

**PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON**

Case No. 24-0854-E-42T

**APPALACHIAN POWER COMPANY
and WHEELING POWER COMPANY**

**COMMISSION ORDER ON THE TARIFF FILING
OF APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY TO INCREASE RATES.**

August 28, 2025

TABLE OF CONTENTS

I.	BACKGROUND	1
II.	DISCUSSION	4
	A. CAPITAL STRUCTURE, COST OF DEBT, AND RETURN ON EQUITY	4
	1. Capital Structure	4
	2. Cost of Debt.....	6
	3. Return of Equity	7
	B. RATE BASE.....	15
	1. Cash Working Capital	15
	2. Period End Rate Base Adjustment	17
	3. Construction Work in Progress (CWIP) Inclusion in Rate Base	19
	4. Coal Inventory Adjustment	20
	C. NON-RATE BASE REVENUE REQUIREMENT ADJUSTMENTS.....	22
	1. Miscellaneous Adjustments	22
	2. Depreciation and Asset Retirement Obligation (ARO)	23
	3. Stand-Alone Net Operating Loss Carryforward (NOLC).....	24
	4. Parent Company Loss Adjustment (PCLA)	26
	5. Corporate Alternative Minimum Tax (CAMT)	32
	D. OPERATING INCOME AND OPERATING AND MAINTENANCE (O&M) EXPENSES	33
	1. Generation O&M Adjustment.....	33
	2. Distribution O&M Adjustment.....	33
	3. Long-Term Incentive (LW) Compensation.....	34
	4. Severance Costs	35
	E. RATEMAKING MECHANISMS	35
	1. Electric Rate Stabilization Surcharge (ERS)	35
	2. Environmental and New Generation Surcharge (ENG).....	36
	3. Vegetation Management Program (VMP)	36
	F. RATE DESIGN	37
	1. Jurisdictional Cost-of-Service (JCOS).....	37
	a. Allocation Factor Study.....	37
	b. Jurisdictional Allocation-Kingsport.....	37
	c. Generation and Transmission Property Tax Allocation	39
	d. Open Access Transmission Tariff (OATT) Revenue Allocation	41
	2. Class Cost of Service	41
	a. Production Plant Allocation.....	41

b.	Economic Development Rider (EDR) Discounts to Rate Schedule LCP and IP	42
c.	Special Contract Customers A, B, and G Revenue Adjustments	42
d.	Non-Coincident Peak (NCP) vs. Sigma Non-Coincident Peak (SNCP) Allocation of Secondary Distribution Costs	43
e.	Revenue Distribution or Allocation and Rate Design End of Test Year Customer Revenues Adjustment (Statement G, Adjustment 10-OR)	43
f.	Special Contract Base Rate Revenues (Staff Adjustment 8)	44
g.	Rate Design Issues Under Rate Schedules SWS (Sanctuary Worship Service) and GS (General Service)	44
h.	Rate Design - Elimination or Change to 10kW Maximum Demand Limitation in Rate Schedule SGS	45
i.	Removal of Rate Schedule GS Maximum Charge Provision	45
j.	Rate Schedule RS Time-of-Day (TOD) Recommendations	46
k.	Led Lighting	47
l.	Rate Design – Roll-in of MRBC Rates	47
m.	Residential Winter Tail Block	48
3.	Energy Bill Assist Issues	48
a.	Dollar Energy Fund	48
b.	Low-Income Residential Discount Rider	49
4.	Tariff Terms and Conditions	50
a.	Revisions to Tariff Sheet 3-10	50
b.	Removing Tariff Sheets 29-1 and 29-2 (Mitchell Base Rate Surcharge or MBRS)	50
c.	Removing Tariff Sheet 44 (Tax Reform Rider or TRR)	51
d.	Reconnection Charge	51
5.	Net Metering	51
a.	Transition Time for NMS II	51
G.	COGEN/SPP TARIFF	52
III.	FINDINGS OF FACT	53
IV.	CONCLUSIONS OF LAW	62
	ORDER	76
	APPENDIX A:	
	APPENDIX B	

**PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON**

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA
in the City of Charleston on the 28th day of August 2025.

CASE NO. 24-0854-E-42T

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY

Rule 42T tariff filing to increase rates and charges.

COMMISSION ORDER

The Commission approves a revenue requirement increase of \$76.1 million and requires that the current rates remain unchanged pending future refinancing of a significant portion of the Companies investment in generation plants and deferred expenses. The Order provides for a rate mechanism that would result in a future true-up that offsets the increased revenue requirement if the results of the securitized refinancing result in expected decreases in the costs of capital of the Companies.

I. BACKGROUND¹

On November 1, 2024, Appalachian Power Company and Wheeling Power Company (Collectively Companies) filed revised tariff sheets reflecting increased electric rates and charges of approximately \$250.5 million annually (an approximate 14.6 percent increase) for furnishing electricity to approximately 460,921 customers in Boone, Brooke, Cabell, Clay, Fayette, Greenbrier, Jackson, Kanawha, Lincoln, Logan, Marshall, McDowell, Mercer, Mingo, Monroe, Nicholas, Ohio, Putnam, Raleigh, Roane, Summers, Wayne, Wetzel, and Wyoming Counties. The Companies requested an effective date of December 1, 2024, subject to suspension.

In support of its base rate filing, the Companies filed the direct testimony of Aaron D. Walker, Randall R. Short, Kimberley K. Chilcote, Michael S. Small, Michael M. Spaeth, A. Wayne Allen, Jason E. Baker, Dave A. Hodgson, Robert A. Jessee, Karen M. Johnston, Patrick L. Baryenbruch, Timothy S. Lyons, Franz D.

¹ This background section of this order is abbreviated. For a full procedural history of this case, please visit the Commission's web docket.

Messner, Vanessa Yvonne Oren, Rebecca A. Schwarz, John S. Thompson, Jasmine L. Moore, and John J. Scalzo.

On November 12, 2024, the Companies filed a Motion for Protective Treatment seeking protective treatment for certain workpapers filed in support of the direct testimony of Ms. Schwarz and Mr. Baryenbruch. The Companies argued that these documents contain confidential, proprietary, and commercially sensitive information that should be protected as trade secrets.

The West Virginia Energy Users Group (WVEUG), West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia (CSE), SWVA, Inc. (SWVA), Solar Holler, LLC (Solar Holler), and Consumer Advocate Division (CAD) were granted intervenor status on November 21, 2024.² In that same order, the Commission suspended the requested rates through August 28, 2025, and made the Companies respondents in this case.³ The Commission subsequently granted intervenor status to Kroger Co. (Kroger) on December 19, 2024, and to West Virginia Coal Association, Inc. (WVCA) on February 4, 2025.

