AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY

American Electric Power
1051 E Cary Street, Suite 1100
Richmond, Virginia 23219
AEP.com

210930023

September 14, 2021

By Hand **PUBLIC VERSION**

Hon. Bernard J. Logan, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street, First Floor
Richmond, Virginia 23219

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2021 SEP 14 P 2: 02

SCC-CLERK'S OFFICE
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Re: Application of Appalachian Power Company To increase its fuel factor pursuant to § 56-249.6 of the Code of Virginia Case No. PUR-2021-00205

Dear Mr. Logan:

Enclosed for filing please find an original and four copies of the Public version of Appalachian Power Company's Application to increase its fuel factor pursuant to § 56-249.6 of the Code of Virginia.

The Company is also filing today under separate cover an original and 15 copies under seal of the Confidential version of this Application.

Sincerely,

Noelle J. Coates

Enclosures

cc: William H. Chambliss, Esq. (Letter only)
C. Meade Browder, Jr., Esq.

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF	)	
	)	
APPALACHIAN POWER COMPANY	)	CASE NO. PUR-2021-00205
	)	
To increase its fuel factor pursuant to	)	
§ 56-249.6 of the Code of Virginia	)	

APPLICATION

September 14, 2021

(PUBLIC VERSION)

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Counsel for Appalachian Power Company

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF	)	
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Application

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

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	)	
To increase its fuel factor pursuant to Va. Code § 56-249.6	)	

APPLICATION

Pursuant to Section 56-249.6 of the Code of Virginia and 20 VAC 5-204-80, Appalachian Power Company ("Appalachian," "APCo," or the "Company") files this Application with the State Corporation Commission ("Commission") for approval of a revision of its fuel factor. Specifically, the Company proposes to increase the current fuel factor of 1.999 ¢/kWh to 2.300 ¢/kWh effective November 1, 2021 through October 31, 2022 (the "fuel year"), which is an annual net increase in the revenue of approximately $42 million. In support of the Application, the Company states as follows:

1. Appalachian is a Virginia public service corporation serving approximately 530,000 customers in Virginia with its main office in Charleston, West Virginia and offices at Three James Center, 1051 East Cary Street, Suite 1100, Richmond, Virginia 23219. The Company sells electricity to retail customers in southwestern Virginia and southern West Virginia. Its Virginia jurisdictional retail rates and service are subject to regulation by the Commission. The names and addresses of the Company's legal counsel are listed at the foot of this Application.

2. The following witnesses offer testimony in support of this Application:

- ***Kimberly K. Chilcote***, Coal Procurement Manager, Commercial Operations, American Electric Power Service Corporation ("AEPSC"). Ms. Chilcote provides APCo's procurement strategy, provides an overview of the coal market in which the Company procures coal and discusses the long-term coal contracts currently providing coal supplies. These elements support the conclusion that the delivery forecast, as provided for the twelve-month period of November 1, 2021 through October 31, 2022, is reasonable.

- ***Shelli A. Sloan,*** Director Financial Support and Special Projects (AEPSC). Ms. Sloan provides the estimate of APCo's total company Net Energy Requirement of 31,852.4 GWh, and includable cost of $592.4 million, to Company witness Keeton for use in determining APCo's proposed Virginia jurisdictional fuel factor for the period November 2021 – October 2022.

- ***Clinton M. Stutler***, Natural Gas and Fuel Oil Manager for AEPSC. Mr. Stutler discusses the three natural gas-fired power plants owned and operated by the Company; provides an overview of the natural gas market in which Appalachian procures gas; and discusses the Company's natural gas procurement strategy, including the Company's natural gas transportation agreements. He also supports the conclusion that the forecast for natural gas delivery, as provided for the twelve-month period from November 1, 2021 through October 31, 2022, is reasonable.

- ***Eleanor K. Keeton,*** Regulatory Consultant for Appalachian. Ms. Keeton's testimony supports the proposed fuel factor of 2.300 ¢/kwh to become effective November 1, 2021.

3. The Commission approved Appalachian's current fuel factor of 1.999¢/kWh in Case No. PUR-2020-00163, and it has been in effect since November 1, 2020.[1]

4. As Company witness Keeton describes, the implementation of the proposed fuel factor will produce an estimated annual net increase of approximately $42 million.

5. In this Application, the Company proposes a fuel factor comprised of two components: an "in-period" component designed to recover on-going costs; and a "prior-period" component designed to recover the Company's unrecovered deferred balance. Appalachian proposes an in-period fuel factor component of 2.021¢/kWh to recover the projected Virginia jurisdictional fuel costs for November 1, 2021 through October 31, 2022.

[1] Order Establishing 2020-2021 Fuel Factor, *Application of Appalachian Power Company To reduce its fuel factor*, Case No. PUR-2020-00163, Doc. Con. Cen. No. 210310075 (March 3, 2021).

6. In addition, the Company proposes to set the prior-period component of the fuel factor at 0.279 ¢/kWh to recover the estimated deferred under-recovery balance of approximately $38.8 million (as of October 31, 2021) over the upcoming fuel year.

7. The combination of these two components results in the proposed fuel factor of 2.300 ¢/kWh, as supported by Company witness Keeton.

8. The Company's projections for fuel costs continue to reflect an offset to projected fuel costs for 75% of the Company's projected off-system sales margins for the fuel year pursuant to Virginia Code § 56-249.6 D 1. In addition, the projections credit against fuel costs 100% of the financial transmission rights received through PJM auction revenue rights and 100% of transmission line loss margins rather than reflecting either of them in lower off-system sales margin credits at 75%.

9. The Company's fuel projections also reflect recovery of the non-incremental costs of wind power purchase contracts. The projected non-incremental costs of Appalachian's wind power purchases were developed using the methodology adopted by the Commission in Case No. PUE-2015-00034.[2]

10. The Application and filing follow the applicable requirements contained in 20 VAC 5-204-10, 20 VAC 5-204-80, and 20 VAC 5-204-90. The Company has prepared an appendix to its Application incorporating the relevant information required by 20 VAC 5-204-80 and 20 VAC 5-204-90, including the actual information for each month for the most recent

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[2] Final Order, *Petition of Appalachian Power Company, for approval of a rate adjustment clause, RPS-RAC, to recover the incremental costs of participation in the Virginia renewable energy portfolio standard program pursuant to Va. Code §§ 56-585.1 A 5 d and 56-585.2 E*, Case No. PUE-2015-00034 (Nov. 16, 2015). Note that the Commonwealth's voluntary Renewable Portfolio Standard ("RPS") was replaced by a mandatory RPS established by the Virginia Clean Economy Act ("VCEA") in 2020. The incremental costs associated with the approved wind power purchase contracts will be addressed in the Company's required VCEA filing in November.

historical 12-month period of July 2020 through June 2021 and projections for the period November 2021 through October 2022.

11. Under Rule 20 VAC 5-204-80, this filing necessarily contains confidential and/or proprietary information ("Confidential Information"). This Confidential Information is filed under seal and will be made available to respondent parties upon execution of an appropriate confidentiality agreement and entry of a protective ruling. Pursuant to Rate Case Rule 20 VAC 5-20-204-10 F and the Commission's Rules of Practice and Procedure Rules 5 VAC 5-20-110 and 5 VAC 5-20-170, Appalachian is filing a Motion for Protective Ruling and accompanying proposed Protective Ruling contemporaneously with this Application.

WHEREFORE the Company respectfully requests that the Commission issue an order that (1) authorize implementation of a revised fuel factor of 2.300 ¢/kWh effective for service rendered November 1, 2021 through October 31, 2022; and (ii) grant such other or further relief as may be necessary or appropriate to effect the intent of this Application.

September 14, 2021

Respectfully submitted,

APPALACHIAN POWER COMPANY

By ______________________
Counsel

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Counsel for Appalachian Power Company

APCo Exhibit No. ___
Witness: KKC

**DIRECT TESTIMONY OF
KIMBERLY K. CHILCOTE
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2021-00205**

APCo Exhibit No. ___
Witness: KKC

21093000023

SUMMARY OF DIRECT TESTIMONY OF KIMBERLY K. CHILCOTE

My direct testimony provides APCo's procurement strategy, provides an overview of the coal market in which Appalachian Power Company (APCo or the Company) procures coal and discusses the long-term coal contracts currently providing coal supplies. These elements support the conclusion that the delivery forecast, as provided for the twelve-month period of November 1, 2021 through October 31, 2022, is reasonable.

APCo Exhibit No. ___
Witness: KKC

DIRECT TESTIMONY OF
KIMBERLY K. CHILCOTE
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2021-00205

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Kimberly K. Chilcote. I am employed by American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), in the regulated Commercial Operations organization as Coal Procurement Manager. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the University of Dayton in 1992 with a Bachelor of Chemical Engineering Degree.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I joined AEP in 1992 as an Assistant Chemist at the Conesville Plant and transferred to the fuels group in 2004 as a Coordinator performing quality checks of the coal purchased by the procurement department. I transferred in 2007 to the Western Procurement group and was responsible for the purchase and shipment of all of the Powder River Basin Coal for the AEP System. In 2008, I transferred to the Eastern Procurement group to purchase coal for Columbus Southern Power and Ohio Power, AEP Ohio. In 2010 I was promoted to manager of coal procurement for AEP Ohio and Kentucky Power. In 2014, I joined AEP Generation Resources with responsibilities for purchasing coal, natural gas and consumables for AEPs unregulated plants. In 2020, I accepted a position in the regulated Commercial

Operations organization in the coal and reagents transportation team. I was promoted to my current position as Coal Procurement Manager in May of 2021.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS COAL PROCUREMENT MANAGER FOR AEPSC?

A. I am responsible for managing coal procurement, contract oversight, and inventory management activities for the following AEP operating companies, including Appalachian Power Company, Wheeling Power Company (WPCo), Indiana & Michigan Power Company (I&M), Kentucky Power Company (KPCo), Southwestern Electric Power Company (SWEPCO), Public Service Company of Oklahoma (PSO), and as an agent for, Ohio Valley Electric Corporation and Indiana Kentucky Electric Corporation.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AGENCIES?

A. Yes. I have provided written testimony and testified on the stand before the Kentucky Public Service Commission on behalf of Kentucky Power Company for previous fuel review proceedings.

I. PURPOSE

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

A. The purpose of my testimony in this proceeding is to:

1) Discuss APCo's coal purchasing strategy;
2) Provide an overview of the coal market in which APCo procures coal;
3) Describe the coal delivery forecast for the twelve-month period from November 1, 2021 through October 31, 2022 (Forecast Period); and
4) Describe APCo's portfolio of coal supply agreements.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes. I am sponsoring APCo Exhibit No. ___ (KKC) Schedule 1, which is a list of long-term coal supply agreements that will be in effect during the Forecast Period.

II. COAL PURCHASING STRATEGY

Q. PLEASE DESCRIBE APCO'S COAL PURCHASING STRATEGY.

A. Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies related to planned as well as unplanned outages to maintain appropriate coal inventory levels. To meet these requirements, APCo's purchasing strategy utilizes solicitations requesting competitive offers for coal to layer in a portion of supply needs over time. Coal supply is solicited through open Requests for Proposals by specifying the quantity, quality, and logistical parameters sought for each plant. From qualifying offers, APCo makes its selection of the coal needed to meet its requirements, based on the lowest reasonable delivered cost, including the consideration of price, coal quality, ability to deliver, past performance, and the financial status of suppliers. This practice lowers the risk and enhances APCo's security of supply. Additionally, at times unsolicited and over-the-counter coal may be purchased due to Company need exceeding what is provided through the process identified above. In these situations, APCo evaluates these purchases against the market and any recent solicitation results to ensure reliable supplies of coal at reasonable prices.

Q. WHAT IS APCO'S STRATEGY FOR PROCURING COAL VIA LONG-TERM VERSUS SHORT-TERM AGREEMENTS?

A. The Company consumes both high-sulfur, Northern Appalachian (NAPP) coal and low-sulfur, Central Appalachia (CAPP) coal in its coal-fired plants to meet the requirements of the electricity generating units and the installed environmental equipment. The Company's strategy includes layering short-term, agreements with a term of one year or less, and long-term coal supply agreements into the portfolio to gradually increase the committed position. By layering in commitments over time the Company maintains an uncommitted (also known as "Non-Committed") tonnage, which is often referred to as the Open Position. Maintaining an Open Position decreases the risk of being over-supplied in a year with lower than forecasted consumption. Additional spot purchases are made closer to when the Open Position tonnage is required. These purchases are subject to market price volatility, but also provide increased flexibility in meeting the demands of each plant. With the current global pandemic situation and unpredictable natural gas prices, the demands of the plants remain as volatile as they have been in the past several years.

III. MARKET OVERVIEW

Q. PLEASE DESCRIBE RECENT CHANGES IN THE COAL MARKET.

A. Calendar year 2020 saw an unprecedented loss of demand for electricity due primarily to the COVID-19 global pandemic. This crisis, when combined with historically low natural gas prices, created an environment of exceptionally weak power prices. As a result, the demand for U.S. coal generation decreased by approximately 20% in 2020 as compared to 2019 (EIA Fossil Fuels for Electricity

Generation).[1] As the country, and the world, opened back up in 2021, the price of natural gas rose and the demand for coal recovered. In the first 5 months of 2021, coal generation was approximately 35% higher year on year. The turnaround in demand led to an increase in coal prices, as well. From mid-2020 to mid-2021, the prompt quarter price[2] published for low-sulfur barge coal (12,000 Btu per lb. 1.67 lbs. SO_2) increased \$23.00 per ton to approximately \$63.50 per ton and the cost of CSX rail coal, (12,500 Btu per lb. 1.60 lbs. SO_2) increased by over \$25 per ton to approximately \$67.00 per ton. The high-sulfur (12,500 Btu per lb. 6 lbs. SO_2) coal markets also saw price spike, as was reflected in the market price for this type of coal rising to approximately \$52.00 per ton or just over \$16 per ton more than the previous year. A Request for Proposals (RFP) issued by AEPSC in May of 2021 yielded several CAPP offers that were in-line with the current market price of \$54.85 per ton for 2022.[2] Similarly, the RFP responses for NAPP coal were consistent with the then published market price of \$38.75 per ton for 2022.

Q. PLEASE DESCRIBE THE IMPACT THE MARKET CONDITIONS HAD ON THE COMPANY'S CONSUMPTION OF COAL.

A. 2020 saw an unprecedented loss of demand for electricity due primarily to the COVID-19 global pandemic. This crisis, when combined with historically low natural gas prices, created an environment of exceptionally weak power prices. As a result, the Company's coal-fired electricity generating units were not being

[1] EIA Total Electric Power Industry Summary Statistics, 2020 and 2019; https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_es1a.

[2] *Argus Coal Weekly* Physical Market Assessments.

dispatched as frequently. This caused the Company's actual consumption of coal to be well below the volumes forecasted for period at the time the purchases of coal were made; therefore, any Open Positions that were intended for spot purchases did not materialize. However, 2021 did begin to see a return to higher generation and the consumption of coal was closer to forecasted during the first part of the year.

Q. WHAT EFFECT DID RECENT MARKET CONDITIONS HAVE ON THE PRICE APCO PAID FOR COAL?

A. The recent market had little impact on the purchase price of coal delivered in 2020 as no additional contracts were executed during the period and prices were set prior to entering 2020. Delivered coal prices were 3.9% higher per ton in 2020 than prices paid for coal delivered in 2019. Of this increase, 2.5% was coal related and 1.4% was transportation related. The majority of the coal purchases and the pricing for such purchases were negotiated prior to the calendar year, either as a mechanism in a long-term agreement, or through use of APCo's strategy of layering purchases over time to fill open positions.

Both American Consolidated Natural Resources, the former Murray Energy Corporation and Blackhawk Coal Sales, LLC emerged from bankruptcy. Both companies continued to fulfill their obligations to supply coal under their associated agreements.

IV. COAL DELIVERY FORECAST

Q. HAS AEPSC PREPARED A FORECAST OF DELIVERED COAL COSTS FOR APCO'S POWER PLANTS FOR THE PERIOD NOVEMBER 2021 THROUGH OCTOBER 2022?

A. Yes. Data, prepared as of June 2021, by coal purchase type (Committed, Non-Committed, and Total) and price per ton (FOB mine), Transportation, and Total Delivered Cost, along with the total weighted average forecasted cost of coal delivered to APCo's generating stations, on a cents per million British Thermal Units (¢/MMBTU) basis, for the period November 2021 through October 2022, was provided to Company witness Sloan for use in preparing APCo's forecast.

This forecast estimates total costs of delivered coal (on a total company weighted average basis) to APCo's plants, over the period of November 2021 through October 2022, of $45.59 per ton, or 184.84 ¢/MMBTU.

Q. IN PREPARING THE FORECAST OF DELIVERED COAL, HAS APCO CHANGED THE METHODOLOGY IT HAS HISTORICALLY USED IN THE DEVELOPMENT OF SUCH FORECASTS?

A. No. The methodology utilized in this forecast is consistent with the methodology that has been used by APCo and presented to this Commission in previous proceedings.

V. PORTFOLIO OF COAL SUPPLY AGREEMENTS

Q. PLEASE DESCRIBE APCO'S PORTFOLIO OF LONG-TERM COAL SUPPLY AGREEMENTS.

A. APCo currently has five long-term contracts, with terms longer than 1 year, that will be in effect as of July 1, 2021. Of the four long-term, high-sulfur contracts, three expire in 2021 and one expires in 2022. Two of the three long-term, low-sulfur contracts expire in 2021, and the other expires in 2022. Summary information regarding these agreements is presented in APCo Exhibit No. ___ (KKC) Schedule 1.

VI. CONCLUSION

Q. ARE APCO'S PROJECTED COAL COSTS REASONABLE?

A. Yes. APCo continues to manage its inventory position, monitor conditions in the coal market and perform regular market solicitations, as necessary, to ensure reliable supplies of coal at the lowest delivered reasonable cost. APCo's projected coal costs, reflecting its committed purchases, are reasonable for use in estimating the total projected fuel costs for the period of November 2021 through October 2022.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APCo Exhibit No. _____
Witness: KKC
Schedule 1
Page 1 of 1

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APPALACHIAN POWER COMPANY
2021 VIRGINIA FUEL FACTOR FILING
SUMMARY OF LONG TERM COAL SUPPLY AGREEMENTS EFFECTIVE AS OF July 1, 2021

					Contracted Quality Specifications			
Supplier	Contract Number	Delivery Start Date	Plant(s)	Transportation Options	BTU (Minimum)	Moisture (Maximum)	Ash (Maximum)	Lbs SO2/ MMBTU (Maximum)
American Energy Corporation	02-10-06-901	1/1/2008	Amos, Mountaineer	Barge	12,200	8.0%	11.0%	7.50
Consolidation Coal Company	02-10-12-900	1/1/2012	Amos, Mountaineer	Barge/Rail	11,800	9.0%	13.0%	7.25
Alliance Coal, LLC	02-10-19-9M1	1/1/2020	Mountaineer	Barge	12,300	9.0%	11.0%	5.60
Alliance Coal, LLC	02-10-19-9M2	1/1/2021	Mountaineer	Barge	12,300	10.0%	12.0%	5.60
Blackhawk Coal Sales, LLC	02-40-18-022	1/1/2020	Amos	Barge	11,800	9.0%	14.0%	1.60
Contura Coal Sales, LLC	02-40-19-9M2	1/1/2020	Amos	Barge	11,750	10.0%	14.0%	1.75
Contura Coal Sales, LLC*	02-40-19-9M5	1/1/2021	Amos	Barge	11,750	10.0%	14.0%	1.75

APCo Exhibit No. ___
Witness: SAS

DIRECT TESTIMONY OF
SHELLI A. SLOAN
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2021-00205

SUMMARY OF DIRECT TESTIMONY OF SHELLI A. SLOAN

In my testimony I,

- Support the total company fuel forecast of Appalachian Power Company.
- Provide the estimate of APCo's total company Net Energy Requirement of 31,852.4 GWh, and includable cost of $592.4 million, to Company witness Keeton for use in determining APCo's proposed Virginia jurisdictional fuel factor for the period November 2021 – October 2022.

