants' economics.

Second, I find that the Company's Retirement Analysis was insufficient and did not provide value to the Commission. Specifically, APCo failed to capture Virginia's potential to avoid ELG expenses by including 100 percent of environmental upgrade costs in the modeling and by fixing the retirement date for a single unit at a time rather than identifying the most economic retirement date for the portfolio.

Third, I find that the IRA further improves the economics of removing Amos and Mountaineer from the Virginia rate-base; thus, the Company should update all of its modeling with new renewable cost assumptions and market price forecasts that reflect the impact of the new and extended tax credits for renewable resources.

Fourth, my independent modeling demonstrates that it is uneconomic, and not in the best interest of Virginia ratepayers, for APCo to plan its future resource mix around the assumption that Virginia approves ELG cost recovery at Amos and Mountaineer and continues to operate the Plants through 2040. According to the modeling, removing Amos from the Virginia rate base beginning in 2029 will result in NPV savings of at least $264 million through 2040. The modeling further indicates that removing both Amos and Mountaineer from the Virginia rate base will result in an NPV savings of at least $169 million, as shown in Table 3.

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.

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 reject APCo's IRP and limited Retirement Analysis and require the Company's modeling to include:

- a scenario that reflects the Commission's ruling in Case No. PUR-2022-00001;
- a scenario in which Amos and Mountaineer must operate at a 69-percent capacity factor per the West Virginia Commission Order;
- updated renewable cost assumptions for solar PV, wind, and battery storage that are consistent with the tax credits included in the Inflation Reduction Act; and
- updated market energy prices that reflect the impact of lower cost renewables costs on the PJM energy market.

Q. Does this conclude your direct testimony?

A. Yes.

DIRECT TESTIMONY OF DEVI GLICK

INDEX OF EXHIBITS

No.	Exhibit
DG-1	Resume of Devi Glick
DG-2	Company Response to Environmental Respondent Discovery Request No. 4-01
DG-3	Company Response to Staff Discovery Request No. 9-81
DG-4	Company Response to Sierra Club Discovery Request No. 1-06
DG-5	Company Response to Sierra Club Discovery Request No. 3-05
DG-6	Company Response to Sierra Club Request No. 6-04 (Case No. PUR-2022-00001)
DG-7	Company Response to Staff Discovery Request No. 7-70 Attachment 1
DG-8	Company Response to Sierra Club Discovery Request No. 1-15
DG-9	Company Response to Sierra Club Discovery Request No. 1-07
DG-10	Company Response to Sierra Club Request No. 2-03 (Case No. PUR-2022-00001)
DG-11	Company Response to Sierra Club Request No. 7-04 (Case No. PUR-2022-00001)
DG-12	Company Response to Sierra Club Discovery Request No. 2-03 Attachment 6 (Case No. PUR-2022-00001)
DG-13	Company Response to Sierra Club Request No. 5-09 (Case No. PUR-2022-00001)
DG-14	Company Response to Sierra Club Request No. 5-10 (Case No. PUR-2022-00001)
DG-15	Company Response to Sierra Club Request No. 3-04 Attachment 1

EXHIBIT DG-1

Resume of Devi Glick

Devi Glick, Senior Principal

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7050
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017

Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.

- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

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Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

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Iowa Utilities Board (Docket No. RPU-2022-0001): Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles." On behalf of Environmental Intervenors. July 29, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00006): Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

Oklahoma Corporation Commission (Case No. PUD 202100164): Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

Public Utility Commission of Texas (PUC Docket No. 52485): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

Public Utility Commission of Texas (PUC Docket No. 52487): Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

Michigan Public Service Commission (Case No. U-21052): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

Arkansas Public Service Commission (Docket No. 21-070-U): Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

New Mexico Public Regulation Commission (Case No. 21-00200-UT): Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

Arkansas Public Service Commission (Docket No. 21-070-U): Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

Michigan Public Service Commission (Case No. U-20528): Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

Public Utilties Commission of Ohio (Case No. 20-167-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

Public Service Commission of South Carolina (Docket No, 2021-3-E): Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

North Carolina Utilities Commission (Docket No. E-2, Sub 1272): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

Michigan Public Service Commission (Docket No. U-20530): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase I Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. On behalf of the Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Public Utility Commission of Texas (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 23, 2018.