The Companies filed affidavits of publication, evidencing publication of the notice of filing of this case in newspapers across the service territory were filed on March 28, 2025, and April 15, 2025.

After extensive discovery, parties other than the Companies filed the following direct testimony in this case⁴:

- 1) CAD – Emily S. Medine, Ralph C. Smith, David E. Dismukes, and David J. Garrett;
- 2) CSE – Justin R. Barnes;
- 3) Solar Holler – Daniel Conant;
- 4) WVEUG – Stephen J. Baron; and
- 5) Staff – Geoffery M. Cooke, Terry R. Eads, Roger L. Estep, Philip A. Wright, Charles M. Johnson, James W. Ellars, and Nathan S. Crouch.

The parties participated in continued discovery and, on May 23, 2025, the parties filed the following rebuttal testimony:

² Comm'n Order, Nov. 21, 2024.

³ Id.

⁴ Direct Testimony of Staff and intervenors was filed on April 23, 2025. Solar Holler filed revised direct testimony of Mr. Conant on April 25, 2025. Staff filed revised testimony and exhibits of Mr. Ellars on May 5, 2025.

- 1) Solar Holler – Daniel Conant;
- 2) Kroger – Justin Bieber;
- 3) CAD – Ralph C. Smith and David Dismukes;
- 4) WVEUG – Stephen J. Baron;
- 5) CSE – Justin R. Barnes; and
- 6) Companies – John J. Scalzo⁵, Randall R. Short, A. Wayne Allen, Jason E. Baker, Kimberly K. Chilcote, Dave A. Hodgson, Robert A. Jessee, Karen M. Johnston, Timothy S. Lyons, Fraz D. Messner, Vanessa Y. Oren, Rebecca A. Schwarz, Michael S. Small, Michael M. Spaeth, and John S. Thompson.

On June 12, 2025 and July 2, 2025, the Companies filed affidavits of publication evidencing publication of the notice of hearing.

The Commission held the evidentiary hearing on June 17 and 18, 2025. Initial briefs were filed by the parties on July 17, 2025, and reply briefs were filed on July 28, 2025.

On the evening of the first day of the evidentiary hearing, the Commission held a public comment hearing at which numerous people attended in person and online, and thirty-two people spoke including Delegate Marty Gearhart. In addition to the public comment hearing, the Commission accepted, as usual, public comments in writing. To date, the Commission has received 5,162 letters opposing the rate increase including letters from the Fayette and McDowell County Commissions, Marshall and Raleigh County Schools, the majority of the Charleston City Council, and numerous individual customers. Concerns over the proposed rate increase included limited incomes, the current amount of rates, and the number of times the Companies have filed for rates increases.

The Companies were represented by Kurt L. Krieger, Esq. and Todd M. Swanson, Esq., of Steptoe & Johnson, PLLC, and Keith Fisher, Esq., Senior Counsel for Appalachian Power Company. WVEUG was represented by Derrick P. Williamson, Esq., Barry A. Naum, Esq., Susan J. Riggs, Esq., and Steven W. Lee, Esq., of Spilman Thomas & Battle, PLLC. Solar Holler was represented by David B. Hanna, Esq., of Hanna & Hanna PLLC. SWVA was represented by Charles K. Gould, Esq., of Jenkins Fenstermaker, PLLC. CSE was represented by Emmett Pepper, Esq. of Pepper & Nason, and Melissa Anne Legge, Esq. and Jessamine De Ocampo, Esq. of Earthjustice. The Kroger Co. was represented by Kurt J. Boehm, Esq. of Boehm, Kurtz & Lowry and Kristina Thomas Whiteaker, Esq. of The Grubb Law Group. WVCA was represented by H. Brann Altmeyer, Esq. and Jacob C. Altmeyer, Esq. of Phillips, Gardill, Kaiser & Altmeyer, PLLC.

⁵ The Companies filed corrected rebuttal testimony for Mr. Scalzo on May 30, 2025.

CAD was represented by Bobby Lipscomb, Esq., Robert F. Williams, Esq, John Auville, Esq., and Heather B. Osborn, Esq. Staff was represented by Victoria Wilson, Esq.

II. DISCUSSION

The Commission will address the issues in the order presented by the Companies in their initial brief. For ease of discussion, because most issues are common to both applicants we will refer to the applicants as Companies. We wish to clarify that we have read and considered all positions taken by all parties. When we generally describe issues that were addressed by multiple parties, we may describe the issue as presented by one party but have considered the testimony, arguments and positions of all parties on each issue.

A. CAPITAL STRUCTURE, COST OF DEBT, AND RETURN ON EQUITY

1. Capital Structure:

In its initial brief, the Companies summarized the capital structures and cost rates proposed as follows:

	Companies				Staff				CAD		
	Percent	Cost	Weighted Return		Percent	Cost	Weighted Return		Percent	Cost	Weighted Return
Long-Term Debt	49.71%	4.95%	2.46%		49.68%	4.95%	2.46%		53.38%	4.95%	2.64%
Short-Term Debt	2.62%	5.51%	0.14%		4.11%	4.96%	.20%		2.62%	5.51%	0.14%
Common Equity	47.67%	10.80%	5.15%		46.21%	9.23%	9.25%		44.00%	9.10%	4.00%
Total	100.00%		7.76%		100.0%		6.93%		100.00%		6.79%

The Companies argued that the capital structures proposed by Staff and CAD are arbitrary. Staff supported its proposed capital structure based on a single point in time capital structure at December 31, 2023, as a starting point with certain short-term debt adjustments. The Companies used their balance sheet capital structure as of December 31, 2023, as a starting point but then adjusted for additional equity issued in January 2024. Thus, both the Companies and Staff December 31, 2023, per books balances were adjusted, with Staff including 2023 debt associated with sales of accounts receivable in Virginia and the Companies reaching into January 2024 to pick up an equity infusion in 2024.

The CAD recommended a 44 percent equity capital structure and then a combination of short-term and long-term debt to make up the 56 percent debt portion. CAD supported its capital structure recommendation based on its review of the proxy group of utilities used in its rate of return (ROR) calculation. The CAD witness noted that the average capital structure of the proxy group was 56 percent debt and 44 percent equity. The Companies challenged the CAD recommended

capital structure but did not dispute the CAD representation that the proxy group had a 56 percent debt ratio.