APCo Exhibit No. ___
Witness: SAS

DIRECT TESTIMONY OF
SHELLI A. SLOAN
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2021-00205

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Shelli A. Sloan. I am employed by the American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power, Inc. (AEP), in the Corporate Planning and Budgeting organization as Director Financial Support and Special Projects. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor of Science in Business Administration Degree from The Ohio State University in 1991 and a Master of Business Administration from Ashland University in 2002. I was hired by AEPSC in 1998 into the Information Technology organization where I performed multiple roles in the Resource Management group and the Project Management Office. In 2009, I joined Regulatory Services as a Regulatory Consultant supporting fuel filings for all AEP operating companies.

From 2012 through 2017, I was a Regulatory Case Manager, overseeing large and complex regulatory filings for multiple AEP operating companies. In 2018, I was promoted to the position of Director Case Support and Special Projects where I lead a team responsible for Integrated Resource Plan filings, Renewable acquisition filings, and witness support in all AEP jurisdictions. I moved into my current role in 2021.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR FINANCIAL SUPPORT AND SPECIAL PROJECTS?

A. As Director of Financial Support and Special projects, I am responsible for directing all regulatory activities within the forecasting group, managing the overall flow of the financial forecast process, and leading various special projects involving the Finance organization. I assist in the preparation of financial forecasts in conjunction with operating company personnel, variance analyses, regulatory filings, and other ad hoc analysis for the AEP System's utility companies. With respect to this filing, I am responsible for deriving the sources and disposition of energy analysis for the forecast period.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?

A. Yes, I have submitted testimony on behalf of Indiana Michigan Power Company for its Fuel Adjustment Clause filing.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. The purpose of my testimony is to:

- Provide an estimate of APCo's total company net energy requirement and includable cost for July 1, 2020 through October, 2021, (Bridge Period), and for November 1, 2021 through October 31, 2022, (Forecast Period); and
- Provide a description of the methodologies employed in order to arrive at the forecasted net energy requirement and includable cost.

I provided the estimate of APCo's total company net energy requirement of 31,852.4 GWh, and includable cost of $592.4 million, to Company witness Keeton for use in determining APCo's proposed Virginia jurisdictional fuel factor.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. I sponsor an estimate of APCo's net energy requirement and includable cost for the Forecast Period. Specifically, I sponsor:

- The estimate of the total company net energy requirement and includable cost for the Forecast Period (APCo Exhibit No. ___ (SAS) Schedule 1);
- A total company sources and uses of energy statement for the Forecast Period (APCo Exhibit No. ___ (SAS) Schedule 2);
- The projected Virginia sales to ultimate customers for the Forecast Period (APCo Exhibit No. ___ (SAS) Schedule 3);
- A description of the NEC forecasting methodology (APCo Exhibit No. ___ (SAS) Schedule 4); and
- The incremental Cost Calculation for generation purchased from Wind Farms (APCo Exhibit No. ___ (SAS) Schedule 5).

In addition, for the Bridge Period, I sponsor an estimate of the total company net energy requirement and includable cost, a total company sources and uses of energy statement and a projection of Virginia sales to ultimate customers (APCo Exhibit No. ___ (SAS) Schedule 6).

Q. WERE THE DATA AND SCHEDULES YOU SPONSOR PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. The schedules represent the combined efforts of numerous AEP personnel. I have reviewed the data contained in and results reported by the schedules and found them to be based on valid assumptions and representative of APCo's net energy requirement and includable cost.

Q. HAVE THE DATA AND SCHEDULES YOU SPONSOR BEEN PREPARED IN A MANNER CONSISTENT WITH THE LAST FUEL FACTOR CASE THAT WAS FILED?

A. Yes, the data and schedules were prepared consistently with those presented in the Company's last fuel factor case.

Q. ARE THERE ASSUMPTIONS REFLECTED IN THE CURRENT FORECAST THAT WERE NOT REFLECTED IN THE LAST FUEL FACTOR CASE THAT WAS FILED?

A. Yes. This forecast accounts for the impacts on dispatch that result from the Commonwealth's participation in the Regional Greenhouse Gas Initiative (RGGI). This change primarily affects the Company's sole Virginia-domiciled fossil-fuel plant, Clinch River.

Q. WOULD YOU PLEASE DEFINE NET ENERGY REQUIREMENT AND INCLUDABLE COST?

A. Net energy requirement is defined, as in previous filings, as APCo's internal load (sales to ultimate customers, sales to firm wholesale customers, and losses). The includable cost is defined as the energy cost incurred to meet APCo's internal load requirements, including non-incremental wind costs as well as the financial settlement of PJM LSE (load serving entity) transmission losses, financial transmission rights (FTR) revenues, PJM Implicit Congestion Charges, and the off-system sales (OSS) margin credit. The components of the net energy requirement and includable cost are shown on APCo Exhibit No. ___ (SAS) Schedule 1.

APCo meets the energy requirements economically through a combination of its own generating sources and purchased power. Additional detail related to the sources and uses of energy and sales to ultimate customers is shown on APCo Exhibit No. ___ (SAS) Schedule 2 and APCo Exhibit No. ___ (SAS) Schedule 3, respectively.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DESCRIBES THE METHODOLOGY REFERENCED ABOVE?

A. Yes. Please refer to APCo Exhibit No. ___ (SAS) Schedule 4.

Q. PLEASE DESCRIBE THE COMPANY'S WIND GENERATION RESOURCES.

A. The Company has renewable energy purchase agreements (Wind REPAs) with Camp Grove Wind Farm (Camp), Fowler Ridge Wind Farm (Fowler), Beech Ridge Wind Farm (Beech), Grand Ridge Wind Farm (Grand) and Bluff Point Wind Farm (Bluff). Camp, Fowler and Bluff (RPS Farms) have approved incremental cost recovery through the RPS-RAC. Beech and Grand (Non-RPS Farms) do not.

Q. PLEASE DISCUSS HOW YOU HAVE SHOWN THE FORECASTED NON-INCREMENTAL PURCHASED POWER WIND COSTS IN THIS FILING.

A. Since the total contract costs for the wind farms are included in NEC on APCo Exhibit No. ___ (SAS) Schedule 1, lines 4 and 5, the incremental costs of these contracts are removed on APCo Exhibit No. ___ (SAS) Schedule 1, lines 9 and 10, leaving non-incremental costs of these contracts in the fuel filing. The energy from the wind farms is shown on APCo Exhibit No. ___ (SAS) Schedule 1, lines 22 and 23.

Q. PLEASE DISCUSS HOW THE EXCLUDED INCREMENTAL COSTS FOR THE WIND FARMS WERE CALCULATED.

A. As shown on APCo Exhibit No. ___ (SAS) Schedule 5, the incremental costs were calculated consistent with the methodology that was approved by the Commission in Case No. PUE-2016-00042.

APCo Exhibit No. ___ (SAS) Schedule 5, Page 1 of 2, shows the incremental costs for the Non-RPS Farms which were calculated using the current percentage from the June 2021 monthly fuel factor deferral accounting process.

APCo Exhibit No. ___ (SAS) Schedule 5, Page 2 of 2, shows the incremental costs for the RPS Farms which were calculated using the current percentage from the June 2021 monthly fuel factor deferral accounting process.

These non-incremental costs are equal to the replacement costs APCo would have incurred had the wind contracts not been in place.

Q. PLEASE DESCRIBE HOW THE FORECAST OF THE OFF-SYSTEM SALES MARGIN CREDIT WAS DERIVED.

A. OSS volume is a function of APCo's forecasted generation and committed purchases (*i.e.*, OVEC, Summersville hydro, solar and wind) as determined by the *PLEXOS®* simulation model and hour-by-hour internal load. An off-system sale is forecasted to occur during a given hour when the sum of APCo's total forecasted generation and committed purchases is greater than its internal load requirement.

Off-system sales transactions are assumed to be made with parties in the PJM market and priced according to forecasted market prices. The total forecast of OSS revenues is divided between cost recovery and net realization or margin.

These margins consist of both physical and non-physical transactions in the wholesale market. The margin represents the value that remains after subtracting the variable cost incurred to make off-system sales from the total revenue realized. This definition is consistent with how these margins have been defined since off-system sales margins are included as a credit to fuel costs. The incremental transmission line loss margins, FTR Revenues and PJM Implicit Congestion Charges on lines 12, 14 and 15 of APCo Exhibit No. ___ (SAS) Schedule 1 have been adjusted out of the off-system sales margin, and a 75% factor has been applied to the remaining margin.

Q. WHAT IS THE NET ENERGY REQUIREMENT AND INCLUDABLE COST FOR THE FORECAST PERIOD FOR APCO?

A. As shown on APCo Exhibit No. ___ (SAS) Schedule 1, line 28, APCo's net energy requirement is 31,852.4 GWh. APCo Exhibit No. ___ (SAS) Schedule 1, line 16 also shows the total Company Includable Cost is $592.4 million. The estimated per-unit cost is 18.60 mills/kWh (or 1.860 ¢/kWh), before consideration for any line losses. This rate is used as the starting point in the determination of the proposed Virginia jurisdictional fuel factor as developed by Company witness Keeton in this proceeding.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPALACHIAN POWER COMPANY

Projected Net Energy Requirement
and Includable Cost
For the 12 Months Ending October 2022

Line No.	Net Energy Cost ($000)	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	12 Mos. Ending 10/31/2022
1	Fossil Generation (A/C 151)	42,492.0	60,083.1	59,769.6	51,401.2	27,860.8	21,840.6	34,831.0	43,371.6	59,815.1	60,129.1	47,417.7	33,418.0	542,509.9
2	Plus:													
3	Purchases (total cost)	10,643.2	6,758.2	11,621.7	13,042.7	27,317.6	20,316.7	11,666.9	6,677.6	4,845.8	4,058.0	3,514.0	10,433.0	130,895.5
4	Purchase Power Wind Energy - Camp Grove, Fowler Ridge & Bluff Point	4,739.9	5,097.1	5,505.7	4,680.5	4,715.5	4,772.7	3,631.2	2,631.5	1,848.2	1,791.0	2,484.7	4,199.1	46,097.2
5	Purchase Power Wind Energy - Beech Ridge & Grand Ridge	4,704.3	4,883.3	5,738.2	5,537.4	5,350.0	5,109.4	3,654.2	2,850.3	2,080.0	1,879.6	2,499.9	3,749.8	48,034.4
6	Less:													
7	Energy Generated for Off-System Sales (A/C 151)	6,342.5	12,907.0	9,676.6	8,481.8	875.1	108.0	7,579.9	7,834.8	14,157.7	15,224.4	12,079.7	4,920.8	100,188.4
8	Total Net Energy Cost	56,236.9	63,894.8	72,958.6	66,180.0	64,368.8	51,931.5	46,203.4	47,696.2	54,531.4	52,633.3	43,836.7	46,879.1	667,348.5
9	Incremental Wind Excluded from Fuel Filing - Camp Grove, Fowler Ridge & Bluff Point	(1,577.9)	(1,696.8)	(1,832.9)	(1,556.1)	(1,569.8)	(1,588.8)	(1,208.8)	(876.0)	(615.3)	(596.2)	(827.2)	(1,397.9)	(15,345.7)
10	Incremental Wind Excluded from Fuel Filing - Beech Ridge & Grand Ridge	(3,042.4)	(3,158.2)	(3,709.8)	(3,581.2)	(3,460.0)	(3,304.4)	(2,363.3)	(1,843.4)	(1,345.2)	(1,215.6)	(1,616.8)	(2,425.2)	(31,065.6)
11	75% of Off-System Sales Margin Credit	(1,367.2)	(2,953.2)	(2,299.7)	(2,287.9)	34.8	(1,191.3)	(1,909.3)	(1,698.9)	(5,426.4)	(5,023.1)	(3,799.4)	(927.8)	(28,849.3)
12	100% of Incremental Transmission Line Loss Margins	(656.3)	(698.0)	(839.5)	(821.3)	(556.9)	1,382.6	(505.7)	(607.5)	(1,134.8)	(932.9)	(723.1)	(618.1)	(6,711.5)
13	PJM LSE Transmission Losses	1,485.0	1,600.0	1,830.0	1,680.0	1,685.0	1,290.0	1,580.0	1,645.0	1,530.0	1,625.0	1,280.0	1,255.0	18,485.0
14	FTR Revenues	(2,773.9)	(3,344.6)	(3,616.8)	(3,243.8)	(2,933.8)	(2,410.1)	(2,503.1)	(2,773.4)	(3,124.4)	(3,020.7)	(2,580.1)	(2,532.2)	(34,857.0)
15	PJM Implicit Congestion Charges	2,190.0	2,415.0	2,150.0	2,025.0	1,685.0	1,705.0	1,840.0	2,035.0	2,000.0	1,720.0	1,710.0	1,885.0	23,360.0
16	Includable Cost	50,494.1	56,058.9	64,637.9	58,392.7	59,253.0	47,814.5	41,133.1	43,576.9	46,415.3	45,189.8	37,280.2	42,117.9	592,384.4

Line No.	Net Energy Requirement (GWH)	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	12 Mos. Ending 10/31/2022
17	Fossil Generation	2,206.4	3,129.5	3,070.7	2,629.0	1,470.5	1,186.4	1,964.0	2,288.1	3,104.5	3,170.6	2,682.9	1,955.1	28,857.8
18	Hydro Generation	52.8	59.7	68.4	72.5	75.2	82.8	68.2	48.8	27.0	28.1	28.0	33.7	645.3
19	Total Generation	2,259.2	3,189.2	3,139.1	2,701.5	1,545.7	1,269.2	2,032.2	2,336.9	3,131.5	3,198.7	2,711.0	1,988.9	29,503.1
20	Plus:													
21	Purchases	442.5	289.7	410.2	425.7	1,027.8	832.4	542.6	341.9	225.7	188.9	185.2	437.5	5,350.0
22	Purchases - Wind - Camp Grove, Fowler Ridge & Bluff Point	88.0	90.2	94.0	79.6	86.7	85.6	66.4	48.4	32.3	32.3	45.8	76.8	826.1
23	Purchases - Wind - Beech Ridge & Grand Ridge	51.7	49.4	56.6	51.4	58.6	54.9	40.0	30.7	20.4	18.2	28.5	42.6	501.1
24	PJM Marginal Losses	62.2	72.8	78.3	69.1	65.7	54.7	55.2	58.4	68.6	68.1	57.2	56.3	762.6
25	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Less:													
27	Energy Purchased and Generated for Off-System Sales	299.1	649.2	486.4	433.1	40.3	3.7	432.3	391.4	699.2	764.7	849.3	241.8	5,090.4
28	Total Net Energy Requirement	2,604.5	3,042.0	3,291.9	2,894.2	2,744.1	2,293.2	2,304.0	2,425.0	2,777.4	2,739.5	2,376.3	2,360.3	31,852.4
29	Net Energy Cost (m/kwh)	19.39	18.43	19.64	20.18	21.59	20.85	17.85	17.97	16.71	16.50	15.69	17.84	18.60

APCo Exhibit No. ______
Witness: SAS
Schedule 1
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210930023

APPALACHIAN POWER COMPANY
Sources and Uses of Energy
For the 12 Months Ending October 2022
(GWH)

Line No.	Sources of Energy	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	12 Mos. Ending 10/31/2022
	Fossil Generation by Plant:															
	AMOS	1,133.9	1,709.0	1,691.4	1,512.3	978.6	955.5	1,148.5	1,221.2	1,735.7	1,741.4	1,448.7	732.7	509.5	1,303.2	16,008.8
	CEREDO	-	-	18.1	25.2	-	-	-	7.2	71.0	31.7	27.8	-	1.9	-	181.0
	CLINCH RIVER - GAS	-	-	5.0	5.1	-	-	5.3	26.0	71.8	77.3	39.9	39.8	1.5	-	270.2
	DRESDEN	445.4	471.0	479.4	423.8	441.8	231.0	423.3	394.8	406.7	411.8	405.8	331.8	442.9	468.0	4,868.5
	MOUNTAINEER	627.1	949.5	876.9	662.6	50.2	-	386.9	638.8	819.2	908.4	760.7	851.0	830.5	874.8	7,531.3
	Total Fossil Generation	2,206.4	3,129.5	3,070.7	2,629.0	1,470.5	1,186.4	1,964.0	2,288.1	3,104.5	3,170.6	2,682.9	1,955.1	1,786.3	2,643.9	28,857.8
	Hydro Generation	52.8	59.7	68.4	72.5	75.2	82.8	68.2	48.8	27.0	28.1	28.0	33.7	51.1	58.5	645.3
1	Total Generation	2,259.2	3,189.2	3,139.1	2,701.5	1,545.7	1,269.2	2,032.2	2,336.9	3,131.5	3,198.7	2,711.0	1,988.9	1,837.4	2,702.4	29,503.1
2	Purchased Power:															
3	Purchased Power	442.5	289.7	410.2	425.7	1,027.6	832.4	542.6	341.9	225.7	188.9	185.2	437.5	639.9	385.6	5,350.0
4	Purchased Power - Wind - Camp Grove, Fowler Ridge & Bluff Point	88.0	90.2	94.0	79.6	88.7	85.6	66.4	48.4	32.3	32.3	45.8	76.8	88.0	90.2	826.1
5	Purchased Power - Wind - Beech Ridge & Grand Ridge	51.7	49.4	56.6	51.4	58.6	54.9	40.0	30.7	20.4	18.2	26.5	42.6	51.7	49.4	501.1
6	Other *															-
7	Total Purchased Power	582.2	429.2	560.9	556.7	1,173.0	972.9	649.0	421.0	278.5	239.4	257.5	557.0	779.6	525.1	6,677.2
8	PJM Marginal losses	62.2	72.8	78.3	69.1	65.7	54.7	55.2	58.4	66.6	66.1	57.2	58.3	61.9	71.8	762.6
9	Total Sources of Energy	2,903.6	3,691.2	3,778.3	3,327.3	2,784.3	2,296.9	2,736.4	2,816.4	3,476.6	3,504.2	3,025.6	2,602.1	2,678.9	3,299.4	36,942.8
	Uses of Energy															
	Sales of Ultimate Customers:															
10	Residential	886.7	1,264.1	1,421.1	1,150.4	978.1	721.3	675.1	716.1	986.9	902.6	696.9	638.6	879.0	1,239.9	11,037.9
11	Commercial	502.7	482.7	528.5	471.3	474.5	415.2	482.6	488.1	593.3	534.7	468.8	475.5	500.5	474.6	5,918.0
12	Industrial	806.0	713.9	714.8	702.2	752.6	692.7	767.4	731.1	785.4	759.8	729.3	777.0	810.8	714.2	8,932.1
13	All Other Ultimates	75.8	72.0	75.2	71.3	72.0	63.4	70.9	67.2	72.2	68.3	68.9	70.9	77.1	72.6	848.0
14	Total Sales to Ultimates	2,271.2	2,532.7	2,739.6	2,395.2	2,277.2	1,892.5	1,996.0	2,002.5	2,437.8	2,265.4	1,963.9	1,962.0	2,267.4	2,501.2	26,736.0
15	Associated Companies	130.7	159.2	172.4	164.5	146.9	129.9	122.6	127.6	158.3	142.6	125.3	117.1	132.2	160.1	1,695.0
16	Municipals and Cooperatives	85.7	97.4	106.3	93.6	89.7	79.3	83.4	92.3	103.3	102.1	89.8	82.7	85.7	97.4	1,105.5
17	Losses	116.9	252.7	273.6	240.9	230.2	191.4	102.1	202.6	80.0	229.4	197.4	198.6	103.4	250.5	2,315.9
18	Total Internal	2,604.5	3,042.0	3,291.9	2,894.2	2,744.1	2,293.2	2,304.0	2,425.0	2,777.4	2,739.5	2,376.3	2,360.3	2,588.6	3,009.2	31,852.4
19	Off-System Sales	299.1	649.2	486.4	433.1	40.3	3.7	432.3	391.4	699.2	764.7	649.3	241.8	90.3	290.2	5,090.4
20	Total Uses of Energy	2,903.6	3,691.2	3,778.3	3,327.3	2,784.3	2,296.9	2,736.4	2,816.4	3,476.6	3,504.2	3,025.6	2,602.1	2,678.9	3,299.4	36,942.8

* Other represents difference due to rounding.