Resume updated August 2022

EXHIBIT DG-2

Company Response to Environmental Respondent Discovery Request No. 4-01

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00051
Interrogatories and Requests for the Production
of Documents by the ENVIRONMENTAL RESPONDENTS
ER Set 4
To Appalachian Power Company

Interrogatory ER 4-1:

In the modeling performed for APCo's unit retirement analysis for the Amos and Mountaineer coal units, please confirm that the modeling was based on the assumption that the coal units are dispatched by the PJM system operator based on economic dispatch. If the retirement analysis modeling assumptions deviated from economic dispatch, please identify the correct unit dispatch assumptions used in the modeling.

Response ER 4-1:

Confirmed.

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

EXHIBIT DG-3

Company Response to Staff Discovery Request No. 9-81

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00051
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Set 9
To Appalachian Power Company

Interrogatory Staff 9-81:

For each of the portfolios presented in the IRP (Portfolios A through S), please provide the following information: Do the net present value ("NPV") costs associated with each portfolio include continued recovery of the existing undepreciated plant costs associated with the Amos and Mountaineer generating facilities currently recovered in base rates? (b) Do the NPV costs associated with each portfolio include the costs associated with the effluent limitation guidelines ("ELG") upgrade costs the Company is currently seeking approval for recovery of in Case No. PUR-2022-00001?

Response Staff 9-81:

a) None of ten Portfolios A-J have recovery of the existing undepreciated net book value (NBV) as of December 31, 2021 in them. These are all portfolios in which all four of the Amos and Mountaineer units retire in 2040, which is either at the same time or after they are scheduled to be fully depreciated in both APCo states. Existing NBV is considered to be sunk costs and the Company has excluded them under the assumption they would be recovered equally in all of these 10 scenarios. Depreciation rates in each state are expected to result in full recovery of the existing 2021 balance by 2040 or earlier, and therefore, absent changes in depreciation rates, it is assumed that all of the existing NBV will have been recovered when the units retire in 2040 under those portfolios.
In the nine unit-retirement Portfolios K-S, each Portfolio has one unit retiring early in either 2028 or 2034. As a result the existing NBV will likely not be recovered equally in all scenarios, and the Company accounted for that through an assumed post retirement recovery of any balance left at retirement through a Regulatory Asset surcharge or other cost-recovery mechanism over the three years following the retirement. The Company prepared a forecast of Virginia-basis net book value including future capital expense between 2022 and the retirement date and depreciation expense based on current Virginia depreciation rates for every unit in these nine scenarios in order to produce these undepreciated balance estimates.
For the three non-retiring units in each of those Portfolios K-S, similar to cases A-J, the existing 2021 NBV of these units is excluded as sunk cost. For the retiring unit, if there is projected to be undepreciated NBV on the date of retirement using the currently in effect Virginia depreciation rates, the portion of the existing 2021 NBV that remains undepreciated at retirement in either 2028 or 2034 is included in the costs of the Portfolio. The portion of the existing NBV that had been depreciated by the retirement date is excluded from the Portfolio cost, in order to allow for better comparability by keeping the treatment of the non-retiring units the same as they were

Response Staff 9-81 cont'd:

treated in Portfolios A-J. For the Amos units, which will be fully depreciated for Virginia in 2032 or 2033 if existing Virginia depreciation rates remain unchanged, none of the existing 2021 NBV will be remaining undepreciated at 2034, so there is no undepreciated NBV included in Portfolios L and O.

b) Yes. The full ELG cost is included in all portfolios. The IRP portfolios are total company views. The ELG investments are being made and thus those costs should be included.

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

EXHIBIT DG-4

Company Response to Sierra Club Discovery Request No. 1-06

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00051
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 1
To Appalachian Power Company

Interrogatory SC 1-06:

Reference Sections 2.4.4.1.2 and 4.3 of the 2022 IRP 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-percent 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-percent 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 SC 1-06:

(a) No. 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 experiencing difficulty procuring coal based on current market conditions. See also the Company's response to SC 1-3.
(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 DG-5

Company Response to Sierra Club Discovery Request No. 3-05

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00051
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 3
To Appalachian Power Company

Interrogatory SC 3-5:

Has the Company conducted any PLEXOS modeling that incorporates the tax credit changes set forth in the Inflation Reduction Act?
(a) If yes, please provide all relevant workpapers and results from this modeling.
(b) If no, please explain why the Company has not done so.