The Companies attempted to discredit the CAD calculation saying that it was based on the AEP capital structure and that CAD incorrectly used a consolidated AEP capital structure to determine its heavy debt capitalization. We do not agree with the Companies on either count. To the extent the AEP consolidated capital structure includes operating companies as well as the parent company, it is representative of the capital structure of an operating utility as opposed to simply a holding corporation. Furthermore, the proxy group of companies that the CAD actually relied on to derive a 44 percent equity ratio are also representative of utilities that provide distribution, transmission and in some cases production of self-produced power supply. Overall, CAD supported its position that a 44 percent equity ratio and 56 percent debt ratio was a reasonable capital structure.

Commission Decision

We have noted in previous base rate cases that because the cost rate authorized for equity capital is usually higher than the cost of a utility's debt, the ratio of debt and equity to total capital (capital structure) is often an issue in rate cases involving ROR.⁶ The Commission has historically used a variety of techniques, and its judgment and experience, to determine a reasonable capital structure. Depending on economic or other circumstances, the Commission may review various historical, projected, and hypothetical capital structures. The Commission determines a capital structure that (i) is reasonable, (ii) fairly balances the interests of current and future customers, the general interests of the State's economy and the interests of the utilities and (iii) produces the lowest reasonable overall revenue requirement that maintains financial integrity and flexibility for the utility.⁷ While it might appear that a heavily leveraged capital structure (high percentage of debt) is preferred, the Commission considers the end result of an over-leveraged capital, such as low-interest coverage, to arrive at a reasonable capital structure that is neither overly leveraged with debt nor overloaded on the equity side. While parties to rate cases often rely heavily on the actual capital structure of a utility at a point in time or over a restricted time frame, such reliance does not reasonably consider the changes in capital structure over time or the danger of over or under-leveraged capital structure.⁸

⁶ West Virginia-American Water Company, Case Nos. 23-0383-W-42T and 23-0384-S-42T, Comm'n Order, February 23, 2024 at 19.

⁷ Id. at 20.

⁸ Id.

The Companies rebuttal and arguments do not successfully rebut the proposed capital structure used by CAD. The 56 percent debt and 44 percent equity are not out of line with the group of utilities reviewed by the CAD. We acknowledge that the Commission has used actual capital structures in the past, including point in time capital structures, adjusted point in time capital structures, and average capital structures. However, the capital structure determination is not simple arithmetic or a simple science that must take the point in time or the average actual capital structure and accept that as being reasonable. The capital structure is an important component of the revenue requirements in a base rate case, or any rate case which includes a rate of return on capital investment.

A lower equity capital structure will produce a lower overall rate of return. This is due to the fact that cost of debt capital is usually lower than equity and, even more importantly, because the return required to cover interest on debt is not subject to income taxes because interest is allowed as a deduction to arrive at taxable income. Therefore, the lower equity ratio will be beneficial for customers unless it gets so low as to restrict the ability of a utility to acquire debt at reasonable rates. AEP is in control of the Companies' capital structure and can make equity infusions into the utilities at any time to increase the equity percentage in the capital structure. Using a point in time capital structure makes this capability of the utilities particularly problematic and something that the Commission must carefully evaluate when it determines an appropriate capital structure. In this case the record supports the 44 percent equity ratio recommended by the CAD. The use of the 44 percent based on the group of utilities reviewed by the CAD is reasonable and representative of the capital structure of those utilities. Moreover, the end result calculations presented by Staff demonstrate that the financial health of the Companies would not be impaired by a 44 percent equity capital ratio at the cost rates of debt and equity adopted herein. We determined that the Companies did not successfully rebut the position taken by the CAD witness and we will therefore adopt the capital structure proposed by the CAD.

2. Cost of Debt

With regard to the cost of debt there was very little difference between the Staff, CAD and the Companies on their average cost of debt. On a weighted basis the weighted cost of short-term and long-term debt proposed by the Companies and CAD was 4.98 percent. The weighted cost proposed by Staff was 4.95 percent.

Commission Decision

Based on the decision to use the 44 percent equity ratio as discussed *infra*, the dispute regarding adjustments to the actual December 2023 book balances is

academic. However, we will note the Companies' argument that certain debt assignable to Virginia is not consistent with the normal way of determining capital structure. There are many differences in regulatory procedures in Virginia and West Virginia. Our use of expedited recovery mechanisms for business ready sites and broadband expansion may not mirror procedures in Virginia and could give rise to short term debt financing differences. The same could be true for our treatment of investments to upgrade certain power plants or deferrals of storm damage costs or other costs. The different impacts on the need to carry short term debt, if there are any, could vary one way or the other on a state basis. The use of the total company capital does not require a detailed analysis of the reasons for debt levels on a state by state basis. If the Companies wish to propose identification of short term debt or even long term debt in the future, based on differences in operating procedures and regulation in West Virginia and Virginia, they should provide a complete analysis of potential differences, not just the isolated accounts receivable issue. We suggest that such a proposal would add a level of complexity not heretofore found in rate cases.

As the Commission will use a capital structure that is not taken from a point in time or averaged over a specific time as discussed above, we must determine how the 56 percent debt should be factored into the overall rate of return from the standpoint of the cost of debt. We have determined that because there is no single point in time or multiple points in time over which to measure the debt cost and because the proposals by the Companies, the Staff, and the CAD all reflect the cost of debt of the Companies over various periods of time, we shall average the weighted cost of debt of the three parties and apply that to the 56 percent total debt. That average cost of total debt is 4.97 percent. It is not necessary to divide the interest cost between long-term debt and short-term debt because we are using the weighted cost of long-term and short-term and applying it to the 56 percent debt component of the capital structure.

3. Return on Equity

Determining a fair and reasonable return on equity is not a formulistic scientific exercise. While the witnesses presented detailed models based on economic conditions and results over the years applied to the utility industry, the final determination is the Commission's decision, bound by evidence, current economic conditions, and the legal precedents:

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and

uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.

The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.⁹

and

From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. [citation omitted] By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.¹⁰

While it is sometimes argued that the Commission must address and adopt the mathematical formulae of expert witnesses, that is far from the truth. As stated by the Supreme Court, in the above cited Hope case:

Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed, which is controlling. It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end.¹¹

The Act referred to by the Supreme Court is identical with regard to "just and reasonable", to the West Virginia Code which delegates authority and jurisdiction to the Commission.