APCo Exhibit No. ______
Witness: SAS
Schedule 2
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2109300023

APCo Exhibit No. ____
Witness: SAS
Schedule 3
Page 1 of 1

APPALACHIAN POWER COMPANY
Sales to Ultimate Customers - Virginia*
For the 12 Months Ending October 2022
(GWH)

Line No.	Sales to Ultimate Customers	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	12 Mos. Ending 10/31/2022
1	Residential	509.7	711.8	792.7	637.6	548.1	407.5	384.7	403.1	559.4	504.6	399.2	363.9	6,222.4
2	Commercial	245.8	233.9	252.5	227.5	226.4	198.9	231.9	232.8	287.1	255.5	224.2	223.0	2,839.6
3	Industrial	429.9	381.7	374.0	378.9	405.2	385.2	426.2	409.5	431.6	417.3	399.5	416.7	4,855.7
4	Virginia Jurisdictional Sales	1,185.4	1,327.4	1,419.2	1,244.0	1,179.7	991.6	1,042.9	1,045.4	1,278.1	1,177.4	1,022.9	1,003.7	13,917.7
5	All Other Ultimates	72.9	68.9	72.1	68.8	69.4	61.3	68.9	65.4	70.4	66.2	66.6	68.2	819.0
6	Total Sales to Ultimates	1,258.3	1,396.3	1,491.3	1,312.7	1,249.1	1,052.9	1,111.8	1,110.8	1,348.5	1,243.6	1,089.5	1,071.9	14,736.7

*Excludes Choice Customers

APCo Exhibit No. ___
Witness: SAS
Schedule 4

Development of NEC Forecast
In Virginia S.C.C. Case No. PUR-2021-00205

I. Overview

The preparation of Appalachian Power Company's (APCo) Net Energy Cost (NEC) forecast requires a projection of APCo's internal load requirement. The internal load projection was developed by the AEPSC Economic Forecasting Department in conjunction with various groups across the AEP System. The AEP Resource Planning Departments developed the generation and off-system sales forecast.

The internal load forecast reflects an analysis of the economy and the unique factors that influence individual customers or customer classes that APCo serves. A forecast of generation (net energy output) from APCo's generating units and purchased power was developed for the Forecast Period to meet APCo's total system load obligations. APCo's generating units are operated along with the units of the other PJM members, to meet the total PJM load requirements on the most economical basis, based on price offers, subject to transmission limitations. Such operation was simulated in the development of the generation forecast by means of the PLEXOS® simulation model, a production costing computer program developed by Energy Exemplar. The generation forecast is prepared considering the impact of the projected fuel deliveries forecast, planned maintenance and other outages, random forced outages and any forecasted energy purchases.

II. Cost of Fuel Consumed

The cost of fuel consumed is based on the generation forecast and projected fuel deliveries for each of APCo's generating units.

Specifically, the cost of coal consumed for each of APCo's generating units is equal to the tons of coal consumed times the average unit cost of coal in fuel inventory. Since the cost of fuel consumed is developed on a monthly basis, the average cost of coal is defined as the weighted average cost of coal in inventory at the beginning of the month plus the projected fuel deliveries during the month. The tons of coal consumed are computed by *PLEXOS®*.

The cost of fuel consumed for the gas plants is also computed by *PLEXOS®*. The cost of gas consumed is based on the generation forecast and projected gas for each of APCo's gas units. The output of the gas units is multiplied by the expected price of natural gas.

III. Purchased Power

APCo's purchased power forecast includes costs associated with planned purchases under long term agreements and market purchases. In this forecast, the planned purchases are for energy purchased from Summersville hydro, Ohio Valley Electric Corporation, renewable energy including solar and various wind farms. During the Forecast Period, APCo is projected to receive energy from the Camp Grove, Fowler Ridge, Grand Ridge, Beech Ridge and Bluff Point wind farms. Other purchases are assigned, based on cost, to either internal load or off-system sales via economic dispatch.

APCo Exhibit No. _____
Witness: SAS
Schedule 5
Page 1 of 2

APPALACHIAN POWER COMPANY
Incremental/Non-Incremental Cost Calculation for
Non-RPS Farms
Beech Ridge & Grand Ridge Wind Farms

Line	Item	2021
1	Wind Purchase Power Agreement Payments	$ 44,395,328
2	Capacity Value	$ (3,235,477)
3	Energy Value	$ (11,507,454)
4	Off-System Sales (OSS) Margins	$ (940,342)
5	**Incremental Cost** (Sum Ln 1:Ln 4)	$ 28,712,055
6	**Incremental Percent** (Ln 5/Ln1)	**64.67%**
7	**Non-Incremental Cost** (Sum Ln 1-Ln 5)	$ 15,683,273
8	**Non-Incremental Percent** (1-Ln 5)	**35.33%**

Note: All values shown are on an APCo total company basis.

APPALACHIAN POWER COMPANY
Incremental/Non-Incremental Cost Calculation for
RPS Farms
Camp Grove, Fowler Ridge & Bluff Point Wind Farms

Line	Item	2021
1	Wind Purchase Power Agreement Payments	$ 41,219,413
2	Capacity Value	$ (5,427,126)
3	Energy Value	$ (21,018,531)
4	Off-System Sales (OSS) Margins	$ (3,420,686)
5	**Incremental Cost** (Sum Ln 1:Ln 4)	$ 11,353,069
6	**Incremental Percent** (Ln 5/Ln1)	27.54%
7	**Non-Incremental Cost** (Sum Ln 1-Ln 5)	$ 29,866,344
8	**Non-Incremental Percent** (1-Ln 5)	72.46%

Note: All values shown are on an APCo total company basis.

APCo Exhibit No. ____
Witness: SAS
Schedule 6
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APPALACHIAN POWER COMPANY
Projected Net Energy Requirement and Includable Cost
For the period July 2021 - October 2021

Line No.	Net Energy Cost ($000)	Jul 2021	Aug 2021	Sep 2021	Oct 2021
1	Fossil Generation (A/C 151)	56,965.3	54,272.2	34,766.2	16,961.8
2	Plus:				
3	Purchases (total cost)	8,044.1	6,326.3	16,497.2	36,399.6
4	Purchase Power Wind Energy - Camp Grove, Fowler Ridge & Bluff Point	1,809.9	1,778.4	2,420.6	4,094.9
5	Purchase Power Wind Energy - Beech Ridge & Grand Ridge	2,058.9	1,791.9	2,405.9	3,727.3
6	Less:				
7	Energy Generated for Off-System Sales (A/C 151)	9,336.3	8,618.6	4,250.1	311.5
8	Total Net Energy Cost	59,541.9	55,550.2	51,839.9	60,872.1
9	Incremental Wind Excluded from Fuel Filing - Camp Grove, Fowler Ridge & Bluff Point	(602.5)	(592.0)	(805.8)	(1,363.2)
10	Incremental Wind Excluded from Fuel Filing - Beech Ridge & Grand Ridge	(1,331.6)	(1,158.9)	(1,556.0)	(2,410.6)
11	75% of Off-System Sales Margin Credit	(3,323.7)	(2,288.2)	(1,122.8)	97.1
12	100% of Incremental Transmission Line Loss Margins	(1,262.5)	(862.2)	(829.0)	(462.1)
13	PJM LSE Transmission Losses	1,530.0	1,625.0	1,280.0	1,255.0
14	FTR Revenues	(3,029.4)	(2,985.4)	(2,503.7)	(2,449.2)
15	PJM Implicit Congestion Charges	2,000.0	1,720.0	1,710.0	1,885.0
16	Includable Cost	53,522.3	51,008.5	48,012.6	57,424.1

Line No.	Net Energy Requirement (GWH)	Jul 2021	Aug 2021	Sep 2021	Oct 2021
17	Fossil Generation	2,740.4	2,741.7	1,772.9	840.6
18	Hydro Generation	24.3	24.0	24.2	34.4
19	Total Generation	2,764.7	2,765.7	1,797.1	875.0
20	Plus:				
21	Purchases	320.9	256.2	656.4	1,327.2
22	Purchases - Wind - Camp Grove, Fowler Ridge & Bluff Point	32.3	32.3	45.8	76.8
23	Purchases - Wind - Beech Ridge & Grand Ridge	20.4	18.2	26.5	42.6
24	PJM Marginal Losses	67.2	66.0	57.4	56.4
25	Other	-	-	-	-
26	Less:				
27	Energy Purchased and Generated for Off-System Sales	409.9	395.4	201.5	10.8
28	Total Net Energy Requirement	2,795.7	2,743.0	2,381.7	2,367.3
29	Net Energy Cost (m/kwh)	19.14	18.60	20.16	24.26

APPALACHIAN POWER COMPANY
Sources and Uses of Energy
For the period July 2021 - October 2021
(GWH)

Line No.	Sources of Energy	Jul 2021	Aug 2021	Sep 2021	Oct 2021
	Fossil Generation by Plant:				
	AMOS	1,520.2	1,444.6	1,051.8	700.9
	CEREDO	41.1	8.2	27.5	-
	CLINCH RIVER - GAS	66.3	17.0	13.6	-
	DRESDEN	399.9	399.0	402.3	139.7
	MOUNTAINEER	712.9	873.0	277.6	-
1	Total Fossil Generation	2,740.4	2,741.7	1,772.9	840.6
	Hydro Generation	24.3	24.0	24.2	34.4
	Total Generation	2,764.7	2,765.7	1,797.1	875.0
2	Purchased Power:				
3	Purchased Power	320.9	256.2	656.4	1,327.2
4	Purchased Power - Wind - Camp Grove, Fowler Ridge & Bluff Point	32.3	32.3	45.8	76.8
5	Purchased Power - Wind - Beech Ridge & Grand Ridge	20.4	18.2	26.5	42.6
6	Other *	-	-	-	-
7	Total Purchased Power	373.7	306.7	728.7	1,446.7
8	PJM Marginal losses	67.2	66.0	57.4	56.4
9	Total Sources of Energy	3,205.6	3,138.4	2,583.2	2,378.1
	Uses of Energy				
	Sales of Ultimate Customers:				
10	Residential	973.6	914.1	728.7	655.7
11	Commercial	578.5	536.6	483.7	485.1
12	Industrial	763.6	751.7	731.0	776.5
13	All Other Ultimates	69.1	67.1	69.2	70.7
14	Total Sales to Ultimates	2,384.8	2,269.6	2,012.5	1,988.0
15	Associated Companies	155.4	140.7	123.5	115.4
16	Municipals and Cooperatives	103.2	102.0	89.7	82.7
17	Losses	152.4	230.7	156.1	181.3
18	Total Internal	2,795.7	2,743.0	2,381.7	2,367.3
19	Off-System Sales	409.9	395.4	201.5	10.8
20	Total Uses of Energy	3,205.6	3,138.4	2,583.2	2,378.1

* Other represents difference due to rounding.

2160300223

APCo Exhibit No. _____
Witness: SAS
Schedule 6
Page 3 of 3

APPALACHIAN POWER COMPANY
Sales to Ultimate Customers - Virginia*
For the period July 2021 - October 2021
(GWH)

Line No.	Sales to Ultimate Customers	Jul 2021	Aug 2021	Sep 2021	Oct 2021
1	Residential	548.5	508.0	414.3	371.4
2	Commercial	280.6	257.4	232.6	228.7
3	Industrial	419.8	412.5	400.1	415.9
4	Virginia Jurisdictional Sales	1,249.0	1,177.8	1,047.0	1,016.0
5	All Other Ultimates	67.2	65.1	66.9	67.9
6	Total Sales to Ultimates	1,316.2	1,242.9	1,114.0	1,083.9

*Excludes Choice Customers

APCo Exhibit No. ___
Witness: CMS

**DIRECT TESTIMONY OF
CLINTON M. STUTLER
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2021-00205**

APCo Exhibit No. ___
Witness: CMS

SUMMARY OF DIRECT TESTIMONY OF CLINTON M. STUTLER

My direct testimony discusses the three natural gas-fired power plants owned and operated by Appalachian Power Company (APCo or Company), explains the impact that prices in the natural gas market have had on the Company, and discusses the Company's natural gas procurement strategy, including the Company's natural gas supply and transportation agreements. These elements support the conclusion that the forecast for natural gas delivery, as provided for the twelve-month period from November 1, 2021 through October 31, 2022 is reasonable.

APCo Exhibit No. ___
Witness: CMS

DIRECT TESTIMONY OF
CLINTON M. STUTLER
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2021-00205

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Clinton M. Stutler, and I am employed by American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP) in the regulated Commercial Operations organization as the Natural Gas and Fuel Oil Manager. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Master's degree in Business Administration from Bowling Green State University in 2007, and a Bachelor of Science in Business Administration degree, with a major in Transportation & Logistics and Marketing, from The Ohio State University in 2002.

I have over nineteen years of energy–industry experience in fuel procurement, logistics, marketing, scheduling, and transportation. My professional background began in 2002 as a Scheduler with Marathon Petroleum Company. In 2008, I joined AEPSC in the Fuel, Emissions, and Logistics organization as a Coal Buyer, with responsibilities for the procurement of coal for Ohio Power Company. In 2014, I joined AEP Generation Resources, with responsibilities for purchasing natural gas, coal, urea, and fuel oil, in addition to marketing fly ash and flue gas desulfurization gypsum. In 2016, I accepted a position in the regulated Commercial Operations organization as a Coal Buyer and became responsible for the procurement of coal for APCo, Kentucky Power Company (KPCo), and Southwestern Electric Power Company (SWEPCO). On May 4, 2018, I was promoted to my current position and became responsible for the procurement and delivery of natural gas and fuel oil to AEP's regulated generating fleet.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS NATURAL GAS AND FUEL OIL MANAGER FOR AEPSC?

A. As the Natural Gas and Fuel Oil Manager, I am responsible for the natural gas and fuel oil procurement and contract management of AEP's regulated operating companies, including APCo, Indiana & Michigan Power Company (I&M), KPCo, SWEPCO, and Public Service Company of Oklahoma (PSO).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AGENCIES?

A. Yes. I have submitted written testimony to the Virginia State Corporation Commission on behalf of APCo. Furthermore, I have filed written testimony before the Public Service Commission of West Virginia, on behalf of APCo and Wheeling Power Company, before the Public Service Commission of Kentucky on behalf of KPCo, before the Public Utility Commission of Texas on behalf of SWEPCO and before the Oklahoma Corporation Commission on behalf of PSO.

PURPOSE

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

A. The purpose of my testimony in this proceeding is to:

1) Provide a general description of APCo's natural gas-fired plants;

2) Provide an overview of the natural gas market in which APCo procures gas;

3) Describe the natural gas delivery forecast for the twelve-month period from November 1, 2021 through October 31, 2022 (Forecast Period); and

4) Discuss APCo's natural gas procurement strategy and APCo's natural gas transportation agreements.

NATURAL GAS-FIRED PLANTS

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE NATURAL GAS-FIRED PLANTS INCLUDED IN APCO'S GENERATING FLEET.

A. APCo currently has three natural gas-fired plants in its generating fleet, including the Clinch River Plant (Clinch River), the Dresden Plant (Dresden), and the Ceredo Plant (Ceredo).

Clinch River is a two-unit natural gas-fired generating facility located in Russell County, Virginia with a combined nominal capacity rating for Units 1 and 2 of 465 Megawatts (MW) (Unit 1 is 230 MW and Unit 2 is 235 MW). The coal-to-gas conversion of Unit 1 was completed in March of 2016 and the coal-to-gas conversion of Unit 2 was completed in April of 2016. Clinch River, which typically operates during periods of peak demand, receives its fuel supply from a natural gas pipeline constructed by Appalachian Natural Gas Distribution Company (ANGDC), a Virginia corporation.

Dresden, a 611 MW baseload natural gas-fired combined-cycle facility, which began commercial operation on January 31, 2012, is located near the Muskingum River in Dresden, Ohio. Dresden is a "2-on-1" combined-cycle plant, meaning it is equipped with two gas turbines and two heat recovery steam generators. The steam from these generators then feed one steam turbine to provide additional electricity.

Combined-cycle plants generate more efficiently and consume less fuel per kilowatt-hour of output than conventional simple-cycle plants.

Ceredo, a 516 MW, natural gas-fired simple-cycle power plant, which began commercial operation in 2001, is located near Ceredo, West Virginia. With a natural gas simple-cycle power plant, natural gas powers a combustion turbine, which is connected directly to a generator that produces electricity. Ceredo ramps up quickly, operates as a peaking plant and is utilized when electricity demand is high.

MARKET OVERVIEW

Q. PLEASE DESCRIBE RECENT AND EXPECTED CHANGES IN THE NATURAL GAS MARKET.

A. The first two months of 2020 were characterized by relatively mild weather, which allowed natural gas storage to remain healthy. This put the market at ease, as the most significant days for heating demand were passed. In March and April of 2020, when COVID-19 suspended operation at many businesses, there became a noticeable decrease in natural gas demand. Additionally, as this was a global pandemic, the lack of demand for liquefied natural gas (LNG) exports further contributed to a domestic supply and demand imbalance. This imbalance caused prices to decrease, which influenced production to come offline. During the first quarter of 2020, natural gas production was about 3.5 Bcf per day lower than the record peak, which occurred in November of 2019. As the summer months approached, natural gas production continued to decline. The U.S. natural gas rig count bottomed out at 68 working rigs during the month of July 2020, which was down 106 working rigs from a year earlier.