Response SC 3-5:

No. The Company is currently evaluating the impacts of the Inflation Reduction Act.

The foregoing response is made by Gregory J. Soller, Resource Planning Mgr, on behalf of Appalachian Power Company.

EXHIBIT DG-6

Company Response to Sierra Club Discovery Request No. 6-04 (Case No. PUR-2022-00001)

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.

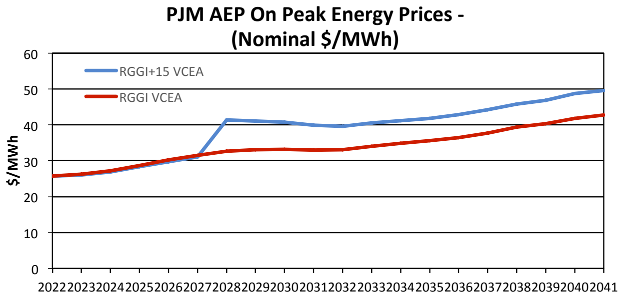
Response SC 6-04:

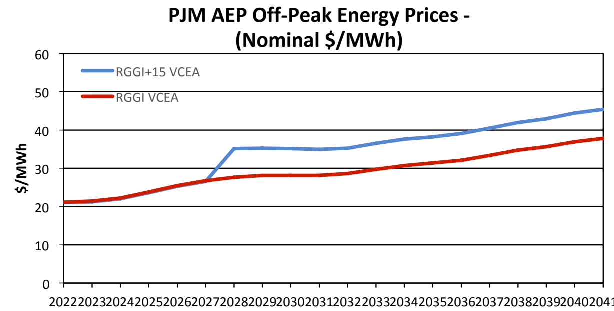
a. The Fundamentals Forecast was created in July 2021.
b. No, the Company does not have an updated capacity price forecast since the July 2021 Fundamentals forecast. It is too early to know whether the change in PJM's minimum offer price rule would impact the accuracy of the Company's Fundamentals forecast.

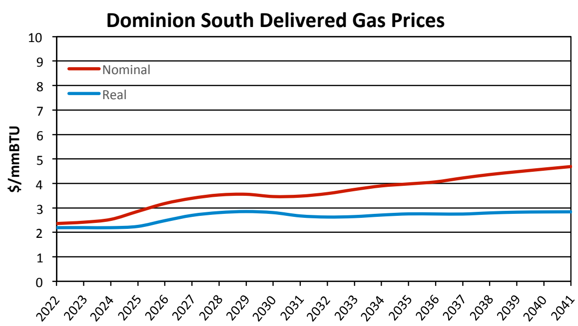
The foregoing response is made by James F. Martin, Dir Resource Planning Strategy, on behalf of Appalachian Power Company.

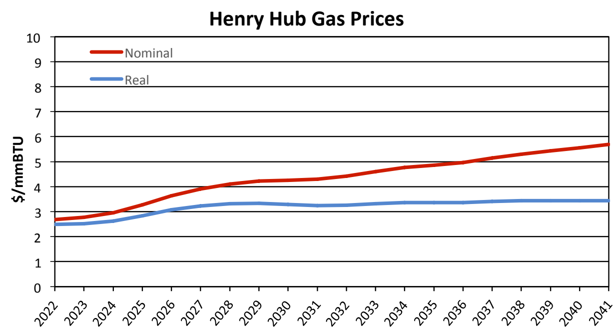
EXHIBIT DG-7

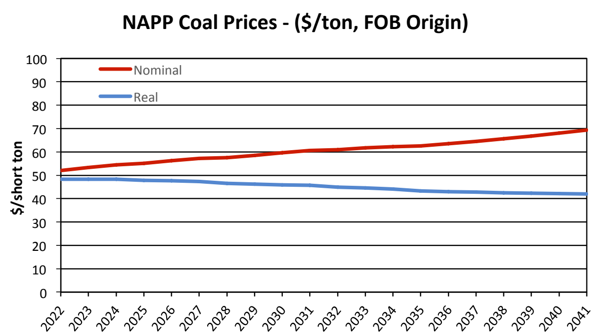
Company Response to Staff Discovery Request No. 7-70 Attachment 1