⁹ Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of West Virginia 262 U.S. 679, 692-93 (1923).

¹⁰ Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

¹¹ Id. at 602.

As acknowledged by the Companies in their initial brief, the Commission has stated more than once that there is no absolute, correct answer when it comes to determining a utility's return on equity. Establishing a "fair ROE result lies within a zone of reasonableness that is framed by the evidence, including the testimony and exhibits of various witnesses."¹²

We will consider all of the evidence and be guided by the data, but in the end, the ROE will be the judgement of the Commission and our evaluation of the impact of the ROE included in rates on the financial condition of the Companies.

The ROEs recommended by the witnesses in this case are: Companies - 10.5 percent; Staff - 9.25 percent; and CAD - 9.1 percent.

The Companies witness Thompson used several methods including the discounted cash flow (DCF) analysis, capital asset pricing model (CAPM), and utility risk premium.¹³ In his direct testimony, he concluded that a range of 10.3 percent to 11.3 percent was reasonable and, choosing the midpoint of that range, he recommended a ROE of 10.8 percent. Subsequently, in his rebuttal testimony, he modified his range to between 10.0 percent to 11.0 percent and changed his recommended ROE to 10.5 percent.

Mr. Thompson's original DCF analysis was based on a yield of 4.1 percent derived from stock prices over a thirty-day trading period ending April 15, 2024. After adding expected growth rates for nineteen proxy utilities from four different sources he arrived at the yield plus growth indicated ROE as follows:

Value Line	IBES	Zacks	br + sv	Average
9.80%	9.86%	9.78%	9.28%	9.68%

After excluding two data points (4.9 percent and 5.7 percent), which he considered low outliers, he arrived at his initial DCF range and average as follows:

Value Line	IBES	Zacks	br + sv	Average
10.09%	9.86%	10.04%	9.28%	9.82%

¹² Appalachian Power Co. and Wheeling Power Co., Case Nos. 14-1151-E-D and 14-1152-E-42T, Comm'n Order, May 26, 2015, at 16. Companies' Initial Brief at 6, July 17, 2025.

¹³ Cos. Exh. JST-D, Bates 4691-714.

In his rebuttal testimony he indicated that he had reviewed the DCF data in response to criticism in other parties' direct. His revised DCF numbers were:

Value Line	IBES	Zacks	br + sv	Average
9.6%	10.5%	10.4%	9.0%	9.9%

For his CAPM analysis Mr. Thompson used an unusual approach based on a projected expected market yield of 12 percent. He used a thirty-year treasury bond yield of 4.5 percent based on bonds issued for the six month period ending March 2024. He then applied a relatively high Beta for the nineteen companies in his proxy group to arrive at his view of a CAPM supported ROE of 11.4 percent. He did not use that value, however, assuming that it was too low. He applied a size adjustment factor to increase the CAPM indicated ROE to 11.7 percent.

For his Risk Premium he determined that the average Risk Premium over his study period was 3.89 percent. He did not use that value, but we note that the 3.89 percent, if added to his 5.98 percent Baa utility bond yield base would total to an indicated Risk Premium ROE of 9.87 percent. Instead, he adjusted the Risk Premium to 4.74 percent, based on what he described as a Risk Premium to Interest rate relationship to add 85 basis points to the 9.87 percent, to arrive at a total indicated ROE of 10.72 percent.

CAD witness Garrett recommended a ROE of 9.1 percent based on DCF and CAPM analysis.¹⁴ For his DCF analysis he used the same proxy group of 19 companies that the Companies witness had used. He used a different time frame for stock prices, that being thirty trading days ending April 16, 2025, and arrived at an average yield of 3.4 percent. This was 700 basis points below the yield derived by Mr. Thompson using a 2024 30-day trading period. That difference alone, if applied in Mr. Thompson's model, would result in an indicated DCF of around 9 percent.

Mr. Garrett did not use the projected growth rates used by Mr. Thompson. He instead relied on projected growth rates from Value Line to arrive at a 5.4 percent growth rate. Although he testified extensively that a sustainable growth rate should be used in the DCF model, and he quantified a sustainable growth rate of 3.7 percent, he nevertheless used the Value Line growth rate of 5.4 percent, which, when added to his derived dividend yield of 3.4 percent, resulted in a DCF indicated ROE of 9.1 percent. If he had used his sustainable growth rate for his recommendation, the indicated ROE would have been 7.3 percent.

¹⁴ CAD Exh. DJG-D at Bates 699.

In his CAPM analysis, Mr. Garrett derived a risk-free yield of 4.63 percent. This was based on yields on 30-year treasuries, but for a different period than that used by Mr. Thompson and was higher than Mr. Thompson's risk-free yield of 4.5 percent. Applying the market premium to the risk-free component, he testified that the CAPM result was 9.1 percent. Our review of Mr. Garrett's CAPM data seems to indicate an error in his 9.1 percent, which it seems should be a CAPM indicated ROE of 9.7 percent.

Staff witness Estep also used a DCF and CAPM model. Staff used a slightly different sample group for its DCF model based on a group where the selected utilities had a heavier weighting of regulated business.

The yield in the Staff model (based on average daily stock closing price for the 13 week period from January 20, 2025, to April 18, 2025 and projected next 12 months' dividend per Value Line Investment Survey, April 25, 2025), was 3.68 percent.¹⁵

Staff used a number of sources to obtain growth rates for its DCF calculations. These included historical growth rates in dividends and earnings from Value Line, and projected earnings per share from Zacks and Morningstar.¹⁶ Before outlier removal the initial growth rates for the entire sample group ranged from average historical dividends and earnings growth from Value Line of 4.77 percent to projected earnings growth of 5.16 percent, with an overall average of 5.01 percent. After outlier removal, Staff witness Estep derived an average growth rate of 5.5 percent.

The final DCF indicated ROE recommended by Staff was the sum of the indicated 3.68 percent yield and outlier adjusted 5.5 percent growth, or 9.18 percent.

For his CAPM, Mr. Estep used a market return of 8.44 percent and an average beta of .62, for a return component above a risk-free investment of 5.24 percent. He added a 3.36 percent risk-free rate based on a historical average of three-month treasury bills to arrive at CAPM indicated ROE of 8.6 percent.

Although the average of the CAPM and DCF indicated ROEs is 8.9 percent, Mr. Estep did not recommend the average or even the higher DCF value of 9.18 percent. He recommended that the ROE in this proceeding be set at 9.25 percent, which is the same ROE last approved by the Commission in Case No 23-0298-E-P.