As the end of the 2020 summer drew near, the market became somewhat apprehensive regarding the lack of natural gas production. Many were of the opinion that a resurgence of export demand and normal winter weather could create a rather tight market in the subsequent months. In response, the New York Mercantile Exchange (NYMEX) forward curve started to become stronger, and surged past the $3.00 per MMBtu mark for the upcoming winter months. A mild October and November of 2020 moderated forward prices, however, as the global economy began to recover, LNG demand was robust for the entire month of December 2020. This robust demand continued into 2021.

U.S. natural gas storage began 2021 at a surplus when compared to the five-year-average. However, with natural gas production continuing to lag, coupled with increased demand, aggressive withdrawals from storage began to erode the storage surplus. By the end of February 2021, U.S. natural gas storage was at a deficit when compared to the five-year-average. Even with a few price spikes due to cold weather demand, as well as several massive storage withdrawals, prompt month forward prices remained relatively low throughout the winter and spring, staying under $3.00 per MMBtu.

With modest production growth, strong demand and the recognition that the supply and demand balance will remain tight for the foreseeable future, the prompt month NYMEX settled at $3.617 per MMBtu for the month of July 2021. This was the highest prompt month settle price since December of 2018. As we've now moved through July and part of August 2021, still experiencing strong demand and weak storage injections, the forward curve is indicating pricing around or above the $4.00 per MMBtu mark through February of 2022.

Q. WHAT EFFECT DID RECENT NATURAL GAS MARKET CONDITIONS HAVE ON THE OPERATION OF APCO'S NATURAL GAS PLANTS?

A. While total U.S. domestic production has been down, production in the Appalachian Basin has remained strong. Based on data published by the U.S. Energy Information Administration (EIA), natural gas production in the Appalachian Basin, averaged approximately 33.7 billion cubic feet (Bcf) per day in 2020. This equates to an increase of 1.5 Bcf per day, when compared to 2019. With continued, increased production and limited outlets, prices were depressed throughout most of calendar year 2020. As mentioned in the previous section, natural gas prices have been on the rise in 2021. However, due to the continued strong production in the Appalachian Basin, APCo's plants have been somewhat insulated from the full impact of such price increases. This is particularly true for Dresden, as this plant still benefits from a large basis discount to Henry Hub trading point.

Natural gas purchased for Dresden was procured at the Eastern Gas, South receipt point, which is located in a shale-rich area on the Eastern Gas Transmission & Storage (EGTS) pipeline. Dresden has continued to operate as a baseload plant consuming 31.5 million MMBtus in 2020 and 15.5 million MMBtus during the first half of 2021. This compares to approximately 30.2 million MMBtus during calendar year 2019 and 15.7 million MMBtus in the first half of 2020.

Ceredo consumed approximately 1.4 million MMBtus in 2020, which is less than half of what was consumed in 2019. For the first half of 2021, Ceredo has consumed approximately 1.4 million MMBtus, which is an increase compared to consumption of less than 0.2 million MMBtus during the first half of 2020.

Clinch River is located farther southeast and is unable to directly benefit from inexpensive Marcellus shale gas due to the plants proximity to higher demand markets and population centers. Clinch River's consumption totaled approximately 3.3 million MMBtus in 2020, which is less than the 2019 total of approximately 4.0 million MMBtus. During the first half of 2021, Clinch River was essentially flat in consumption when compared to the first half of 2020, with the plant consuming just under 0.7 million MMBtus, as compared to approximately 0.8 million MMBtus during the first half of 2020.

NATURAL GAS DELIVERY FORECAST

Q. HAS AEPSC PREPARED A FORECAST OF DELIVERED NATURAL GAS COSTS FOR APCO'S POWER PLANTS FOR THE FORECAST PERIOD?

A. Yes. Data was prepared during the second quarter of 2020 using the *PLEXOS*® simulation model, and was used by Company witness Sloan in preparing APCo's forecast. This forecast estimates total costs of delivered natural gas (on a total company weighted average basis) to APCo's plants, over the Forecast Period, of approximately 38.8 million MMBtus at approximately $2.39 per MMBtu.

NATURAL GAS PROCUREMENT STRATEGYAND TRANSPORTATION AGREEMENTS

Q. PLEASE DESCRIBE APCO'S NATURAL GAS PROCUREMENT STRATEGY.

A. APCo's natural gas procurement strategy provides reliable fuel at the lowest reasonable delivered cost for its customers. The procurement strategy is based on two components: transportation and supply. Natural gas pipeline transportation agreements secure the necessary means to transfer the gas supply from the source to the plant. Gas supply agreements provide the commodity used to fuel the power plant. In order to meet day ahead and real time PJM dispatch requests, APCo needs instantaneous, hourly, and daily flexibility in the delivery flow of natural gas supply. Due to these fluctuating requirements, APCo relies on both firm and interruptible transportation agreements as well as daily spot market natural gas purchases. Additionally, at times when APCo expects Dresden to be available nearly every day of the month, APCo will issue requests for proposals to obtain monthly baseload natural gas supply. APCo's supply, whether daily or baseload, is typically priced using index-based agreements. However, fixed-price agreements are also used on occasion. The natural gas arrangements utilized by APCo provide the required flexibility necessary to reliably operate APCo's system, while minimizing overall total fuel costs.

Q. WHAT ARE THE PRACTICES USED TO PURCHASE NATURAL GAS SUPPLIES FOR APCO?

A. AEPSC, on behalf of APCo, pursues spot market purchase opportunities through a competitive bidding program. For daily market purchases, the natural gas buyer receives a forecast from AEPSC's Bid, Offer and Cost Development team each morning and discusses the expected operation and estimated natural gas requirements for APCo's power plants for the current and the following six days. Then, the natural gas buyer gathers market information from the various natural gas market areas and hubs accessible to APCo. The buyer also obtains pricing and volume information from numerous natural gas suppliers as well as real-time natural gas market data from platforms such as the Intercontinental Exchange (ICE) to locate and optimize purchases in the spot natural gas market.

Once the buyer analyzes the relevant information, the necessary spot natural gas supplies are purchased from the most economical and reliable sources available at the time. The natural gas buyer then makes the necessary nominations and scheduling arrangements with the transporting pipelines to deliver the natural gas supplies to the power plants, and monitors deliveries for each particular gas day. Every afternoon, the natural gas buyer reviews the units that received a day-ahead award from PJM and, depending on results, makes adjustments through additional purchases or sales, as necessary.

For the months that Dresden is expected to operate daily, the natural gas buyer evaluates the need for monthly baseload purchases. The quantity committed under baseload agreements varies depending on projected consumption, weather, anticipated demand, and other factors, but when pursued typically represent twenty percent of expected consumption. Monthly baseload purchases reduce exposure to potential volatility in the daily natural gas market.

Q. PLEASE DESCRIBE APCO'S NATURAL GAS TRANSPORTATION AGREEMENTS.

A. Clinch River has an Interruptible Transportation (IT) agreement with East Tennessee Natural Gas, LLC (ETNG), which was executed in 2015. The agreement provides for deliveries of a Maximum Daily Quantity of 125,000 MMBtus per day to the Clinch River meter at the interconnection of the lateral owned and operated by ANGDC. In order to manage supply imbalances, APCo has a tariff-based balancing agreement in place with ETNG, which is also referred to as Load Management (Market Area) Service agreement (LMS-MA). The LMS-MA agreement allows APCo to carry small daily variances on the pipeline throughout the month. At the end of each month, any long or short imbalance is settled with the pipeline at a pre-determined rate as established by ETNG's tariff. Additionally, APCo has a ten-year Firm Transportation (FT) agreement with ANGDC to move the needed supplies from the ETNG interconnect to Clinch River.

APCO has a ten-year FT agreement with EGTS, executed in 2012, which continues to provide reliable natural gas deliveries to the Dresden Plant with an MDQ of 109,000 MMBtus per day. The original terms of this agreement expire on January 31, 2022. In August of 2020, APCO and EGTS were successful in negotiating a contract extension with revised terms that goes through December 31, 2028.

With regard to Ceredo, APCo has an IT agreement with Columbia Gas Transmission and an FT agreement with Mountaineer Gas Company (MGC), the local distribution company. The FT agreement reliably moves needed supplies from the Columbia Gas Transmission pipeline to the plant. This FT agreement also provides flexible banking services allowing the Ceredo units to meet PJM's requests to come online and offline with little notice.

Q. IS RISK ASSESSMENT AN IMPORTANT FACTOR IN NATURAL GAS PROCUREMENT DECISIONS?

A. Yes. APCo considers a supplier's financial status, ability to deliver, and past performance when evaluating fuel purchase alternatives. This practice is designed to lower the risk and enhance APCo's supply security. Natural gas supplies are only procured from counterparties on APCo's credit approved list

<u>CONCLUSION</u>

Q. ARE APCO'S PROJECTED GAS COSTS REASONABLE?

A. Yes. APCo's projected delivered natural gas costs are reasonable for use in estimating the projected fuel costs for the Forecast Period.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APCo Exhibit No. ___
Witness: EKK

DIRECT TESTIMONY OF
ELEANOR K. KEETON
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2021-00205

APCo Exhibit No. ___
Witness: EKK

SUMMARY OF DIRECT TESTIMONY OF ELEANOR K. KEETON

My direct testimony supports a proposed, increased fuel factor of 2.300¢/kWh to become effective November 1, 2021. In support of this proposal, I provide the estimated under-recovered fuel balance of approximately $38.8 million as of October 31, 2021, the calculations for the new proposed fuel factor, and the projected fuel balance using the proposed fuel factor as of October 31, 2022.

APCo Exhibit No. ___
Witness: EKK

DIRECT TESTIMONY OF ELEANOR K. KEETON FOR APPALACHIAN POWER COMPANY IN VIRGINIA S.C.C. CASE NO. PUR-2021-00205

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Eleanor K. Keeton. My business address is Three James Center, Suite 1100, 1051 East Cary Street Richmond, Virginia 23219. I am employed by Appalachian Power Company (APCo or the Company) as a Regulatory Consultant Principal VA/TN.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received my Master of Public Administration from Virginia Commonwealth University in 2015, with a concentration in Public Policy. From 2013 to 2015 I worked as a graduate research fellow at the Virginia Department of Corrections where my primary responsibilities were to support operations of the Research Unit, including data extraction, collection, and collation for federal grant reporting purposes and compliance to agency procedure. In 2015 I was hired by the Virginia Department of Corrections as a Senior Research Analyst in the Program Fidelity and Evaluation Unit. My primary duties included designing and maintaining various research studies for program evaluation and policy analysis, and making recommendations based on the outcomes of the analyses. In August 2017, I accepted the position of Regulatory Consultant Senior with APCo.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have presented testimony on behalf of APCo before the Virginia State Corporation Commission (Commission or SCC) in Case Nos. PUR-2017-00160, PUR-2018-00043, PUR-2019-00067, PUR-2019-00056, and PUR-2020-00015.

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

A. The purpose of my testimony is to support the Company's proposed fuel factor to be effective November 1, 2021. In that regard, I am sponsoring the following exhibits:

- APCo's actual total company fuel cost by month for the period July 2020 through June 2021 and the booking estimate of total company fuel cost for the month of July 2021 (APCo Exhibit No. __ (EKK) Schedule 1);
- APCo's Virginia jurisdictional fuel cost recovery position projected as of October 31, 2021 (APCo Exhibit No. __ (EKK) Schedule 2);
- Development of the Virginia jurisdictional fuel factor (APCo Exhibit No. ___ (EKK) Schedule 3) to be effective November 1, 2021;
- The projected Virginia jurisdictional fuel cost recovery position as of October 31, 2022, assuming implementation of the proposed fuel factor (APCo Exhibit No. ___ (EKK) Schedule 4) for service rendered beginning November 1, 2021;
- Revision of Virginia SCC Tariff No. 26 Schedule F.F.R. (Fuel Factor Rider) to incorporate the Company's proposed fuel factor effective November 1, 2021 (APCo Exhibit No. __ (EKK) Schedule 5);
- Schedules summarizing the estimated total revenue change associated with the proposed fuel factor change broken down into in-period and true-up components (APCo Exhibit No. ___ (EKK) Schedule 6); and
- A sample billing analysis indicating the effects of the change in the proposed fuel factor on typical customers' monthly bills (APCo Exhibit No. __ (EKK) Schedule 7).

Q. WHAT IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company is proposing that its current fuel factor of 1.999¢/kWh, which was placed in effect November 1, 2020, be increased to 2.300¢/kWh as shown in APCo Exhibit No. ___ (EKK) Schedule 3. The Company is requesting that its proposed fuel factor become effective November 1, 2021.

I. <u>ACTUAL FUEL COST</u>

Q. HAVE YOU DEVELOPED A SCHEDULE THAT PRESENTS THE ACTUAL MONTHLY FUEL COST FOR THE PERIOD JULY 2020 THROUGH JUNE 2021?

A. Yes. APCo Exhibit No. __ (EKK) Schedule 1 displays the actual total Company fuel cost by month for the period July 2020 through June 2021 and for July 2021 based on the Company's booking estimate.

Q. WHY DOES THE ACTUAL FUEL COST DATA PRESENTATION START WITH THE JULY 2020 VALUES?

A. In the Company's most recent fuel filing the most current actual fuel cost data presented by the Company was for June 2020. In this proceeding, the actual fuel cost data presentation begins with July 2020 in order to provide an uninterrupted series of actual cost data.

II. <u>PROJECTED FUEL COST RECOVERY POSITION AS OF OCT. 31, 2021</u>

Q. WHAT IS THE COMPANY'S VIRGINIA JURISDICTIONAL FUEL COST RECOVERY POSITION EXPECTED TO BE AS OF OCTOBER 31, 2021?

A. APCo Exhibit No. __ (EKK) Schedule 2 summarizes the Company's cumulative Virginia jurisdictional fuel cost recovery position, beginning with the June 30, 2020 actual cumulative fuel cost recovery balance; continuing on a monthly basis with actual values from July 2020 through June 2021 and the booking estimate for July 2021; and from August 2021 through October 2021 on a projected basis (using projected monthly fuel cost and energy sales data sponsored by Company witness Sloan in this proceeding). As can be observed from APCo Exhibit No. __ (EKK) Schedule 2, APCo is expected to have a Virginia jurisdictional cumulative fuel cost under-recovery of approximately $38.8 million as of October 31, 2021.

III. PROPOSED FUEL FACTOR

Q. WHAT IS THE COMPANY'S REQUEST REGARDING THE LEVEL OF THE FUEL FACTOR AND THE EFFECTIVE DATE OF CHANGE IN THE CURRENT FACTOR?

A. As previously stated, the Company is presenting evidence that supports a fuel factor of 2.300¢/kWh and requests that the Commission approve this proposed factor to become effective for service rendered on and after November 1, 2021.

Q. PLEASE BRIEFLY DESCRIBE HOW THE PROPOSED FUEL FACTOR WAS DEVELOPED.

A. APCo Exhibit No. __ (EKK) Schedule 3 demonstrates the development of the two components constituting the proposed fuel factor.

The first, or in-period, component (APCo Exhibit No. __ (EKK) Schedule 3, Line 3) of the proposed fuel factor is designed to recover the Virginia jurisdictional fuel cost projected to be experienced during the period November 1, 2021 through October 31, 2022. To obtain the in-period component, the projected fuel cost allocated to the Virginia jurisdiction (APCo Exhibit No. __ (EKK) Schedule 3, Line 1) of $281,296,848, which includes the non-incremental costs associated with APCo's wind contracts, a credit for 75% of projected Off System Sales (OSS) margins, PJM Load Serving Entity (LSE) transmission losses, PJM congestion charges, 100% of incremental transmission line loss margins, and Financial Transmission Right revenues, was divided by the projected Virginia jurisdictional energy sales for the 12 month period of 13,917,703,000 kWh (APCo Exhibit No. __ (EKK) Schedule 3, Line 2). The resulting in-period fuel cost recovery component is 2.021¢/kWh.

The second component (APCo Exhibit No. __ (EKK) Schedule 3, Line 6) of the proposed fuel factor is a true-up component designed to recover from customers over the projected 12 month period, an estimated under-recovered deferred fuel balance as of October 31, 2021 of $38,777,091 as determined in APCo Exhibit No. __ (EKK) Schedule 2. The projected deferred fuel cost balance was divided by the projected Virginia jurisdictional energy sales for the period November 1, 2021 - October 31, 2022 to obtain the prior period under-recovery component of 0.279¢/kWh.

The combination of these two components (APCo Exhibit No. __ (EKK) Schedule 3, Line 7) produces the proposed fuel factor of 2.300¢/kWh.

IV. <u>PROJECTED FUEL COST RECOVERY POSITION AS OF OCTOBER 31, 2022</u>

Q. HAVE YOU PREPARED A SCHEDULE SUMMARIZING THE PROJECTED FUEL COST RECOVERY POSITION AS OF OCTOBER 31, 2022?

A. Yes, APCo Exhibit No. __ (EKK) Schedule 4 summarizes the projected Virginia jurisdictional fuel cost recovery position on a monthly and cumulative basis through October 31, 2022, based upon projected fuel cost and energy sales data sponsored by Company witness Sloan in this proceeding, and using the proposed fuel factor of 2.300¢/kWh developed in APCo Exhibit No. __ (EKK) Schedule 3. APCo Exhibit No. ___ (EKK) Schedule 4 shows that the use of this proposed factor is expected to result in a projected fuel cost over-recovery position of $30,230 as of October 31, 2022.

V. <u>REVISED TARIFF</u>

Q. PLEASE DESCRIBE HOW THE PROPOSED FUEL FACTOR WOULD BE INCORPORATED IN THE COMPANY'S TARIFF.

A. The proposed fuel factor would be shown on tariff Sheet No. 52 entitled "Rider F.F.R." APCo Exhibit No. __ (EKK) Schedule 5 illustrates how the proposed fuel factor would be incorporated in the tariff schedule in the Company's Virginia SCC Tariff No. 26, to be effective with service rendered on and after November 1, 2021.

VI. <u>REVENUE AND BILL IMPACTS</u>

Q. WHAT IS THE NET REVENUE IMPACT OF IMPLEMENTING THE COMPANY'S PROPOSED FUEL FACTOR?

A. APCo Exhibit No. __ (EKK) Schedule 6 shows the components of the Virginia jurisdictional 12-month net revenue impact using the Company's proposed fuel factor, which produces an estimated annual revenue net increase of $41,892,286.

Q. WHAT IS THE IMPACT OF IMPLEMENTATION OF THE PROPOSED FUEL FACTOR ON THE MONTHLY BILLS OF THE COMPANY'S VIRGINIA RETAIL CUSTOMERS?