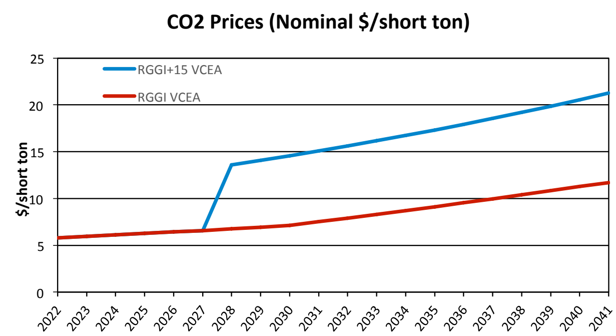

PJM AEP On Peak Energy Prices - (Nominal $/MWh)
$/MWh
RGGI+15 VCEA
RGGI VCEA

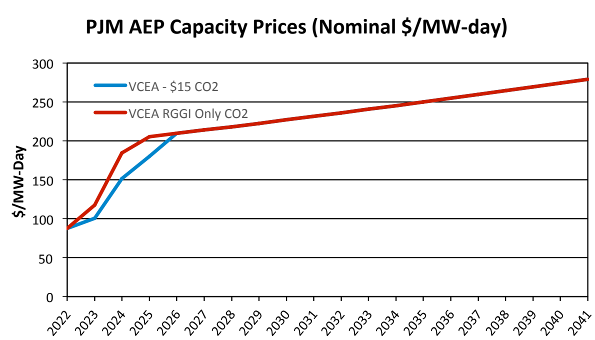

PJM AEP Off-Peak Energy Prices - (Nominal $/MWh)
$/MWh
RGGI+15 VCEA
RGGI VCEA


Dominion South Delivered Gas Prices
$/mmBTU
Nominal
Real


Henry Hub Gas Prices
$/mmBTU
Nominal
Real


NAPP Coal Prices - ($/ton, FOB Origin)
$/short ton
Nominal
Real


CO2 Prices (Nominal $/short ton)
$/short ton
RGGI+15 VCEA
RGGI VCEA


PJM AEP Capacity Prices (Nominal $/MW-day)
$/MW-Day
VCEA - $15 CO2
VCEA RGGI Only CO2

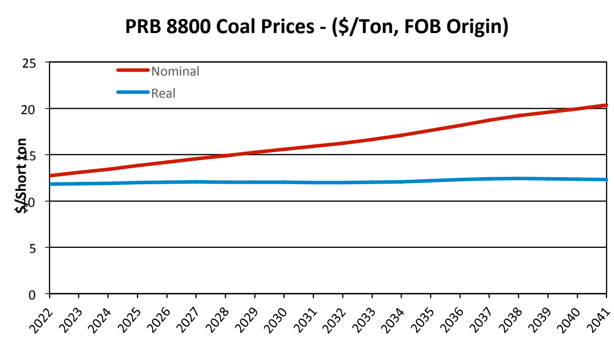

PRB 8800 Coal Prices - ($/Ton, FOB Origin)
$/Short ton
Nominal
Real

EXHIBIT DG-8

Company Response to Sierra Club Discovery Request No. 1-15

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00051
Interrogatories and Requests for the Production of Documents by the SIERRA CLUB
Sierra Club Set 1
To Appalachian Power Company

Interrogatory SC 1-15:

Please provide the most recent Fundamental Forecast produced by the Company.

Response SC 1-15:

The Fundamental Forecast provided in the response to SC 1-14 is the most current forecast.

The foregoing response is made by Gregory J. Soller, Resource Planning Mgr, on behalf of Appalachian Power Company.

EXHIBIT DG-9

Company Response to Sierra Club Discovery Request No. 1-07

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2022-00051
Interrogatories and Requests for the Production
of Documents by the SIERRA CLUB
Sierra Club Set 1
To Appalachian Power Company

Interrogatory SC 1-07:

Regarding the Company's procurement of coal over the past three years, please state whether the Company has faced any coal shortages at Amos or Mountaineer.

Response SC 1-07:

It has.