¹⁵ Staff Exh. RLE-D at Bates 214.

¹⁶ Id. at Bates 215.

The rebuttal to Mr. Estep's recommendation filed by Mr. Thompson was that the growth rate in the Staff DCF included both earnings and dividend growth rates. He argued that the Commission's prior use of both earnings growth and actual historical dividend growth is wrong because "[G]rowth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations... The availability of projected EPS growth rates also is key to investors relying upon this measure as compared to future trends in DPS... The fact that analyst EPS growth estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a primary basis for their expectations."¹⁷

He also objected to the removal of high outliers that exceeded 300 basis points above the average indicated ROE. Mr. Thompson did not object to the Staff removal of low outliers that were below 5.65 percent, which is the effective cost of long-term debt. However, he criticized the Staff for eliminating outlier ROE results that were 300 basis points above and below the average indicated ROE.

Mr. Thompson also stated that the CAPM used by Mr. Estep was wrong because it included two sources, Value Line and Zacks, for the beta factor whereas in prior cases, Staff used only Value Line betas. He argued that "Staff justifies this change as an effort 'to expand its models to reflect a wider range of investor's expectations,' but it has the effect of lowering Staff's average beta value from 0.78 (Value Line) to 0.62 (average of Value Line 8 and Zacks)."¹⁸ He further objected to the use of Zacks beta values for two reasons. First, he maintains that Value Line is "the largest and most widely circulated independent investment advisory service."¹⁹ Secondly, he argued that "the methodology used to calculate Value Line betas is completely transparent, and accordingly it is known to investors. Value Line computes their beta values using weekly stock returns relative to weekly returns for the NYSE dating back five years, and as was just discussed, they are also Blume adjusted."²⁰ In contrast, little is known about how Zacks calculates their betas, other than apparently they are calculated in reference to the S&P 500 Index over a five-year period."²¹

¹⁷ Cos. Exh. JST-R at Bates 341-342.

¹⁸ Id. at Bates 348.

¹⁹ Id. at Bates 349.

²⁰ Id. at Bates 350.

²¹ Id.

As a second criticism of Staff's CAPM, Mr. Thompson took exception to the use of the three-month T-bills as the risk-free component of the CAPM. He argued that thirty-year government bonds are the preferred risk-free factor to include in the CAPM model.

Commission Decision

The recommendations of expert witnesses on cost of common equity are useful as guides, but that the determination of an appropriate cost of common equity for a utility must rest principally with the best judgment of the Commission.²² The data that underlie the recommendations of ROE witnesses must be evaluated and judged carefully and practically, based on our judgment of the methods used by the expert witnesses, the data presented by those witnesses and the current market conditions. There is no absolute, correct answer with regard to ROE even though the determination of a reasonable ROE involves calculations on a mass of data presented by expert witnesses. The fair ROE result lies within a zone of reasonableness that is framed by the evidence, including the testimony and exhibits of the various witnesses. The final determination of ROE, however, rests with the Commission based on our judgment and the application of regulatory principles and policies that have been used by this Commission.²³

We will focus on the DCF and CAPM models to consider the data presented by the parties and formulate our own judgement regarding a fair ROE that meets the Hope and Bluefield tests and satisfies our responsibility to balance the interests of the utility, the customers and the economy of the state. We note that although the Risk Premium has been presented by the Companies in this case and has been presented by others in prior cases, it is not a primary model that has been adopted by this Commission. In fact, we note that the FERC, which had used the Risk Premium analysis in the past, recently abandoned it, stating:

Specifically, we find that the record does not contain any evidence suggesting that investors use the Risk Premium model adopted in Opinion No. 569-A. We also find that the record does not contain any evidence that would resolve the circularity concerns inherent in the Risk Premium model adopted in Opinion No. 569-A. Accordingly, we reverse the portions of Opinion Nos. 569-A and 569-

²² See, West Virginia-American Water Co., Case No. 10-0920-W-42T, Comm'n Order at 18 (Apr. 18, 2011).

²³ Id.

B that include the Risk Premium model in the Commission's ROE methodology.²⁴

From the DCF data presented in this case which cover different periods of time for the critical yield calculation, we have a yield component of 4.1 percent from the Companies witness, based on 2024 stock price data, 3.4 percent, based on April 2025 data presented by the CAD witness, and 3.7 percent, based on stock prices over a thirteen week period ending in April 2025 presented by Staff's witness. Clearly none of these numbers is mathematically incorrect because they represent actual dividends divided by actual stock prices. Yet, they are significantly different.

Applied to Mr. Thompson's growth rate of approximately 5.7 percent, his one month in 2024 stock price determined yield of 4.1 percent equals a DCF indicated ROE of 9.8 percent ($4.1 + 5.7$). But using the more recent 2025 yields used by CAD, applying the Companies' growth rate results in a DCF indicated ROE of 9.1 percent ($3.4 + 5.7$). Using the 2025 yields calculated by Staff over a longer period of time, the indicated ROE at the 5.7 percent growth rate would be 9.4 percent ($3.7 + 5.7$).

Changing nothing more than the yield based on actual dividends and actual stock prices but using stock prices from different periods of time in 2024 and 2025 and using the Companies' proposed growth rate changes the DCF indicated ROE from 9.8 percent to either 9.4 percent or 9.1 percent. Considering that these results can be further changed, depending on the more controversial growth rates which are not known except for the historical dividend growth rate, which Mr. Thompson criticizes, emphasizes why there is no single correct answer or mathematically precise ROE.

We also do not agree that some of the low end numbers in the Staff or CAD data are unrealistic. The purposes of ranges are to fix a low end and a high end. Just because the low end is not to the Companies' liking does not mean that the underlying data is wrong. We note that in the above cited FERC 2024 Order reducing the ROE for transmission companies in MISO from over 12 percent to 9.98 percent, the FERC accepted DCF numbers that created a low end beginning at 6.97 percent. Its CAPM data created a low end beginning at 7.8 percent. The FERC also had high end range limiters of 12.07 and 13.09 percent for DCF and CAPM, respectively. The FERC picked a midpoint of 9.98 percent. Our point is that ranges can vary widely. The FERC accepted a wide range and did not

²⁴ Association of Businesses Advocating Tariff Equality v. Midcontinent Independent System Operator, Inc., 189 FERC ¶ 61,036 (Order on Remand), October 17, 2024.

eliminate the low end DCF result of 6.97 percent or the CAPM 7.8 percent because they were unrealistic.