A. APCo Exhibit No. ___ (EKK) Schedule 7 shows the effects of implementation of the proposed fuel factor on selected residential, commercial and industrial customers' typical monthly bills on and after November 1, 2021. For example, billing under the proposed fuel factor, as contained in APCo Exhibit No. __ (EKK) Schedule 5, would result in a Virginia residential customer of Appalachian Power who uses 1,000 kWh/month experiencing a \$3.01, or 2.6% increase in his monthly bill from \$117.31 to \$120.32.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APCo Exhibit No. ____
Witness: EKK
Schedule 1

210930023

APPALACHIAN POWER COMPANY
TOTAL COMPANY FUEL COST- ACTUAL
JULY 2020 - JUNE 2021

Line No.		(A) July 2020	(A) August 2020	(A) September 2020	(A) October 2020	(A) November 2020	(A) December 2020	(A) January 2021	(A) February 2021	(A) March 2021	(A) April 2021	(A) May 2021	(A) June 2021
	Fuel-related Expense ($)												
1	Generation Expense*	45,969,555	50,942,106	35,384,492	22,761,152	18,401,283	31,807,435	52,120,898	61,910,682	28,896,195	23,564,960	46,079,271	58,339,295
	Plus:												
2	Purchases (total cost)	16,590,021	12,265,957	11,890,080	19,294,548	21,868,341	30,268,023	14,015,888	9,940,767	20,102,679	26,959,068	11,303,996	6,791,993
3	Purchased Wind Energy - Camp Grove/Fowler Ridge/Bluff Point	755,324	708,099	1,316,810	1,996,077	2,495,833	2,328,424	1,955,690	2,125,790	2,416,270	1,773,672	2,029,680	1,806,337
4	Purchased Wind Energy - Beech Ridge & Grand Ridge	453,153	452,811	764,133	1,186,033	1,530,282	1,445,550	1,213,190	1,177,687	1,641,960	1,364,338	962,331	687,472
	Less:												
5	Energy Generated for Off-System Sales (A/C 151)	7,386,869	12,446,831	5,173,798	1,333,465	1,841,950	1,790,403	5,515,567	12,420,333	1,839,798	3,903,486	11,970,032	14,796,973
6	Total Net Energy Cost	56,381,184	51,922,143	44,181,717	43,904,346	44,453,789	64,059,029	63,790,099	62,734,593	51,217,307	49,758,552	48,405,245	52,828,124
7	Incremental Wind Excluded from Fuel Filing - Camp Grove & Fowler Ridge	(699,740)	(655,991)	(1,219,907)	(1,849,188)	(2,312,168)	(2,403,184)	(2,018,482)	(2,194,043)	(2,493,850)	(1,830,619)	(1,012,862)	(901,408)
8	Incremental Wind Excluded from Fuel Filing - Beech Ridge & Grand Ridge	(1,064,948)	(1,064,144)	(1,795,776)	(2,787,277)	(3,596,290)	(3,717,129)	(3,119,631)	(3,028,339)	(4,222,184)	(3,508,299)	(1,852,325)	(1,323,268)
9	Coal Liquidations Margins	0	0	0	0	0	0	0	0	0	0	0	0
10	75% of Off-System Sales Margin Credit	(553,228)	(1,937,564)	(118,162)	(105,104)	(95,495)	(139,456)	(1,215,486)	(4,594,326)	(138,149)	(31,903)	(850,146)	(2,780,586)
11	PJM LSE Transmission Losses	881,736	984,987	568,268	372,661	383,240	1,058,621	1,675,491	2,568,887	805,024	1,042,770	1,786,836	1,623,607
12	100% of Incremental Transmission Line Loss Margins	(210,436)	(287,688)	(7,372)	420,450	630,456	(194,135)	(50,822)	(1,722,621)	723,200	107,392	(165,981)	(464,018)
13	FTR Revenues	(277,625)	(453,913)	(1,238,907)	(1,226,142)	(1,629,003)	(2,672,981)	(1,471,591)	(2,513,019)	(3,002,516)	(3,974,529)	(3,316,913)	(1,979,259)
14	PJM Implicit Congestion Charges	1,206,350	867,512	1,173,544	1,620,837	1,666,246	2,400,840	1,711,933	2,787,999	2,598,334	3,543,504	1,988,279	809,607
15	Includable Cost	57,427,982	51,095,477	44,559,087	44,987,049	45,409,234	64,511,918	64,439,625	59,261,512	52,203,201	50,445,786	47,847,319	50,037,475
	Energy (MWH)												
16	Fossil Generation	2,367,997	2,584,900	1,789,487	1,167,780	1,064,298	1,622,108	2,590,075	2,754,331	1,493,717	1,144,383	2,194,756	2,765,052
17	Hydro Generation	26,261	33,375	35,115	54,691	82,152	84,318	72,328	83,420	81,261	71,751	42,553	34,038
18	Total Generation	2,394,259	2,618,275	1,824,602	1,222,471	1,146,451	1,706,426	2,662,403	2,837,751	1,574,978	1,216,134	2,237,309	2,799,090
	Plus:												
19	Purchases	717,183	571,957	604,593	931,715	1,147,738	1,244,146	621,364	378,395	853,916	1,026,961	431,982	272,266
20	Purchases - Wind - Camp Grove/Fowler Ridge/Bluff Point	26,948	26,407	49,985	72,632	94,222	87,092	69,999	76,787	92,618	70,397	56,818	52,185
21	Purchases - Wind - Beech Ridge & Grand Ridge	15,896	17,056	29,740	44,956	60,100	49,729	44,633	41,018	63,970	51,524	32,425	22,632
22	Purchases - Solar	0	0	0	0	0	0	0	0	0	0	0	(15)
	Less:												
23	Energy Purchases and Generated for Off-System Sales	303,447	576,597	241,487	55,428	82,086	66,904	243,475	465,257	75,639	129,865	512,777	686,081
24	Total Net Energy Requirement	2,850,839	2,657,097	2,267,433	2,216,345	2,366,423	3,020,489	3,154,924	2,868,693	2,509,843	2,235,151	2,245,757	2,460,091
25	Net Energy Cost (Mills/KWH)	20.14	19.23	19.65	20.30	19.19	21.36	20.43	20.66	20.80	22.57	21.31	20.34

(*) Excludes demurrage expense
(A) Actual
(E) Booking Estimate

APCo Exhibit No. __
Witness: EKK
Schedule 2

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
PROJECTED FUEL COST RECOVERY POSITION
AS OF OCTOBER 2021

	Virginia Jurisdictional Energy Sales	Fuel Factor Recovery (a)	Total Company Fuel Cost (b)	Energy Allocation Factor (c)	Virginia Retail Fuel Cost Col. (3) x Col. (4)	Monthly NEC Over (Under) Recovery Col. (2)- (5)	Cumulative Fuel Cost Over(Under) Recovery Position
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	(KWH)	($)	($)		($)	($)	($)
Balance at June 2020							(9,729,864)
(A) July	1,147,730,706	26,397,806	57,427,982	0.475802	27,324,349	(926,543)	(10,656,407)
(A) August	1,205,263,163	27,721,053	51,095,477	0.450216	23,004,001	4,717,052	(5,939,355)
(A) September	1,119,478,083	25,747,996	44,559,087	0.481382	21,449,942	4,298,054	(1,641,301)
(A) October	974,922,444	22,423,216	44,987,049	0.460872	20,733,271	1,689,945	48,644
(A) November	966,881,582	19,327,963	45,409,234	0.468751	21,285,624	(1,957,661)	(1,909,017)
Include #5570007 retroactively- NONREC						(286,811)	(2,195,828)
Jan - Nov 2020 Adj Non-Incremental Wind Costs						796,322	(1,399,506)
(A) December	1,252,478,969	25,037,055	64,511,918	0.491496	31,707,350	(6,670,295)	(8,069,801)
(A) January 2021	1,409,225,242	28,170,413	64,439,625	0.476733	30,720,496	(2,550,083)	(10,619,884)
Jan - Dec 2020 Adj Non-Incremental Wind Costs						147,706	(10,472,178)
Entry for Incorrect MACSS reports since December 2019 for actual's						1,249,899	(9,222,280)
(A) February	1,316,730,281	26,321,438	59,261,512	0.490142	29,046,556	(2,725,118)	(11,947,398)
Mar Adjustment - Yearly Virginia Defered						326,890	(11,620,508)
(A) March	1,106,031,037	22,109,560	52,203,201	0.467995	24,430,837	(2,321,277)	(13,941,785)
(A) April	1,007,748,034	20,144,883	50,445,786	0.479523	24,189,915	(4,045,032)	(17,986,817)
(A) May	1,028,610,035	20,561,915	47,847,319	0.468793	22,430,488	(1,868,573)	(19,855,390)
(A) June	1,102,836,625	22,045,704	50,037,475	0.486750	24,355,741	(2,310,037)	(22,165,427)
06/21 - 2021 Jan-May Non-Incr Wind Adj						(2,540,707)	(24,706,134)
7/21 - Adjustment March 2019-May 2021 VA Deferred Fuel for Demurrage Charges						306,203	(24,399,931)
(E) July	1,177,011,619	23,528,462	58,344,416	0.486750	28,399,144	(4,870,682)	(29,270,613)
(P) August	1,177,846,000	23,545,142	51,008,463	0.474871 (c)	24,222,453	(677,311)	(29,947,924)
(P) September	1,047,037,000	20,930,270	48,012,604	0.474871 (c)	22,799,805	(1,869,535)	(31,817,459)
(P) October	1,015,980,000	20,309,440	57,424,138	0.474871 (c)	27,269,072	(6,959,632)	(38,777,091)

(a) July 2020 - October 2020: Col. 1 x $0.02300/kWh
(b) Excludes demurrage expense.
(c) Average Virginia energy allocation factor (July '20 - June '21)
(A) Actual; (E) Booking Estimate; (P) Projected.

APCo Exhibit No. ___
Witness: EKK
Schedule 3

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
DERIVATION OF FULL FUEL FACTOR

Line No.					¢/kWh
1	Projected Virginia Jurisdictional Fuel Cost November 2021 - October 2022	$	281,296,848	(A)	
2	Projected Virginia Jurisdictional Energy Sales, November 2021 - October 2022	÷	13,917,703,000	KWH (B)	
3	In-period Fuel Cost Recovery Component				2.021
4	Projected Fuel Cost Underrecovery as of October 31, 2021	$	38,777,091	(C)	
5	Projected Virginia Jurisdictional Energy Sales, November 2021 - October 2022	÷	13,917,703,000	KWH (B)	
6	Prior-period Fuel Cost Underrecovery Component				0.279
7	Total Fuel Factor				2.300

(A) Per APCo Exhibit No.____(EKK) Schedule 4, Column 5.

(B) Per APCo Exhibit No.____(EKK) Schedule 4, Column 1.

(C) Per APCo Exhibit No.____(EKK) Schedule 2, Column 9.

APCo Exhibit No. ___
Witness: EKK
Schedule 4

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
PROJECTED FUEL COST RECOVERY POSITION
AS OF OCTOBER 31, 2022

	Projected Virginia Jurisdictional Energy Sales (1) (KWH)	Projected Fuel Factor Recovery (a) (2) ($)	Projected Total Company Fuel Cost (3) ($)	Projected Monthly Energy Allocation Factor (b) (4)	Projected Virginia Retail Fuel Cost Col. 3 x Col. 4 (5) ($)	Projected Monthly Fuel Cost Over (Under) Recovery Col. 2 - Col. 5 (6) ($)	Projected Cumulative Fuel Cost Over(Under) Position (7) ($)
Cum. Over (Under) Recovery as of October 31, 2021							(38,777,091)
November	1,185,438,000	27,265,074	50,494,123	0.474871	23,978,207	3,286,867	(35,490,224)
December	1,327,391,000	30,529,993	56,058,947	0.474871	26,620,782	3,909,211	(31,581,013)
January 2022	1,419,208,000	32,641,784	64,637,932	0.474871	30,694,696	1,947,088	(29,633,925)
February	1,243,978,000	28,611,494	58,392,694	0.474871	27,729,012	882,482	(28,751,443)
March	1,179,707,000	27,133,261	59,252,985	0.474871	28,137,539	(1,004,278)	(29,755,721)
April	991,589,000	22,806,547	47,814,452	0.474871	22,705,709	100,838	(29,654,883)
May	1,042,857,000	23,985,711	41,133,138	0.474871	19,532,945	4,452,766	(25,202,117)
June	1,045,386,000	24,043,878	43,576,937	0.474871	20,693,435	3,350,443	(21,851,674)
July	1,278,149,000	29,397,427	46,415,328	0.474871	22,041,305	7,356,122	(14,495,552)
August	1,177,418,000	27,080,614	45,189,773	0.474871	21,459,324	5,621,290	(8,874,262)
September	1,022,902,000	23,526,746	37,280,193	0.474871	17,703,292	5,823,454	(3,050,808)
October	1,003,680,000	23,084,640	42,117,946	0.474871	20,000,602	3,084,038	33,230
	13,917,703,000	320,107,169	592,364,448		281,296,848	38,810,321	

(a) November 2021 through October 2022: Col. 1 x $ 0.02300 /kWh.
(b) Average Virginia energy allocation factor (July '20 - June '21)

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APPALACHIAN POWER COMPANY

First Revision of
Sheet No. 52

VA. S.C.C. TARIFF NO. 26

RIDER F.F.R.
(Fuel Factor Rider)

AVAILABILITY OF SERVICE

A Fuel Factor Rider will be applied to all standard customer service rendered under the Applicable Schedules or special contracts. The Fuel Factor Rider shall be calculated by multiplying the customer's kWh by ~~1.999~~2.300¢ per kilowatt-hour.

The Fuel Factor Rider shall remain in effect until such time as modified by the Commission.

Issued: ~~November 1, 2020~~
Pursuant to Procedural Order
Dated: ~~September 21, 2020~~
Case No. PUR-2021~~0~~-00205~~163~~

Effective: November 1, 2021~~0~~

VA. S.C.C. TARIFF NO. 26

RIDER F.F.R.
(Fuel Factor Rider)

AVAILABILITY OF SERVICE

A Fuel Factor Rider will be applied to all standard customer service rendered under the Applicable Schedules or special contracts. The Fuel Factor Rider shall be calculated by multiplying the customer's kWh by 2.300 ¢ per kilowatt-hour.

The Fuel Factor Rider shall remain in effect until such time as modified by the Commission.

APCo Exhibit No. ____
Witness: EKK
Schedule 6

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
ESTIMATED REVENUE INCREASE
ASSOCIATED WITH THE PROPOSED FUEL FACTOR
FOR THE PERIOD NOVEMBER 2021 - OCTOBER 2022

Increase attributable to change in in-period Component:							
Proposed	$	0.02021	/KWH				
Current	-	0.02020					
Increase		0.00001	/KWH				
Projected energy sales	×	13,917,703,000	KWH			$	139,177
Change in Prior-Period True-up Component:							
Increase attributable to implementation of proposed prior-period underrecovery collection component:							
Proposed component	$	0.00279	/KWH				
Projected energy sales	×	13,917,703,000	KWH	$	38,830,391		
Change attributable to removal of current prior-period overrecovery collection component:							
Current component	$	-0.00021	/KWH				
Projected energy sales	×	13,917,703,000	KWH		(2,922,718)		
Subtotal- Increase attributable to change in prior-period component						$	41,753,109
Total estimated 12-month revenue increase/(decrease) associated with the proposed fuel factor change						$	41,892,286

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
SELECTED TYPICAL MONTHLY BILLS

	Tariff Schedule	Energy / Demand Consumption	Bill Amount (a) Under Current Rates VA SCC Tariff No. 26 Effective 8/1/2021 $	Bill Amount (a) Under Proposed Fuel Factor VA SCC Tariff No. 26 Effective 11/1/2021 $	Dollar Increase $	Percent Increase %
RS		100 kWh	18.42	18.72	0.30	1.6%
RS		250 kWh	34.90	35.65	0.75	2.1%
RS		500 kWh	62.39	63.89	1.50	2.4%
RS		750 kWh	89.84	92.10	2.26	2.5%
RS		1,000 kWh	117.31	120.32	3.01	2.6%
RS		1,500 kWh	172.28	176.79	4.51	2.6%
RS		2,000 kWh	227.19	233.21	6.02	2.6%
RS		3,000 kWh	337.07	346.10	9.03	2.7%
RS		5,000 kWh	556.83	571.88	15.05	2.7%
RS		7,500 kWh	831.57	854.14	22.57	2.7%
SWS		1,500 kWh	184.80	189.31	4.51	2.4%
SWS		3,000 kWh	360.64	369.67	9.03	2.5%
SWS		5,000 kWh	595.14	610.19	15.05	2.5%
SWS		10,000 kWh	1,181.40	1,211.50	30.10	2.5%
SWS		30,000 kWh	3,526.40	3,616.70	90.30	2.6%
SWS		50,000 kWh	5,871.41	6,021.91	150.50	2.6%
SGS		375 kWh	45.71	46.84	1.13	2.5%
SGS		1,000 kWh	106.67	109.68	3.01	2.8%
SGS		2,000 kWh	204.23	210.25	6.02	2.9%
SGS		4,000 kWh	399.34	411.38	12.04	3.0%
MGS	Secondary	30 kW / 6,000 kWH	656.34	674.40	18.06	2.8%
	Secondary	50 kW / 12,500 kWH	1,297.96	1,335.58	37.62	2.9%
	Secondary	150 kW / 60,000 kWH	5,776.54	5,957.14	180.60	3.1%
MGS	Primary	250 kW / 50,000 kWH	5,023.85	5,174.35	150.50	3.0%
	Primary	500 kW / 200,000 kWH	17,816.49	18,418.49	602.00	3.4%
GS	Secondary	40 kW / 10,000 kWH	1,050.18	1,080.28	30.10	2.9%
	Secondary	75 kW / 30,000 kWH	2,530.68	2,620.98	90.30	3.6%
	Secondary	500 kW / 150,000 kWH	14,608.61	15,060.11	451.50	3.1%
GS	Primary	1,000 kW / 200,000 kWH	20,022.93	20,624.93	602.00	3.0%
	Primary	1,000 kW / 400,000 kWH	31,186.21	32,390.21	1,204.00	3.9%
LPS	Secondary	1,000 kW / 450,000 kWH	36,792.89	38,147.39	1,354.50	3.7%
	Secondary	2,000 kW / 1,000,000 kWH	75,978.22	78,988.22	3,010.00	4.0%
	Secondary	3,000 kW / 2,000,000 kWH	126,793.84	132,813.84	6,020.00	4.7%
LPS	Primary	3,500 kW / 2,000,000 kWH	130,680.45	136,700.45	6,020.00	4.6%
	Primary	5,000 kW / 3,000,000 kWH	190,285.74	199,315.74	9,030.00	4.7%
LPS	Subtransmission	10,000 kW / 5,000,000 kWH	321,214.45	336,264.45	15,050.00	4.7%
	Subtransmission	20,000 kW / 13,000,000 kWH	719,757.19	758,887.19	39,130.00	5.4%
LPS	Transmission	15,000 kW / 9,000,000 kWH	515,558.64	542,648.64	27,090.00	5.3%
	Transmission	30,000 kW / 19,000,000 kWH	1,056,537.63	1,113,727.63	57,190.00	5.4%

(a) Does not include Sales and Use Tax Rider, Consumption taxes, or Utility tax.