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

EXHIBIT DG-10

Company Response to Sierra Club Discovery Request No. 2-03 (Case No. PUR-2022-00001)

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 DG-11

Company Response to Sierra Club Discovery Request No. 7-04 (Case No. PUR-2022-00001)

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 DG-12

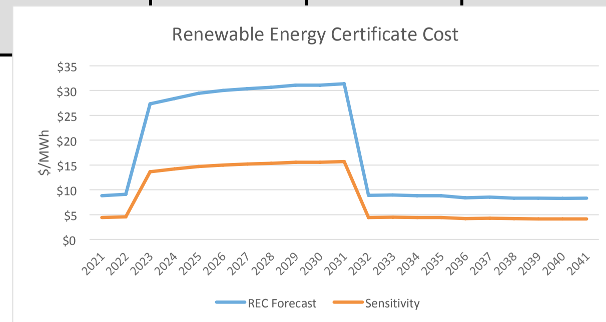
Company Response to Sierra Club Discovery Request No. 2-03 Attachment 6 (Case No. PUR-2022-00001)

S&P Global
Market Intelligence

Market Intelligence Renewable Energy Certificate Price Forecast (Data)

Forecast Release: Q2 2021
Frequency: Annual
Date Range: 01/01/2021 - 01/01/2041
Location: PJM

Date	MD Solar $/MWh	MD Tier I $/MWh	DC Tier I $/MWh	NJ Class I $/MWh	OH REC $/MWh	PA Solar $/MWh	PA Tier I $/MWh	VA Class I $/MWh		
01/01/2021	78.50	14.65	5.80					8.83	2021	4.41
01/01/2022	59.38	14.79	6.99					9.13	2022	4.56
01/01/2023	33.33	33.33	7.22					27.35	2023	13.67
01/01/2024	9.65	28.37	7.69					28.37	2024	14.18
01/01/2025	10.21	8.29	8.29					29.44	2025	14.72
01/01/2026	10.20	8.53	8.53					30.00	2026	15.00
01/01/2027	9.92	9.92	8.68					30.38	2027	15.19
01/01/2028	9.63	9.63	8.78					30.66	2028	15.33
01/01/2029	9.37	8.99	8.99					31.08	2029	15.54
01/01/2030	9.01	8.86	8.86					31.09	2030	15.55
01/01/2031	8.86	8.97	8.97					31.36	2031	15.68
01/01/2032	8.31	8.31	8.31					8.89	2032	4.45
01/01/2033	7.96	8.94	7.96					8.94	2033	4.47
01/01/2034	7.54	8.82	7.54					8.82	2034	4.41
01/01/2035	7.14	7.14	7.14					8.80	2035	4.40
01/01/2036	6.28	6.28	6.28	6.28	8.42	6.28	8.42	8.42	2036	4.21
01/01/2037	6.29	8.54	6.29	6.29	8.54	6.29	8.54	8.54	2037	4.27
01/01/2038	5.48	8.35	5.48	5.48	8.35	5.48	8.35	8.35	2038	4.17
01/01/2039	5.00	5.00	5.00	5.00	8.33	5.00	8.33	8.33	2039	4.17
01/01/2040	4.65	4.65	4.65	4.65	8.28	4.65	8.28	8.28	2040	4.14
01/01/2041	4.52	8.32	4.52	4.52	8.32	4.52	8.32	8.32	2041	4.16



Market Intelligence's price forecasts are provided in nominal dollars.

EXHIBIT DG-13

Company Response to Sierra Club
Discovery Request No. 5-09
(Case No. PUR-2022-00001)

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 DG-14

Company Response to Sierra Club Discovery Request No. 5-10 (Case No. PUR-2022-00001)

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 DG-15

Company Response to Sierra Club Discovery Request No. 3-04 Attachment 1

Unit	Year	Net Cap Ftr (NCF)
AM1	2017	57.04
AM1	2018	41.69
AM1	2019	39.43
AM1	2020	31.23
AM1	2021	50.22
AM1	2022*	48.63
AM2	2017	53.97
AM2	2018	53.48
AM2	2019	43.19
AM2	2020	41.87
AM2	2021	41.86
AM2	2022*	28.18
AM3	2017	52.47
AM3	2018	54.21
AM3	2019	34.40
AM3	2020	45.51
AM3	2021	47.71
AM3	2022*	23.44
MT1	2017	61.81
MT1	2018	49.38
MT1	2019	71.40
MT1	2020	45.50
MT1	2021	61.70
MT1	2022*	32.75

*through July 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 September 2, 2022, I sent the foregoing by electronic mail to:

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