We determine that consideration of all of the evidence and the ranges presented by the data introduced in this case justifies continuation of the existing 9.25 percent ROE is justified.²⁵

While utilities often criticize Commission review of the end result of any given ROE recommendation, it is important to be sure that the disparate ROE results do not result in indicators of financial health, such as interest coverage or cash flow relative to dividends, to fall into a questionable area for the financial health of the utility. We disagree with criticism of end result analysis. It is not a means to an end or a circular mathematical exercise as some of the naysayers have said in the past. It is a test of reasonableness of any particular ROE result as far as satisfying the requirement that the return is sufficient to assure confidence in the financial soundness of the utility as required by the Bluefield and Hope cases.

Staff witness Estep's end result analysis showed that the coverage of interest ranges remains well above 2.5 times at his recommended 9.25 percent ROE and even at a low end 8.3 percent ROE. His calculations show reasonable retained earnings after payment of dividends and reasonable internal cash flow to fund capital additions. These percentages will change as a result of our decision to use a 44 percent equity ratio, but the change will be to acceptable levels. We find that maintaining the 9.25 percent ROE is supported by a complete evaluation of all of the DCF and CAPM data presented ably by the expert witnesses as we apply our judgement to those data to arrive at a reasonable ROE to approve in this case.

B. RATE BASE

1. Cash Working Capital

The Companies objected to the exclusion of depreciation and profit (return on equity/dividends) from the calculation of cash working capital. However, there was no rebuttal filed to the Staff exclusion of depreciation and profit (return on equity/dividends) from the cash working capital calculation.

The Commission has historically explained that the cash working capital allowance recognizes that a company must pay cash for expenditures when the bills come due although it may not collect revenue from customers to cover those expenditures until after the bills come due. Our rules provide for inclusion of a

²⁵ Docket Nos. EL14-12-016 et. al. FERC Order on Remand October 17, 2024.

working cash allowance, if justified by a cash working capital study.²⁶ Cash to pay employees, or vendors, or taxing authorities represents real cash that a utility must pay when those bills come due. The utility does not need to pay real cash when depreciation comes due.

We note that the FERC does not prescribe rules for a cash working capital study for electric utilities although it does allow for the filing of a study or formula. FERC explains in its natural gas pipeline rules what is included in cash working capital. There, the FERC rule provides:

Schedule E-1. Show the computation of cash working capital claimed as an adjustment to the gas company rate base. Any adjustment to rate base requested must be based on a fully-developed and reliable lead-lag study. The components of the lead-lag study must include actual total company revenues, purchased gas costs, storage expense, transportation and compression of gas by others, salaries and wages, administrative and general expenses, income taxes payable, taxes other than income taxes, and any other operating and maintenance expenses for the base period. Cash working capital allowances in the form of additions to rate base may not exceed one-eighth of the annual operating expenses, as adjusted, net of non-cash items.²⁷

The FERC Rule is similar to ours in that it describes cash expenses and taxes as components in a lead-lag study and does not list non-cash depreciation or earnings and dividends which are not expenses requiring cash working capital.

The Companies point out in their initial brief that the Commission allowed depreciation in the cash working capital calculation in their 2014 rate case. The facts and circumstances leading to such a determination were the basis for the Commission decision at that time. The Commission decides each case based on the facts and circumstances applicable at the time a decision is made. The West Virginia Supreme Court has held in The Chesapeake and Potomac Telephone Companies of West Virginia v. Public Service Commission of West Virginia, 300 S.E.2d 607,613 (1982):

[I]t is generally recognized that the doctrine of stare decisis does not normally apply to administrative decisions. As Professor Davis states in his respected treatise:

²⁶ Rule 20.4.7, Rules for the Construction and Filing of Tariffs, 150 C.S.R. 2.

²⁷ 18 C.F.R. §154.312e(1).

When the purpose is one of regulatory action, as distinguished from merely applying law or policy to past facts, an agency must at all times be free to take such steps as may be proper in the circumstances, irrespective of the past decisions Even when conditions remain the same, the administrative understanding of those conditions may change, and the agency must be free to act

2 K. Davis, *Administrative Law* 3 18.09 (1958) (footnotes omitted.) Accord, *State v. Alabama Public Service Commission*, 293 Ala. 553, 307 So.2d 521 (1975); *Rumney v. Public Utilities Commissioner*, 172 Colo. 314, 472 P.2d 149 (1970). The Commission's decisions in previous cases therefore do not preclude it from reaching an opposite result in this case.

We do not find justification in this case to include depreciation or profits on rate base as cash working capital. We will adjust cash working capital to reflect only the expense payment leads and revenue lags consistent with the cash expenditures for O&M expenses and taxes included in the final revenue requirements approved in this Order.

2. Period End Rate Base Adjustment

The Companies filed a test year rate case with an average rate base and test year revenue and expense determinants, adjusted for known and measurable changes in the revenue or cost rates applicable to those factors. The Companies proposed a series of adjustments to adjust the average rate base balances to December 31, 2023, end-of-year rate base.²⁸

The CAD opposed the departure from an average test year rate base. CAD witness Smith cited previous cases where the Commission has departed from an average rate base but maintained that those instances presented unique circumstances and should not apply in this case.

The Staff also opposed the departure from an average rate base.

WVEUG did not provide a witness to support a particular test year but supported the lower revenue requirements in toto as recommended by CAD and Staff.

²⁸ Cos. Exh. KMJ-D at 19-21 (Bates 4280-82).

CSE did not address the total year end rate base issue. However, it did point out that a portion of the plant that was included in the Companies adjustment and represented to be plant placed in service by December 31, 2024, had not actually been placed in service. Based on that, it argued that the generation component of the year end adjustment made by the Companies should be reduced by \$3.1 million.