Appendices

APPALACHIAN POWER COMPANY
VIRGINIA S.C.C. CASE NO. PUR-2021-00205
APPENDIX

Section 1 – Actual Data

A1 Actual system sales and energy supply (MWh).

See A1, Attachment 1

A2 Actual generation and purchased power levels (MWh) by source.

See A2, Attachment 1

A3 Actual fuel burns by generating units (MMBtu).

See A3, Attachment 1

A4 Actual fuel and purchased power costs by source.

See A4, Attachment 1

A5 Actual off-system sales volumes and margins along with support for calculation of margins.

See A5, Attachment 1 and Confidential Attachments 2 and 3

A6 Actual generating unit planned and forced outage rates and heat rates along with brief descriptions and durations of outages.

See A6, Confidential Attachment 1, Attachment 2 and Confidential Attachment 3

A7 Discussion of any abnormal operating events and actions taken to minimize fuel and purchased energy costs.

See A7, Attachment 1

Section 2 – Projected

P1 Projections of system sales and energy supply requirements (MWh).

See P1, Attachment 1

P2 Projections of generation and purchased power levels (MWh) by source.

See P2, Confidential Attachment 1

P3 Projections of fuel requirements by generating units (MMBtu).

See P3, Confidential Attachment 1

P4 Projections of fuel and purchased power costs by source.

See P4, Confidential Attachment 1

P5 Projections of off-system sales volumes and margins.

See P5, Attachment 1

P6 Projections of generating unit outage rates and heat rates.

See P6, Confidential Attachment 1

P7 Total fuel factor costs by source by month.

See P7, Attachment 1

APPALACHIAN POWER COMPANY
Sources and Uses of Energy
For the Period July 2020 - June 2021
(GWH)

Line No	Sources of Energy	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	June 2021	12 Mos. Ended 6/30/2020
1	**Total Generation**	2,394.3	2,618 3	1,824 6	1,222.5	1,146.5	1,708.4	2,662.4	2,837 8	1,575.0	1,216 1	2,237.3	2,799.1	24,240
2	Purchased Power:													
3	Purchased Power	715.6	571.8	606.0	930.6	1,147.3	1,245 0	621.4	377.8	848.7	1,026.1	435.5	275.5	8,803
4	Purchased Power - Wind	42.8	43.5	79.7	117.6	154.3	136.8	114.6	117.8	156.6	121.9	89.2	74.8	1,250
5	Other *	1.6	0.1	(1.5)	1.1	0.5	(0.9)	0.0	0.6	5.2	(1.2)	(3.5)	(3.3)	(1)
6	Total Purchased Power	760.0	615.4	684.2	1,049.3	1,302.1	1,381.0	736.0	496.2	1,010.5	1,148.9	521.2	347.1	10,052
7	**Total Sources of Energy**	3,154.3	3,233.7	2,508.8	2,271 8	2,448.5	3,087.4	3,398.4	3,334.0	2,585.5	2,365.0	2,758.5	3,146.2	34,292
	<u>Uses of Energy</u>													
8	Sales of Ultimate Customers:													
9	Residential	1,066.9	936.7	767.8	653.1	757.2	1,276.3	1,454.9	1,261.3	979.4	684.7	714.9	772.1	11,325
10	Commercial	610.3	499.6	488.8	481.3	455.4	529.7	514.1	483.1	447.3	445.1	475.5	499.2	5,929
11	Industrial	727.8	752.5	645.4	779.1	784.0	731.2	670.6	673.6	666.5	731.4	754.8	728.1	8,645
12	All Other Ultimates	73.0	62.8	67.9	66.5	65.9	76.1	68.8	67.3	63.6	62.9	66.0	67.2	808
13	Total Sales to Ultimates	2,478.1	2,251.6	1,970.0	1,980.1	2,062.5	2,613.3	2,708.4	2,485.2	2,156.8	1,924.1	2,011.2	2,066.6	26,708
14	Associated Companies	151.0	145.9	125.8	114.3	121.9	167.6	168.0	146.2	127.7	121.7	129.5	135.8	1,655
15	Municipals and Cooperatives	112.5	105.8	88.0	81.4	82.4	101.3	106.4	98.1	88.6	81.0	82.5	94.7	1,123
16	Losses	109.3	153.8	83.5	40.6	99.6	138.3	172.2	139.1	136.7	108.4	22.6	163.0	1,367
17	Total Internal	2,850.8	2,657.1	2,267.3	2,216.4	2,366.4	3,020.5	3,154.9	2,868.7	2,509.9	2,235.1	2,245.7	2,460.1	30,853
18	Off-System Sales	303.4	576.6	241.5	55.4	82.1	66.9	243.5	465.3	75.6	129.9	512.8	686.1	3,439
19	Other *													-
20	**Total Uses of Energy**	3,154.3	3,233.7	2,508.8	2,271.8	2,448 5	3,087.4	3,398.4	3,334.0	2,585.5	2,366.0	2,758.5	3,146.2	34,292

Appendix A1
Attachment 1
Page 1 of 1

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APPALACHIAN POWER COMPANY
Generation & Purchased Power by Source
For the Period July 2020 - June 2021
(MWH)

Line No.	Source	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	June 2021	12 Mos. Ended 6/30/2020
1	Amos 1	294,298	426,018	111,342	363,896	246,095	99,421	417,176	437,731	46,795	-	-	263,237	2,706,010
2	Amos 2	358,831	314,520	274,485	19,266	84,034	249,067	395,080	386,770	-	213,125	378,237	445,977	3,119,393
3	Amos 3	321,715	784,154	574,553	490,555	-	-	454,383	709,252	348,450	-	709,284	766,240	5,158,586
4	Mountaineer 1	812,136	614,320	429,296	-	306,146	813,375	881,461	790,997	680,922	663,045	660,248	841,711	7,493,656
5	**Total Coal Generation**	1,786,980	2,139,012	1,389,676	873,717	636,276	1,161,863	2,148,100	2,324,751	1,076,167	876,170	1,747,770	2,317,164	18,477,646
6	Clinch River 1 (Natural Gas)	28,247	18,167	7,535	32	-	-	-	-	-	-	12,999	11,156	78,135
7	Clinch River 2 (Natural Gas)	112,668	20,488	6,984	8,298	-	-	-	-	-	8,670	13,190	8,950	179,249
8	Ceredo (C.T. - Natural Gas)	34,809	11,327	1,110	20,326	7,313	23,161	3,526	32,513	2,506	18,277	13,647	42,919	211,435
9	Dresden (C.C. - Natural Gas)	405,293	395,907	384,182	265,407	420,710	437,084	438,449	397,067	415,044	241,265	407,150	384,863	4,592,422
10	Conventional Hydro	46,349	51,800	47,139	52,760	59,840	69,770	65,009	67,862	68,754	66,994	48,177	38,303	682,757
11	Smith Mt. Pumped Storage	65,544	63,796	47,949	39,629	35,152	41,896	35,174	36,843	28,301	29,423	26,054	39,094	488,856
12	Smith Mt. Pumping Energy	(85,632)	(82,221)	(59,973)	(37,698)	(12,840)	(27,348)	(27,856)	(21,286)	(15,793)	(24,666)	(31,678)	(43,360)	(470,352)
13	**Net Company Generation**	2,394,259	2,618,275	1,824,602	1,222,471	1,146,451	1,706,426	2,662,403	2,837,751	1,574,978	1,216,134	2,237,309	2,799,090	24,240,148
14	Market Purchases [1]	567,125	419,428	481,983	828,207	987,200	1,043,983	438,002	193,952	685,088	901,767	334,020	139,879	7,020,634
15	OVEC	147,804	141,024	104,515	91,921	137,130	178,025	166,651	163,438	137,098	126,182	94,437	128,380	1,616,604
16	Wind/Solar [2]	42,844	43,462	79,725	117,588	154,322	136,821	114,632	117,804	156,589	121,921	89,243	74,802	1,249,752
17	Summersville Hydro	704	11,385	19,609	10,461	22,924	23,021	16,707	20,426	26,525	178	7,007	7,257	166,204
18	Out of Period Adjustment [3]	1,550	120	(1,514)	1,126	484	(883)	5	579	5,206	(1,166)	(3,482)	(3,250)	(1,226)
19	**Total Purchased Power**	760,027	615,419	684,318	1,049,303	1,302,059	1,380,967	735,997	496,199	1,010,505	1,148,882	521,225	347,068	10,051,969

Note

[1] Market Purchases include third party purchases, HAPP (hedging book), NUG (Non Utility Gen) & NGK (NAS Batt).

[2] Solar Purchase Power Agreements began in June 2021

[3] OUT-OF-PERIOD ADJUSTMENT - Spot Market Energy for PJM Load Recon

Appalachian Power Company
2021 VA Fuel Factor Filing
Consumed MMBTUs by Month

Plant Name - Commodity	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	June 2021	July 2021	13 Months Ended July 31, 2021
Amos - Coal														
Total Coal Consumed Generation (MMBTU)	9,684,551	15,104,404	9,999,619	8,699,681	3,353,474	4,126,262	12,319,579	14,837,340	3,979,948	2,161,165	10,974,489	14,492,762	15,455,723	125,188,997
Storage Pile Adjustment (MMBTU)	0	0	0	0	0	509,578	0	0	0	0	405,191	0	0	914,769
Total Fuel Oil Consumed Generation (MMBTU)	99,772	44,713	33,648	12,295	25,680	58,624	62,243	21,618	10,671	75,792	46,145	79,900	13,276	584,377
Total Generation Consumption (With Storage Adjustments)	9,784,323	15,149,117	10,033,267	8,711,976	3,379,154	4,694,464	12,381,822	14,858,958	3,990,619	2,236,957	11,425,825	14,572,662	15,468,999	126,688,143
Mountaineer - Coal														
Total Coal Consumed Generation (MMBTU)	8,046,729	6,106,406	4,387,784	0	3,089,399	7,525,135	8,367,666	7,590,523	6,589,376	6,383,417	6,511,077	8,156,992	8,702,528	81,457,032
Storage Pile Adjustment (MMBTU)	0	0	0	0	0	(331,807)	0	0	0	0	0	0	0	(331,807)
Total Fuel Oil Consumed Generation (MMBTU)	7,068	38,730	31,623	151	54,550	4,800	2,593	2,585	6,463	27,873	25,626	1,424	1,005	204,491
Total Generation Consumption (With Storage Adjustments)	8,053,797	6,145,136	4,419,407	151	3,143,949	7,198,128	8,370,259	7,593,108	6,595,839	6,411,290	6,536,703	8,158,416	8,703,533	81,329,716
Ceredo - Natural Gas														
Total Natural Gas Consumed Generation (MMBTU)	432,962	142,324	14,389	251,203	88,993	278,936	42,558	378,785	30,074	227,564	170,012	529,845	407,498	2,995,141
Clinch River - Natural Gas														
Total Natural Gas Consumed Generation (MMBTU)	1,551,499	456,615	171,750	97,998	4,260	8,248	7,681	8,061	3,846	106,527	321,925	246,912	143,243	3,128,564
Dresden - Natural Gas														
Total Natural Gas Consumed Generation (MMBTU)	2,802,324	2,712,374	2,619,976	1,827,204	2,889,208	2,943,230	2,961,914	2,688,138	2,825,672	1,641,121	2,763,804	2,640,777	2,635,431	33,951,173
Total Consumed MMBTUs	22,624,905	24,605,566	17,258,789	10,888,530	9,505,564	15,123,006	23,764,234	25,527,049	13,446,050	10,623,459	21,218,270	26,148,612	27,358,705	248,092,738

APPALACHIAN POWER COMPANY
Generation & Purchased Power Costs by Source
For the Period July 2020 - June 2021

Line No.	Source	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	June 2021	12 Mos. Ended 6/30/2020
1	Coal Generation	37,834,147	45,238,444	30,907,596	18,969,320	13,988,726	24,435,969	44,478,243	48,035,691	21,808,499	18,512,502	37,724,455	48,947,969	390,881,562
2	Natural Gas Generation	8,135,408	5,703,662	4,476,896	3,791,832	4,412,557	7,371,466	7,642,655	13,874,991	7,087,696	5,052,459	8,354,816	9,424,358	85,328,795
3	Hydro Generation	-	-	-	-	-	-	-	-	-	-	-	-	-
4	**Generation Cost ($)**	45,969,555	50,942,106	35,384,492	22,761,152	18,401,283	31,807,435	52,120,898	61,910,682	28,896,195	23,564,960	46,079,271	58,372,327	476,210,357
5	Market Purchases [1]	13,292,276	9,109,282	9,578,151	17,059,220	20,761,983	26,265,984	10,323,148	6,219,311	16,846,505	24,280,990	9,273,109	3,898,244	166,908,204
6	OVEC	3,267,013	3,152,785	2,354,477	2,218,300	3,101,860	4,026,902	3,699,820	3,704,560	3,133,282	2,755,420	2,118,960	2,982,117	36,515,495
7	Wind	1,208,477	1,160,910	2,080,942	3,182,110	4,026,115	3,773,975	3,168,880	3,303,477	4,058,230	3,138,010	2,992,011	2,493,809	34,586,947
8	Summersville Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-
9	**Total Purchased Power Cost ($)**	17,767,767	13,422,976	14,013,570	22,459,630	27,889,958	34,066,861	17,191,848	13,227,347	24,038,017	30,174,420	14,384,079	9,374,170	238,010,646
10	Out of Period Adjustment - SME for PJM Load Reconciliation	30,731	3,891	(42,548)	17,029	4,498	(24,863)	(7,080)	16,896	122,893	(77,342)	(88,073)	(88,368)	(132,338)
11	Off-System Allocation of Sources	(7,386,869)	(12,446,831)	(5,173,798)	(1,333,465)	(1,841,950)	(1,790,403)	(5,515,567)	(12,420,333)	(1,839,798)	(3,903,486)	(11,970,032)	(14,796,973)	(80,419,504)
12	**APCo Net Energy Cost ($)**	56,381,184	51,922,143	44,181,717	43,904,346	44,453,789	64,059,029	63,790,099	62,734,593	51,217,307	49,758,552	48,405,245	52,861,156	633,669,161

*Costs are on an APCo total Company basis

[1] Market Purchases include third party purchases, HAPP (hedging book), NUG (Non Utility Gen) & NGK (NAS Batt).

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Please refer to the document labeled A-5 Confidential Attachment 2 for APCo Monthly Off-System Sales (OSS) Margins and Volumes and to A-5 Confidential Attachment 3 for the allocation of the total company OSS margins to the Virginia jurisdiction for July 2020 through June 2021.

Description of OSS Margin Calculation:

The margins from APCo physical OSS are calculated by subtracting the variable cost of supplying OSS from the related revenue. The process entails assigning the most expensive dispatchable generation and purchased power resources to off-system sales on an hourly basis.

The Power Tracker Application is a third-party application, customized to meet the specific needs of AEP. The application is used for allocating and reporting the costs and revenues associated with OSS for settlement of the Eastern AEP operating companies. The key to the Power Tracker model is an economic dispatch algorithm. The economic dispatch algorithm minimizes cost of serving additional load by increasing output on the resource(s) with lowest incremental/variable cost. On an hourly basis, Power Tracker uses the economic dispatch to determine the resource loading for internal load. This is then compared to the actual resource loading in the hour to determine the incremental change associated with adding the system sales load to the internal load. In this way, resources with the highest incremental cost are assigned to OSS. Remaining resources serve internal load.

The variable cost associated with generation allocated to system sales is computed using the allocation results. Variable costs allocated from generators to sales include fuel, fuel handling, SO_2 emission allowance costs, NO_X emission allowance costs, and chemicals/consumables. Purchased power costs allocated to off-system sales consist of the purchase price of that power.

PJM congestion charges or credits associated with a resource are assigned to OSS or internal load based on the resource assignment to OSS or internal load. The margin from non-physical trading activity is calculated as the net of revenue received from non-physical transactions and transactional costs related to the activity. Transactional costs include the cost of a commodity along with any third party commission or brokerage fees.

APCo's PJM revenues and charges related to its generation and load are accounted for in its own PJM subaccount.

In addition, calculations are performed for transmission line losses and Financial Transmission Rights (FTR) revenue, following the Commission's order in case PUE-2009-0038. These are described below:

Transmission line loss amounts (including credits), billed separately by PJM since June 2007, are not inputs in Power Tracker; they are assigned to OSS or internal load after the Power Tracker allocation, determined based on the resources necessary to serve the internal load. Prior to the Commission's order in PUE-2009-00038, all margins were included in OSS activity, with 75% of OSS margins credited to offset internal load fuel costs for the Virginia customer. Following the Commission's order, PJM transmission line losses in an amount estimated as the jurisdictional share of volumes (MWh) associated with OSS due to the PJM marginal losses being settled financially (vs. formerly "grossed-up" physically at the load) are credited towards internal load fuel costs, resulting in the full 100% credited back to Virginia customers.

Additionally, following the Commission's order in PUE-2009-00038, FTR revenue associated with those Virginia LSE-related FTRs obtained via PJM's Auction Revenue Rights (ARR) allocation, and assigned through the settlement process to OSS, were credited to internal load fuel costs. Seventy-five percent (75%) of other FTR revenue not associated with FTRs obtained through the ARR allocation (i.e., non LSE load-related) were included in the OSS margin calculation, offsetting fuel costs for Virginia customers.

Certain capacity sales and generation hedging activity undertaken for the collective benefit of APCo and its affiliates Indiana Michigan Power Company, Kentucky Power Company and Wheeling Power Company, if any, are allocated between them based on their surplus capacity and energy. In addition, trading activity undertaken for the collective benefit of these four companies is allocated between them based on common shareholder equity. This accounting treatment of these activities is described in the Power Coordination Agreement that took effect January 1, 2014, and amended June 1, 2015, to include WPCo.

Documentation supporting the assignment of the transmission line loss amounts to OSS or internal load, as well as materials related to all assumptions, inputs, and resulting outputs of the Power Tracker process (which involves materials which are voluminous) can be made available for inspection during regular business hours in AEP's Columbus, Ohio office by arrangement.

APCo Total Company Off-System Sales (OSS) Margins and Volumes

Month	OSS Margin ($)	OSS Volume (MWh)
Jul-20	[redacted]	[redacted]
Aug-20	[redacted]	[redacted]
Sep-20	[redacted]	[redacted]
Oct-20	[redacted]	[redacted]
Nov-20	[redacted]	[redacted]
Dec-20	[redacted]	[redacted]
Jan-21	[redacted]	[redacted]
Feb-21	[redacted]	[redacted]
Mar-21	[redacted]	[redacted]
Apr-21	[redacted]	[redacted]
May-21	[redacted]	[redacted]
Jun-21	[redacted]	[redacted]

APPALACHIAN POWER COMPANY

Allocation of Off-System Sales Margin to VA Jurisdiction
Using Energy Allocation Factors
For the Period July 2020 - June 2021

Line No.	Description	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	June 2021	13 Mos. Ended 6/30/2020
1	Off-system Sales Margin	[redacted]												
2	Off-system Sales Margin @ 75%													
3	VA Energy Allocation Factor													
4	Credit Allocable to VA Jurisdiction ($)													

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APCo Generating Unit Forced and Planned Outage Rates
July 2020 - June 2021

Unit Names	July-20			August-20			September-20		
	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate (EMOR)	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate (EMOR)	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate (EMOR)
AM1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AM2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AM3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CR1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CR2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DR1A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DR1B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DR1S	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MT1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

This information is presented as Equivalent Forced Outage Rate (EFOR) and Equivalent Planned Outage Rate (EPOR), which include both full outage and equivalent derated hours due to curtailments. For example, a 10 MW forced curtailment on a 100 MW unit for 10 hours is equivalent to a one-hour forced outage.