The Commission has allowed the Companies to implement many special surcharges to reflect plant additions taking place not only in a rate case test year, but in non-rate case years. These adjustments tend to allow plant investments that are in addition to the average rate base in a base rate case to be periodically adjusted and to allow a return to the Companies on these investments after a base rate case. We will roll into base rates all investment and expenses made in those special surcharge cases (except for the Business Ready Sites Program surcharge which will be addressed in Case No. 24-0956-E-IDS) as presented in the most recent surcharge filings. There will also be a final true-up to allow recovery of any under recovery or credits for any over recovery if the amounts rolled into base rates did not provide for a true-up. We allow that investment and true-up because we were either statutorily required to allow expedited rate treatment of certain investments in plant, or because we encouraged or required investments on grounds that they were in the best interests of customers. We allowed rate base treatment until further order of the Commission and will not remove that part of our commitment until the investments are fully rolled into the Companies' base rates.²⁹

Other investments, however, have not generally been afforded or promised end-of-year or projected treatment in rate base in a base rate case to avoid conflict with the matching principal that we believe is inherent in the use of an average test year rate base. Investments in plant placed into service during a test year will reflect any offsetting revenue produced from those investments or expense reductions produced from those investments. That is the basis for an average test year adjusted only for known and measurable changes in expense rates and not units. The principal is called the matching principal. It may not be perfect, and there have been instances when we departed from a strict adherence to the matching principal. But that does not bind us to always depart from the principal. Except for specific categories of investment as discussed herein, we do not find evidence or a compelling reason to depart from the average rate base in this case.

²⁹ There may be some investment related to statutory or Commission-approved surcharge cases that were not included in the related cases now before us. We are authorizing the Companies to roll investment through August 28, 2025 into base rates, eliminate surcharges and design base rates accordingly. We will, however, review those investments in the final true-up of the surcharge cases and require the Companies to provide adequate proof that they were not duplicative, were consistent with the purpose of the surcharge case and were prudently incurred reasonable and necessary investments.

3. Construction Work In Progress (CWIP) Inclusion in Rate Base

The Companies originally proposed a rate base adjustment to include \$239 million in construction work completed and in service prior to January 1, 2025. The adjustment included production, transmission and distribution plant. For the most part there is no difference between these adjustments and the request to depart from an average test year. We see no reason to completely violate the matching principal discussed earlier by making the total adjustments requested by the Companies. It is not clear if any of the distribution or transmission CWIP includes projects that we described in the penultimate paragraph above as being included in special surcharge cases. To the extent they are, although we will not allow the total requested CWIP adjustment, we will allow continuing recovery through the base rates or surcharge mechanism, including a true up that will be required after the rates in this case go into effect. The investment recoverable through the discontinued surcharge cases will be rolled into base rates at the level of those investments as of August 28, 2025.

There is a new circumstance to consider, however, regarding investments in the coal fired generation plants of the Companies. The Legislature recently passed into law³⁰ requirements that utilities to be prepared to maximize production from their generating plants when self-generation will result in reduced energy costs for West Virginia ratepayers,³¹ and to analyze actions necessary to extend the life of each generating unit.³² The new law further requires the Commission to determine the extent to which the electric generating units in the state were being maintained be able to achieve at least a 69 percent capacity factor.³³ We are in the process of gathering information on the practices and procedures of the utilities to achieve the goals set by the new legislation, and will soon be considering integrated resource plans describing how the upkeep, upgrades, maintenance, and investments in those plants are consistent with the goals set for coal fired generation plants. While the Companies' generation plants are aging, upgrades and proper maintenance can keep them operating at the levels needed to provide reliable, dispatchable power supply that, in our Regional Transmission and market area, is becoming an even more critical need than in the past. We believe that in light of the goals which we have set, and now the legislature has set, to maintain the valuable resources that the base load, on-site inventoried fuel secure, dispatchable, coal fired generation plants represent, it is appropriate to depart from

³⁰ House Bill 2014, 2025 Regular Session of the West Virginia Legislature.

³¹ W. Va. Code §24-2-1d(f).

³² W. Va. Code §24-2-19(e).

³³ W. Va. Code §24-2-1d(f).

the average rate base matching principal for the requested generation plant investments.

The Companies requested an adjustment to correct an error regarding broadband investment and to exclude CWIP that was estimated to go into service before January 1, 2025, but which missed that in-service date. In consideration of the increased importance of the coal fired plants both for economic and reliability reasons, the Commission will allow the originally requested adjustment for CWIP investment in projects that were under construction in late 2024 and were not likely to be cancelled. The Commission will include the CWIP request for the power plants included in the original Companies request.

4. Coal Inventory Adjustment

The Companies proposed a coal inventory adjustment that adjusts rate base upward by the difference between the average levels of inventory in the average test year and the projected cost at the end of 2025. The rate base adjustment is \$10.1 million. The Companies also are raising their coal inventory target for their plants to 35 days.

CAD witness Medine testified that the higher coal inventories might be reasonable if the coal plants were regularly operating at or near their full load capacity for extended periods. She further testified that having a surplus of coal on site would provide a reasonable market hedge if the Companies experienced unexpected supply chain interruptions or unforeseen market price swings. She recommended that the Companies need to monitor markets carefully to ensure no disruptions are expected that would affect the supply.

With regard to the level of coal inventory proposed by the Companies, Ms. Medine opposed inclusion in rate base. Instead, she supported CAD witness Smith's proposal that the coal inventory be limited to the maximum coal burn quantities at each plant for consecutive 35-day periods during the review period.

Ms. Medine proposed her own adjustment to the inventory values based on her position that the imprudent actions of the Companies caused the high prices

	Purchase Price (\$/Ton)				Recommended \$/Ton	
	2021	2022	2023	2024		
Amos LS	\$ 62.92	\$ 83.06	\$ 114.78	\$ 112.11	Amos LS	\$ 97.26
Amos HS	\$ 44.59	\$ 57.30	\$ 66.15	\$ 80.72	Amos HS	\$ 64.44
Mitchell LS	\$ 68.44	\$ 92.43	\$ 127.57	\$ 118.30	Mitchell LS	\$ 105.94
Mitchell HS	\$ 40.92	\$ 40.53	\$ 76.08	\$ 60.08	Mitchell HS	\$ 57.14
Mountaineer	\$ 42.20	\$ 67.41	\$ 72.46	\$ 77.20	Mountaineer	\$ 66.82
Source: EIA Form 923						

that they had to contract for when they found themselves running out of coal. She testified that the projected per ton coal costs at the various inventory stockpiles should be adjusted as shown in the chart below.

Ms. Medine also recommended changes in the reflection of coal inventories in rate base, changes in coal purchasing practices and changes in reporting the volumes of coal from a tonnage basis to a btu basis.³⁴

The Staff also opposed the inventory adjustment.