APCo Generating Unit Forced and Planned Outage Rates
July 2020 - June 2021

Unit Names	October-20			November-20			December-20		
	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate
AM1	[redacted]								
AM2									
AM3									
CE1									
CE2									
CE3									
CE4									
CE5									
CE6									
CR1									
CR2									
DR1A									
DR1B									
DR1S									
MT1									

This information is presented as Equivalent Forced Outage Rate (EFOR) and Equivalent Planned Outage Rate (EPOR), which include both full outage and equivalent derated hours due to curtailments. For example, a 10 MW forced curtailment on a 100 MW unit for 10 hours is equivalent to a one-hour forced outage.

APCo Generating Unit Forced and Planned Outage Rates
July 2020 - June 2021

Unit Names	January-21			February-21			March-21		
	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate
AM1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AM2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AM3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CE6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CR1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CR2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DR1A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DR1B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DR1S	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MT1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

This information is presented as Equivalent Forced Outage Rate (EFOR) and Equivalent Planned Outage Rate (EPOR), which include both full outage and equivalent derated hours due to curtailments. For example, a 10 MW forced curtailment on a 100 MW unit for 10 hours is equivalent to a one-hour forced outage.

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APCo Generating Unit Forced and Planned Outage Rates
July 2020 - June 2021

Unit Names	April-21			May-21			June-21		
	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate	Equivalent Forced Outage Rate (EFOR)	Equivalent Planned Outage Rate (EPOR)	Equivalent Maintenance Outage Rate
AM1	[redacted]								
AM2									
AM3									
CE1									
CE2									
CE3									
CE4									
CE5									
CE6									
CR1									
CR2									
DR1A									
DR1B									
DR1S									
MT1									

This information is presented as Equivalent Forced Outage Rate (EFOR) and Equivalent Planned Outage Rate (EPOR), which include both full outage and equivalent derated hours due to curtailments. For example, a 10 MW forced curtailment on a 100 MW unit for 10 hours is equivalent to a one-hour forced outage.

Unit Name	Event Type	Start Date	End Date	Description	Duration (Hours)
Amos 1	U1	7/6/2020 17:21	7/7/2020 6:47	Loss of steam supply from AM2 caused unit to trip	13.43
Amos 1	MO	3/5/2021 22:00	3/15/2021 0:00	to perform Boiler I/R (including hydro and air test for leaks) and pull new cable for FFC-1.	217
Amos 1	U1	7/25/2020 14:05	7/29/2020 0:00	Tube Leak - Economizer 2nd RH Right Side Elevation 95	81.92
Amos 1	MO	9/2/2020 0:00	9/13/2020 0:00	To i/r Deaerator Level Control Valve (CRV-301), i/r Deaerator Level Bypass Valve (CMO-301), i/r 2A Circulating Water Pump, i/r Inverter, i/r FD Fan Reserve Feed to Normal Feed operations, Boiler Hydro i/r.	264
Amos 1	U1	3/5/2021 4:27	3/5/2021 22:00	EHC System Leak	17.55
Amos 1	U1	7/1/2020 9:12	7/1/2020 10:35	Tripped while swapping FD fans feeds	1.38
Amos 1	MO	7/29/2020 12:00	7/30/2020 15:47	FD Fan i/r. The Fan is on Reserve Feed, when swapping to the Normal Feeds on prior Start Up the Turbine Tripped.The unit can startup/operate with this liability.	27.78
Amos 1	U1	8/31/2020 10:51	9/2/2020 0:00	Under ground cable from 501 Transformer to 301 Transformer grounded phase 2.	37.15
Amos 1	U1	6/7/2021 2:01	6/14/2021 16:35	due to Boiler Feedpump shaft position trip	182.57
Amos 1	U1	7/5/2020 21:20	7/6/2020 12:10	Unit trip - Feed pump control valve issue	14.83
Amos 1	U1	9/17/2020 9:42	9/17/2020 21:54	Reason Unknown - Feedpump run back	12.2
Amos 1	MO	11/21/2020 2:40	12/22/2020 0:25	#1 Control Valve LVDT repair, 2-2 Intercept Valve repairs, EHC pump Replacement/ Relief Valve replacement, #2 Turbine Vibration Absorber Expansion Joint replacement.	741.75
Amos 1	PO	3/15/2021 0:00	6/7/2021 2:01	Planned Outage, SCR Catalyst, Waterwall Panels	2018.02
Amos 1	MO	6/25/2021 4:49	6/25/2021 8:42	Repair #1 Control Valve Leak Off line flange leak	3.88
Amos 2	U1	7/6/2020 17:21	7/8/2020 7:50	ID Fan Issue	38.48
Amos 2	MO	11/14/2020 0:30	11/30/2020 0:00	#1 PA Fan i/r	383.5
Amos 2	MO	5/28/2021 18:00	6/2/2021 5:39	Boiler i/r. Contractor will be onsite to complete boiler inspections.	107.65
Amos 2	U1	5/26/2021 22:33	5/28/2021 18:00	Tube Leak	43.45
Amos 2	U2	7/28/2020 19:27	8/1/2020 0:00	Tube Leak - 4 tubes to be repaired. 2 in the 1st RH and 2 Waterwall tubes. Repairs are expected to be complete on 7/30 @ 1900 followed by a hydro to check for more leaks.	76.55
Amos 2	MO	3/15/2021 0:00	4/6/2021 4:57	Low Pressure Heaters #1 and #4 Inspection and Repairs	532.95
Amos 2	U1	4/9/2021 14:17	4/16/2021 5:07	High Conductivity and low PH associated with #5 demin.	158.83
Amos 2	MO	8/1/2020 0:00	8/8/2020 0:00	Repair 7B Heater Feedwater Safety Valve & #1 Air Heater Casing leak, #1 EHC Pump piping revision to reduce vibration and replace Feedwater Flow Meeter transmitter on FFC4.	168
Amos 2	U1	1/30/2021 16:53	1/31/2021 2:17	Unit tripped offline. NERC protective relay on 2D Transformer misoperation sudden pressure relay failure	9.4
Amos 2	MO	2/24/2021 1:03	2/27/2021 0:00	Boiler i/r, BFP Turbine Top Oil Cooler leak repairs.	70.95

Amos 2	U1	5/20/2021 5:50	5/20/2021 19:45	Feed Water Run Back lead to Low Flow Trip	13.92
Amos 2	MO	2/27/2021 0:00	3/15/2021 0:00	Required MATS inspections and 2D Transformer Testing	383
Amos 2	PO	10/3/2020 0:23	11/2/2020 22:13	General Maintenance	742.83
Amos 2	U1	4/16/2021 9:16	4/16/2021 16:16	sudden trip from low main steam temperature	7
Amos 2	U1	6/2/2021 16:46	6/3/2021 3:13	Lost steam flow to Feedpump	10.45
Amos 3	MO	7/4/2020 0:00	7/13/2020 0:30	Repairs to the Primary Air ductwork and Fuel Output damper for #11 Pulverizer	216.5
Amos 3	MO	3/19/2021 1:02	3/27/2021 0:00	Boiler i/r, Hydro, #2 Air Heater inspection.	190.97
Amos 3	MO	10/24/2020 2:11	11/8/2020 0:00	to repair Main Steam Attemperator line.	358.82
Amos 3	PO	11/8/2020 0:00	11/27/2020 23:00	General Maintenance, Main Steam Attemperator	479
Amos 3	PO	11/27/2020 23:00	1/4/2021 17:11	General Maintenance, Main Steam Attemperator	906.18
Amos 3	U1	1/11/2021 4:52	1/11/2021 14:35	Turbine upset HP flashtank level control	9.72
Amos 3	U1	1/12/2021 1:11	1/12/2021 22:44	Main steam supply issues / temperator issues HP flashtank level control	21.55
Amos 3	U1	1/8/2021 16:00	1/11/2021 1:19	Tube Leak in the lower furnace	57.32
Amos 3	MO	6/28/2020 0:59	7/4/2020 0:00	Tube leak	72
Amos 3	U1	7/13/2020 0:30	7/17/2020 7:00	Tube Leak - Boiler	102.5
Amos 3	SF	1/4/2021 17:11	1/5/2021 0:00	Condenser Tube Leak	6.82
Amos 3	U1	1/5/2021 0:00	1/8/2021 16:00	Condenser Tube Leak	88
Amos 3	U1	7/17/2020 7:00	7/18/2020 20:04	Reheat Excitation Breaker	37.07
Amos 3	PO	3/27/2021 0:00	5/4/2021 23:59	to replace Phase 3 GSU Oil Pumps, repair BRV-11 & 12 Packing Leaks, and BOP i/r	935.98
Ceredo 1	MO	12/7/2020 7:00	12/8/2020 17:40	Exhaust stack inspection	34.67
Ceredo 1	PO	9/19/2020 7:00	9/24/2020 16:55	Boroscope Inspection	129.92
Ceredo 1	U1	10/14/2020 7:16	10/14/2020 7:57	Unit Started, 52G synchronizing breaker failed to close.	0.68
Ceredo 1	MO	10/14/2020 10:30	10/14/2020 12:35	Pull breaker 1 down for closer examination of issues experienced when unit would not sync to system	2.08
Ceredo 2	MO	12/7/2020 7:00	12/8/2020 17:40	Exhaust stack inspection	34.67
Ceredo 2	MO	9/19/2020 7:00	9/20/2020 7:00	Pre-Planned Outage work.	24
Ceredo 2	PO	9/20/2020 7:00	9/24/2020 16:56	Boroscope Inspection	105.93
Ceredo 3	MO	10/21/2020 14:00	10/21/2020 14:23	Troubleshoot diagnostic alarm on exciter controls. Alarm is not stopping unit from running or being available, but must power down system to troubleshoot.	0.38
Ceredo 3	MO	12/8/2020 7:00	12/9/2020 16:51	Exhaust stack inspection	33.85
Ceredo 3	SF	12/9/2020 17:20	12/9/2020 18:57	Unit failed to start, personnel changing out control card	1.62
Ceredo 3	PO	9/21/2020 7:00	9/24/2020 16:56	Boroscope Inspection	81.93
Ceredo 4	MO	12/9/2020 7:00	12/9/2020 16:51	Exhaust Stack Inspection	9.85
Ceredo 4	PO	9/21/2020 7:00	9/24/2020 16:56	Boroscope Inspection	81.93
Ceredo 5	MO	12/10/2020 7:00	12/10/2020 16:16	Exhaust Stack Inspection	9.27
Ceredo 5	PO	9/21/2020 7:00	9/25/2020 15:17	Boroscope Inspection	104.28
Ceredo 6	MO	12/10/2020 7:00	12/10/2020 16:16	Exhaust Stack Inspection	9.27
Ceredo 6	U1	8/12/2020 12:23	8/12/2020 17:08	GE Turbine control system	4.75
Ceredo 6	PO	9/21/2020 7:00	9/25/2020 17:06	Boroscope Inspection	106.1
Clinch River 1	MO	8/12/2020 14:00	8/17/2020 17:00	Boiler i/r and HP Heater repairs.	123
Clinch River 1	PO	10/10/2020 0:00	11/6/2020 17:33	Planned Outage	666.55
Clinch River 1	U1	6/29/2020 0:01	7/11/2020 15:55	Tube leak	255.92
Clinch River 1	U1	7/13/2020 20:55	7/17/2020 6:12	Tube Leak - SE Wing Wall	81.28
Clinch River 1	U1	7/27/2020 15:00	8/6/2020 17:03	Tube Leak - Waterwall	242.05
Clinch River 1	MO	5/29/2021 0:00	6/5/2021 18:00	to Drain Circ Water intake flume repair intake screens and clean condenser.	186

Clinch River 1	MO	9/1/2020 0:00	9/2/2020 16:40	Inspect and repair Condenser Waterbox leaks.	40.67
Clinch River 1	MO	2/2/2021 7:00	2/3/2021 15:21	Voltage Regulator Controls System repairs	32.35
Clinch River 1	U1	2/15/2021 15:00	2/18/2021 8:15	<OMC!> FO due to Nat Gas Supply Issues	65.25
Clinch River 1	PO	4/17/2021 0:00	5/7/2021 19:10	Planned Outage	499.17
Clinch River 1	U1	10/5/2020 10:32	10/7/2020 0:00	Boiler feed pump problem.	37.47
Clinch River 2	U1	8/9/2020 10:09	8/9/2020 10:59	Erratic air flow transmitter	0.83
Clinch River 2	PO	4/24/2021 0:00	5/14/2021 2:15	Planned Outage	482.25
Clinch River 2	MO	9/23/2020 0:00	9/23/2020 15:20	Boiler internal water cooled door leak i/r	15.33
Clinch River 2	PO	10/31/2020 0:00	11/25/2020 15:40	Planned Outage	616.67
Clinch River 2	U1	9/23/2020 15:20	10/1/2020 19:03	Tube Leak	195.72
Clinch River 2	MO	5/29/2021 0:00	6/5/2021 18:00	to Drain Circ Water intake flume repair intake screens and clean condenser.	186
Clinch River 2	MO	9/16/2020 0:00	9/17/2020 16:36	Condenser i/r	40.6
Clinch River 2	MO	2/2/2021 7:00	2/3/2021 15:21	Voltage Regulator Controls System repairs	32.35
Clinch River 2	U1	2/15/2021 15:00	2/18/2021 8:15	<OMC!> FO due to Nat Gas Supply Issues	65.25
Clinch River 2	U1	6/28/2021 14:24	6/29/2021 1:39	Boiler Feed Pump Regulating Valve issue	11.25
Dresden 1A	PO	10/10/2020 0:22	10/20/2020 6:00	General Maintenance, tie in new instrument air compressors, general HRSG Valve maintenance	245.63
Dresden 1A	MO	11/6/2020 0:39	11/7/2020 21:49	To replace the number 6 & 7, 8 ignition cans.	45.17
Dresden 1A	U1	10/21/2020 0:44	10/21/2020 1:37	RH Attemperator Valve controler failed	0.88
Dresden 1A	U1	11/28/2020 9:41	11/28/2020 9:44	HRSG A reheat steam temp high due to Steam turbine trip/ B HP drum level high	0.05
Dresden 1A	U1	11/28/2020 10:43	11/28/2020 11:52	HRSG A reheat steam temp high due to Steam turbine trip/ B HP drum level high,1A CT had to be unloaded to relieve pressure on a valve.	1.15
Dresden 1A	U1	4/27/2021 11:31	4/28/2021 23:39	Attemperator Line Break	36.13
Dresden 1A	U1	10/20/2020 6:00	10/20/2020 16:44	HRH Bypass Repairs Feed back control repair	10.73
Dresden 1A	PO	4/17/2021 0:45	4/27/2021 10:32	General Maintenance to include LCI upgrade to replace #1262841, Replace Inlet air filters	249.78
Dresden 1A	U1	10/21/2020 1:47	10/21/2020 20:54	Steam turbine turning gear failed to engage	19.12
Dresden 1B	PO	10/10/2020 0:23	10/20/2020 6:00	General Maintenance, tie in new instrument air compressors, general HRSG Valve maintenance	245.62
Dresden 1B	U1	10/20/2020 20:10	10/20/2020 23:12	RH Attemperator Valve controler failed	3.03
Dresden 1B	U1	11/28/2020 9:34	11/28/2020 15:43	Unit tripped on drum level indication from the steamer	6.15
Dresden 1B	U1	4/27/2021 11:31	4/29/2021 1:30	A HRH Bypass Attemperator Line Break	37.98
Dresden 1B	U1	10/20/2020 6:00	10/20/2020 17:51	RH Bypass Repairs	11.85
Dresden 1B	PO	4/17/2021 0:45	4/27/2021 11:31	General Maintenance to replace #1263042 Replace inlet Air filters	250.77
Dresden 1B	U1	10/21/2020 0:26	10/21/2020 22:37	STG turning gear failed to engage	22.18
Dresden 1S	PO	10/10/2020 0:42	10/20/2020 6:00	General Maintenance, tie in new instrument air compressors, general HRSG Valve maintenance	245.3
Dresden 1S	U1	11/28/2020 9:34	11/28/2020 15:19	Unit tripped on drum level indication	5.75
Dresden 1S	U1	4/27/2021 11:31	4/29/2021 0:52	Attemperator Line Break	37.35
Dresden 1S	U1	10/20/2020 6:00	10/20/2020 17:51	Condenser Vacuum Pump and RH Bypass Repairs	11.85
Dresden 1S	PO	4/17/2021 0:45	4/27/2021 11:31	General Maintenance to replace #1263048 replace inlet air filters	250.77
Dresden 1S	U1	10/21/2020 0:42	10/21/2020 22:14	STG Turning gear failed to engage	21.53
Mountaineer 1	MO	8/3/2020 1:49	8/8/2020 0:00	Ash Hopper Tube Leak repair and repack the Feedpump Recirc Valve (FRV400)	118.18

Mountaineer 1	U2	3/26/2021 18:44	4/6/2021 12:24	Tube Leak	257.67
Mountaineer 1	U2	9/8/2020 23:33	9/12/2020 4:05	SH Tube Leak	76.53
Mountaineer 1	U2	11/18/2020 4:11	11/26/2020 17:01	Tube Leak	204.83
Mountaineer 1	U1	5/17/2021 15:08	5/22/2021 8:52	Economizer Tube Leak	113.73
Mountaineer 1	PO	9/26/2020 1:34	11/7/2020 3:37	General Maintenance	1011.05
Mountaineer 1	MO	8/8/2020 16:43	8/8/2020 19:31	Unit coming off for overspeeds	2.8
* Notes:					

PO Planned Outage	An outage that is scheduled well in advance and is of a predetermined duration, lasts for several weeks, and occurs only once or
MO Maintenance Outage	An outage that can be deferred beyond the end of the next weekend (Sunday at 2400 hours), but requires that the unit be removed
SF Startup Failure	An outage that results when a unit is unable to synchronize within a specified startup time following an outage or Reserve
U1 Unplanned Outage-Immediate	An outage that requires immediate removal of a unit from service, another Outage State, or a Reserve Shutdown state.
U2 Unplanned Outage-Delayed	An outage that does not require immediate removal of a unit from the in-service state but requires removal within six hours. This
U3 Unplanned Outage-Postponed	An outage that can be postponed beyond six hours but requires that a unit be removed from the in-service state before the end of

APCo Generating Units
Monthly Heat Rate (Actual)
(BTU/KWh)
August 2019 through June 2020

MONTH	Amos 1	Amos 2	Amos 3	Ceredo 1	Ceredo 2	Ceredo 3	Ceredo 4	Ceredo 5	Ceredo 6	Clinch River 1	Clinch River 2	Dresden	Mountaineer 1
JUL 20	[redacted]												
AUG 20	[redacted]												
SEP 20	[redacted]												
OCT 20	[redacted]												
NOV 20	[redacted]												
DEC 20	[redacted]												
JAN 21	[redacted]												
FEB 21	[redacted]												
MAR 21	[redacted]												
APR 21	[redacted]												
MAY 21	[redacted]												
JUN 21	[redacted]												

Actions taken to minimize fuel costs

Coal Procurement

APCo's coal procurement strategy includes layering short-term and long-term supply agreements into the existing portfolio to gradually increase the committed position. This supply mix provides for the necessary flexibility in meeting the demands of APCo's coal-fired plants. Such flexibility allows APCo to respond to the variability of coal consumption, and reduces the risk of being over-supplied. The strategy also enables APCo to secure long-term supply, when reasonable to do so, while also securing a portion of its fuel needs on a short-term basis. Variability in burn is mainly a result of low natural gas prices and the increasing use of renewables.

APCo also seeks to minimize the cost of coal by securing the majority of its coal supply requirements through competitive bidding methods, such as publically available Request for Proposals (RFPs). In addition to the competitive bidding process, APCo often receives unsolicited offers for coal, which are examined in view of recent offers received through competitive bids, as well as prices quoted for various coals within industry publications. On an as-needed basis, APCo may procure select amounts of coal on the over-the-counter market, if such coal is necessary to fulfill short-term requirements.

Beyond its efforts to secure coal supply agreements through the means previously noted, APCo also works with existing coal supply vendors to re-price or renegotiate existing agreements, when possible or appropriate, to obtain the most advantageous price and/or terms possible. APCo also utilizes agreements with market price reopener provisions when available, thus ensuring APCo's customers are not unduly burdened by higher market prices that might be in effect at the time of the coal supply agreement's inception.

Natural Gas Procurement

Due to fluctuating requirements associated with the variable operation of natural gas-fired power plants, APCo's natural gas procurement strategy is to maintain a mix of firm and interruptible pipeline transportation agreements and to rely predominantly on daily spot market purchases for supply. This strategy provides the reliability and the flexibility necessary to meet instantaneous, hourly and daily natural gas flow requirements. Daily spot-market transactions are made competitively using a web-based platform known as the Intercontinental Exchange (ICE). ICE also provides real-time pricing transparency for the markets in which APCo transacts. At times when the Dresden Plant is expected to operate every day for an entire month, APCo may issue an RFP to obtain monthly baseload natural gas supply, for a portion of expected consumption. Monthly baseload purchases reduce exposure to potential volatility in the daily natural gas market. The natural gas arrangements utilized by APCo provide the required flexibility necessary to reliably operate APCo's system, while minimizing overall total fuel costs.

Purchase Power

American Electric Power Service Corporation's (AEPSC) Regulated Commercial Operations group separately coordinates the dispatch of generation owned by each regulated AEP East Operating Company. The group engages in bulk power market activity, to economically supply native load requirements and to produce off-system sales margins which help to lower the rates of APCo customers.

Daily planning and execution ensure that the proper mix of generation resources and market purchases are utilized for the benefit of customers. By prudently managing APCo's generation resources within the PJM markets, Commercial Operations continually acts to minimize the cost to APCo of operating in the PJM RTO.

APPALACHIAN POWER COMPANY
Sources and Uses of Energy
For the 12 Months Ending October 2022
(GWH)

Line No.	Sources of Energy	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	12 Mos. Ending 10/31/2022
	Fossil Generation by Plant:													
	AMOS	1,133.9	1,709.0	1,691.4	1,512.3	978.6	955.5	1,148.5	1,221.2	1,735.7	1,741.4	1,448.7	732.7	16,008.8
	CEREDO	-	-	18.1	25.2	-	-	-	7.2	71.0	31.7	27.8	-	181.0
	CLINCH RIVER - GAS	-	-	5.0	5.1	-	-	5.3	26.0	71.8	77.3	39.9	39.6	270.2
	DRESDEN	445.4	471.0	479.4	423.8	441.8	231.0	423.3	394.8	406.7	411.8	405.8	331.8	4,866.5
	MOUNTAINEER	627.1	949.5	876.9	662.6	50.2	-	386.9	638.8	819.2	908.4	760.7	851.0	7,531.3
	Total Fossil Generation	2,206.4	3,129.5	3,070.7	2,629.0	1,470.5	1,186.4	1,964.0	2,288.1	3,104.5	3,170.6	2,682.9	1,955.1	28,857.8
	Hydro Generation	52.8	59.7	68.4	72.5	75.2	82.8	68.2	48.8	27.0	28.1	28.0	33.7	645.3
1	Total Generation	2,259.2	3,189.2	3,139.1	2,701.5	1,545.7	1,269.2	2,032.2	2,336.9	3,131.5	3,198.7	2,711.0	1,988.9	29,503.1
2	Purchased Power:													
3	Purchased Power	442.5	289.7	410.2	425.7	1,027.6	832.4	542.6	341.9	225.7	188.9	185.2	437.5	5,350.0
4	Purchased Power - Wind - Camp Grove, Fowler Ridge & Bluff Point	88.0	90.2	94.0	79.6	86.7	85.6	66.4	48.4	32.3	32.3	45.8	76.8	826.1
5	Purchased Power - Wind - Beech Ridge & Grand Ridge	51.7	49.4	56.6	51.4	58.6	54.9	40.0	30.7	20.4	18.2	26.5	42.6	501.1
6	Other *	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Purchased Power	582.2	429.2	560.9	556.7	1,173.0	972.9	649.0	421.0	278.5	239.4	257.5	557.0	6,677.2
8	PJM Transmission losses	62.2	72.8	78.3	69.1	65.7	54.7	55.2	58.4	66.6	66.1	57.2	56.3	762.6
9	Total Sources of Energy	2,903.6	3,691.2	3,778.3	3,327.3	2,784.3	2,296.9	2,736.4	2,816.4	3,476.6	3,504.2	3,025.6	2,602.1	36,942.8
	Uses of Energy													
10	Sales of Ultimate Customers:													
11	Residential	886.7	1,264.1	1,421.1	1,150.4	978.1	721.3	675.1	716.1	986.9	902.6	696.9	638.6	11,037.9
12	Commercial	502.7	482.7	528.5	471.3	474.5	415.2	482.6	488.1	593.3	534.7	468.8	475.5	5,918.0
13	Industrial	806.0	713.9	714.8	702.2	752.6	692.7	767.4	731.1	785.4	759.8	729.3	777.0	8,932.1
14	All Other Ultimates	75.8	72.0	75.2	71.3	72.0	63.4	70.9	67.2	72.2	68.3	68.9	70.9	848.0
15	Customer Choice													
16	Total Sales to Ultimates	2,271.2	2,532.7	2,739.6	2,395.2	2,277.2	1,892.5	1,996.0	2,002.5	2,437.8	2,265.4	1,963.9	1,962.0	26,736.0
17	Associated Companies	130.7	159.2	172.4	164.5	146.9	129.9	122.6	127.6	156.3	142.6	125.3	117.1	1,695.0
18	Municipals and Cooperatives	85.7	97.4	106.3	93.6	89.7	79.3	83.4	92.3	103.3	102.1	89.8	82.7	1,105.5
19	Losses	116.9	252.7	273.6	240.9	230.2	191.4	102.1	202.6	80.0	229.4	197.4	198.6	2,315.9
20	Total Internal	2,604.5	3,042.0	3,291.9	2,894.2	2,744.1	2,293.2	2,304.0	2,425.0	2,777.4	2,739.5	2,376.3	2,360.3	31,852.4
21	Off-System Sales	299.1	649.2	486.4	433.1	40.3	3.7	432.3	391.4	699.2	764.7	649.3	241.8	5,090.4
22	Total Uses of Energy	2,903.6	3,691.2	3,778.3	3,327.3	2,784.3	2,296.9	2,736.4	2,816.4	3,476.6	3,504.2	3,025.6	2,602.1	36,942.8

* Other represents difference due to rounding.

Appendix
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Appendix
P2 Public Attachment 1
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APPALACHIAN POWER COMPANY (APCo)
November 1, 2021 - October 31, 2022
PROJECTED GENERATION AND PURCHASED POWER LEVELS BY SOURCE (MWh)

Unit	2021 Nov	2021 Dec	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct	Nov. 21 - Oct. 22 Net Generation (MWH)
Amos 1	[redacted]												
Amos 2													
Amos 3													
Mountaineer 1													
Total Coal Generation													
Ceredo (C.T. - Natural Gas)													
Clinch River 1 (Steam Gas - Natural Gas)													
Clinch River 2 (Steam Gas - Natural Gas)													
Dresden (C.C. - Natural Gas)													
Conventional Hydro													
Smith Mt. Pumped Storage													
Less Pumping Energy													
Net Company Generation													
Purchased Power:													
OVEC													
Market Purchases													
Summersville													
Wind (Camp Grove & Fowler Ridge)													
Wind (Beech Ridge & Grand Ridge)													
Wind (Bluff Point)													
Solar (Depot)													
PJM Marginal Losses													
Other													
Total Purchased Power													
Less Off-System Sales													
Net Purchased Power													
APCo Net Energy Supply													

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Appendix
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APPALACHIAN POWER COMPANY (APCo)
November 1, 2021 - October 31, 2022
PROJECTED FUEL REQUIREMENT (MBtu)

PUBLIC VERSION

Unit	2021 Nov	2021 Dec	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct
Amos 1	[redacted]											
Amos 2												
Amos 3												
Ceredo 1												
Ceredo 2												
Ceredo 3												
Ceredo 4												
Ceredo 5												
Ceredo 6												
Clinch River 1 (Gas)												
Clinch River 2 (Gas)												
Dresden												
Mountaineer												

Appendix
P4 Public Attachment 1
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APPALACHIAN POWER COMPANY (APCo)
November 1, 2021 - October 31, 2022
FORECASTED FUEL AND PURCHASED POWER COSTS BY SOURCE ($)

PUBLIC VERSION

Unit	2021 Nov	2021 Dec	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct	Nov. 21 - Oct. 22 Fuel Expenses ($)
Amos 1	[redacted]												
Amos 2													
Amos 3													
Mountaineer 1													
Total Coal Fuel Cost													
Ceredo (C.T. - Natural Gas) Cost													
Clinch River 1 (Steam Gas - Natural Gas) Cost													
Clinch River 2 (Steam Gas - Natural Gas) Cost													
Dresden (C.C. - Natural Gas) Cost													
Net Company Fuel Cost													
Purchased Power:													
OVEC													
Market Purchases													
Solar (Depot)													
Wind (Camp Grove & Fowler Ridge)													
Wind (Beech Ridge & Grand Ridge)													
Wind Excluded from Fuel Filing													
Total Purchased Power													
Less Off-System Sales													
Less 75% of Off System Sales Margin Credit													
Less 100% of Incremental Transmission Line Loss Margins													
Less PJM LSE Transmission Losses													
Less FTR Revenues													
Less PJM Congestion Charges													
Net Purchased Power Cost													
APCo Fuel & Purchased Power Includable Cost													

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APPALACHIAN POWER COMPANY
Projections of Off-System Sales Margins and Volumes
For the 12 Months Ending October 2022

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	12 Mos. Ending 10/31/2022
Total Margins ($000)	(1,822.9)	(3,937.6)	(3,066.2)	(3,050.5)	46.3	(1,588.4)	(2,545.7)	(2,265.2)	(7,235.2)	(6,697.5)	(5,065.8)	(1,237.1)	(38,465.7)
Total Sales (GWH)	299.1	649.2	486.4	433.1	40.3	3.7	432.3	391.4	699.2	764.7	649.3	241.8	5,090.4

APPALACHIAN POWER COMPANY (APCo)
November 1, 2021 - October 31, 2022
PROJECTED FORCED OUTAGE RATE

PUBLIC VERSION

Unit	2021 Nov	2021 Dec	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct
Amos 1	[redacted]											
Amos 2												
Amos 3												
Ceredo 1												
Ceredo 2												
Ceredo 3												
Ceredo 4												
Ceredo 5												
Ceredo 6												
Clinch River 1 (Gas)												
Clinch River 2 (Gas)												
Dresden												
Mountaineer 1												

APPALACHIAN POWER COMPANY (APCo)
November 1, 2021 - October 31, 2022
PROJECTED AVERAGE HEAT RATE (Btu/kWh)

PUBLIC VERSION

Unit	2021 Nov	2021 Dec	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct
Amos 1	[redacted]											
Amos 2	[redacted]											
Amos 3	[redacted]											
Ceredo 1	[redacted]											
Ceredo 2	[redacted]											
Ceredo 3	[redacted]											
Ceredo 4	[redacted]											
Ceredo 5	[redacted]											
Ceredo 6	[redacted]											
Clinch River 1 (Gas)	[redacted]											
Clinch River 2 (Gas)	[redacted]											
Dresden	[redacted]											
Mountaineer 1	[redacted]											

APPALACHIAN POWER COMPANY
Projected Net Energy Requirement
and Includable Cost

For the 12 Months Ending October 2022

Line No.	Net Energy Cost ($000)	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	12 Mos. Ending 10/31/2022
1	Fossil Generation (A/C 151)	42,492.0	60,063.1	59,769.6	51,401.2	27,850.8	21,840.6	34,831.0	43,371.6	59,915.1	60,129.1	47,417.7	33,418.0	542,509.9
2	Plus:													
3	Purchases (total cost)	10,643.2	6,758.2	11,621.7	13,042.7	27,317.6	20,316.7	11,666.9	6,677.6	4,845.8	4,058.0	3,514.0	10,433.0	130,895.5
4	Purchase Power Wind Energy - Camp Grove, Fowler Ridge & Bluff Point	4,739.9	5,097.1	5,505.7	4,680.5	4,715.5	4,772.7	3,631.2	2,631.5	1,848.2	1,791.0	2,484.7	4,199.1	46,097.2
5	Purchase Power Wind Energy - Beech Ridge & Grand Ridge	4,704.3	4,883.3	5,736.2	5,537.4	5,350.0	5,109.4	3,654.2	2,850.3	2,080.0	1,879.6	2,499.9	3,749.8	48,034.4
6	Less:													
7	Energy Generated for Off-System Sales (A/C 151)	6,342.5	12,907.0	9,676.6	8,481.8	875.1	108.0	7,579.9	7,834.8	14,157.7	15,224.4	12,079.7	4,920.8	100,188.4
8	Total Net Energy Cost	56,236.9	63,894.8	72,956.6	66,180.0	64,368.8	51,931.5	46,203.4	47,696.2	54,531.4	52,633.3	43,836.7	46,879.1	667,348.5
9	Incremental Wind Excluded from Fuel Filing - Camp Grove, Fowler Ridge & Bluff Point	(1,577.9)	(1,696.8)	(1,832.9)	(1,558.1)	(1,569.8)	(1,588.8)	(1,208.8)	(876.0)	(615.3)	(596.2)	(827.2)	(1,397.9)	(15,345.7)
10	Incremental Wind Excluded from Fuel Filing - Beech Ridge & Grand Ridge	(3,042.4)	(3,158.2)	(3,709.8)	(3,581.2)	(3,460.0)	(3,304.4)	(2,363.3)	(1,843.4)	(1,345.2)	(1,215.6)	(1,616.8)	(2,425.2)	(31,065.6)
11	75% of Off-System Sales Margin Credit	(1,367.2)	(2,953.2)	(2,299.7)	(2,287.9)	34.8	(1,191.3)	(1,909.3)	(1,698.9)	(5,426.4)	(5,023.1)	(3,799.4)	(927.8)	(28,849.3)
12	100% of Incremental Transmission Line Loss Margins	(656.3)	(698.0)	(839.5)	(821.3)	(556.9)	1,382.6	(505.7)	(607.5)	(1,134.8)	(932.9)	(723.1)	(618.1)	(6,711.5)
13	PJM LSE Transmission Losses	1,485.0	1,600.0	1,830.0	1,680.0	1,685.0	1,290.0	1,580.0	1,645.0	1,530.0	1,625.0	1,280.0	1,255.0	18,485.0
14	FTR Revenues	(2,773.9)	(3,344.6)	(3,616.8)	(3,243.8)	(2,933.8)	(2,410.1)	(2,503.1)	(2,773.4)	(3,124.4)	(3,020.7)	(2,580.1)	(2,532.2)	(34,857.0)
15	PJM Implicit Congestion Charges	2,190.0	2,415.0	2,150.0	2,025.0	1,685.0	1,705.0	1,840.0	2,035.0	2,000.0	1,720.0	1,710.0	1,885.0	23,360.0
16	Includable Cost	50,494.1	56,058.9	64,637.9	58,392.7	59,253.0	47,814.5	41,133.1	43,576.9	46,415.3	45,189.8	37,280.2	42,117.9	592,364.4

Line No.	Net Energy Requirement (GWH)	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	12 Mos. Ending 10/31/2022
17	Fossil Generation	2,206.4	3,129.5	3,070.7	2,629.0	1,470.5	1,186.4	1,964.0	2,288.1	3,104.5	3,170.6	2,682.9	1,955.1	28,857.8
18	Hydro Generation	52.8	59.7	68.4	72.5	75.2	82.8	68.2	48.8	27.0	28.1	28.0	33.7	645.3
19	Total Generation	2,259.2	3,189.2	3,139.1	2,701.5	1,545.7	1,269.2	2,032.2	2,336.9	3,131.5	3,198.7	2,711.0	1,988.9	29,503.1
20	Plus:													
21	Purchases	442.5	289.7	410.2	425.7	1,027.6	832.4	542.6	341.9	225.7	188.9	185.2	437.5	5,350.0
22	Purchases - Wind - Camp Grove, Fowler Ridge, & Bluff Point	88.0	90.2	94.0	79.6	86.7	85.6	66.4	48.4	32.3	32.3	45.8	76.8	826.1
23	Purchases - Wind - Beech Ridge & Grand Ridge	51.7	49.4	56.6	51.4	58.6	54.9	40.0	30.7	20.4	18.2	26.5	42.6	501.1
24	PJM Marginal Losses	62.2	72.8	78.3	69.1	65.7	54.7	55.2	58.4	66.6	66.1	57.2	56.3	762.6
25	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Less:													
27	Energy Purchased and Generated for Off-System Sales	299.1	649.2	486.4	433.1	40.3	3.7	432.3	391.4	699.2	764.7	649.3	241.8	5,090.4
28	Total Net Energy Requirement	2,604.5	3,042.0	3,291.9	2,894.2	2,744.1	2,293.2	2,304.0	2,425.0	2,777.4	2,739.5	2,376.3	2,360.3	31,852.4
29	Net Energy Cost (m/kwh)	19.39	18.43	19.64	20.18	21.59	20.85	17.85	17.97	16.71	16.50	15.69	17.84	18.60

CERTIFICATE OF SERVICE

I hereby certify that on this 14th day of September 2021 a true copy of the foregoing Application of Appalachian Power Company was delivered by hand or electronic mail to the following:

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