The Commission is concerned with the high inventory level, but for different reasons from the CAD and Staff. We have told the Companies for several years now that they should strive to achieve a 69 percent capacity factor when it is economical to do so. Now they are subject to a statute that requires the 69 percent capacity factor target.³⁵ Yet, the Companies are not running their plants at desired capacity factors and as a result have an excessive coal inventory. We do not oppose the high inventory level for the same reasons implicit in the Staff and CAD opposition. Our concern is that the inventory can be reduced by running the plants more. Maybe the plants are not capable of running at the expected capacity factor. If that is the case, then the Companies should be forthcoming and provide a truthful and objective evaluation of how to fix that problem. Our concern is that we continuously hear from the Companies that they are subject to bid-based economic dispatch by PJM and have no choice but to operate only at the times and levels that PJM authorizes. We do not believe that is the case based on our understanding of PJM Market Rules which state:

Generation resources, regardless of fuel type, fall into one of two categories, Capacity Resources or Energy Resources. If available, all Generation Capacity Resources that have a Reliability Pricing Model (RPM) or Fixed Resource Requirement (FRR) Commitment must submit offer data into the Day-ahead Market and may elect either to Self-Schedule or offer the resource to PJM for scheduling as a PJM RTO-Scheduled Resource.³⁶

³⁴ See generally, CAD Exh. EMS-D.

³⁵ W. Va. Code 24-2-1d(f) provides, "The commission shall require the utilities to maintain their thermal baseload generating units in a manner to allow them to be able to self-generate and achieve at least a sixty-nine percent capacity factor. Nothing herein shall require a utility to operate a generating unit at a sixty-nine percent capacity if doing so will cause an increase in the charge or charges for electric energy over and above the establishes and published tariff, rate, joint rate, charge, toll or schedule."

³⁶ PJM Manual 11: Energy & Ancillary Services Market Operations, Sec. 1: Overview of energy & Ancillary Services Market Operations, p. 11.

If we misunderstand the flexibility for FRR Companies in PJM, to self-schedule so that they can control their own generation, we expect the Companies to explain self-scheduling in the next ENEC proceeding. We are not saying that self-scheduling regardless of the economics is required, or even wise in all circumstances, however, we believe that the Companies can consider factors such as the cost of carrying and maintaining excessive coal inventories, the need to reduce excessive coal inventory levels, the economics of eliminating excess high cost coal from inventories to make room for more economical new coal contracts, and the wear and tear on equipment caused by running at low loading and excessive ramping from low loads to higher loads and back down. Reasonable exercise of the PJM self-dispatch flexibility is a required element of prudence. The Companies have that flexibility yet we continue to hear from witnesses that they do not, or are directed to operate the plants as if they do not. The Companies are not slaves to PJM dispatch and we expect them to operate accordingly.

We expect the Companies to maximize the use of their generation plants by scheduling plants when they believe that reasonably scheduled output over each daily scheduling period will not produce a significant out-of-pocket net loss based on only the truly variable costs of generation that are directly proportionate to output. They may run at a loss in the hours immediately before and after midnight so that they will be able to ramp up plants quickly as market prices rise in the morning and evening hours. However, that expectation does not lead us to the conclusion that high inventories will suddenly disappear. We will not require the downward adjustments to inventory recommended by CAD and Staff. Moreover, we do not agree that a 35-day inventory is the maximum that should be targeted. There must be some headroom for inventory to cycle up during periods of low usage, low market prices and plant downtime for both planned and unplanned maintenance and cycle down during high market price periods.

C. NON-RATE BASE REVENUE REQUIREMENT ADJUSTMENTS.

1. Miscellaneous Adjustments

In their Initial Brief the Companies grouped three adjustments into this category: Adjustment 43-AG to increase test year capacity performance insurance expense by \$255,893 as a result of increase in insurance premiums following Winter Storm Elliot; Adjustment 31-AG of \$824,080 to amortize and recover rate case expense of over two years; and Adjustment 21-PE to increase power production expense by \$507,123 to amortize the Companies' forecasted excess sulfur dioxide allowances over 15 years.

The Commission will approve Adjustment 43-AG.

We will normalize rate case expense by allowing one-third of the rate case expense in revenue requirements. The Companies should be aware that our normalization adjustment does not authorize it to carry forward an unamortized regulatory asset into future rate case expenses. If the Companies file another rate case in less than three years, the balance of prior rate cases, even if recorded on the books, will not be picked up as a regulatory asset. On the other hand, if the Companies do not file another rate case in three years they will continue to collect the normalization adjustment included in this case without any over-recovery concerns.

We will not include the Adjustment 21-PE power production expense amortization in base rates. The Companies may include the expense as an ENEC expense. The Commission will consider the amount to allow in the next ENEC case. The amount allowed will be considered as part of the ENEC over or under recovery as an ENEC cost beginning in 2025.

2. Depreciation and Asset Retirement Obligation (ARO)

The Companies object to the removal of the ARO adjustment they propose in this proceeding, including the depreciation on ARO assets. The Companies support their argument by pointing out that the ARO adjustments and depreciation have been allowed by the Commission in the past, including their 2014 rate case. In its order in that case the Commission stated:

Mr. Oxley testified that the Companies proposed rate base should be reduced by \$35.640 million for the accumulated ARO accretion expenses recovered in rates through the end of the 2013 test year. . . .

In rebuttal to the Staff positions, Mr. Brubaker did not disagree with Staff's proposal to reduce rate base by the accumulated ARO accretion expense recovered in rates through the end of the test year but did argue that the amount should be limited to the average test year balance of \$33.715 million. . . .

No party objected to the adjustments proposed by the Companies to reduce rate base by the net ARO assets, and the Commission will adopt those adjustments. The Commission also adopts the Staff position to reduce rate base by the accumulated ARO accretion expense recovered in customer rates through the end of the 2013 test year. The Staff reduction of \$35.640 million will be adjusted downward to \$33.715 million to reflect the average test year balance as agreed to by the Companies at hearing. The Commission will not

adopt the Staff position to lower depreciation expense by \$3.105 million for depreciation of the ARO assets. While the net ARO assets should not be recognized for the purposes of return on rate base, the ARO assets should be depreciated over the expected life of the ARO assets to avoid intergenerational issues. That charge should be imposed on the ratepayers who benefit from the service provided by those assets.³⁷

The Commission will allow the adjustments and depreciation for the same reasons expressed in the 2014 rate case order. Further, it appears that the \$33.715 rate base credit was a ratemaking adjustment, and not a bookkeeping adjustment but we cannot determine that a similar adjustment was made in this case. In the next base rate case we expect the Companies to address this rate base credit and explain why it should not be adjusted due to additional payments from customers since the 2014 rate case.

3. Stand-Alone Net Operating Loss Carryforward (NOLC)

This was a hotly contested issue related to the potential for a normalization violation if the Commission did not include the Companies' proposed \$17,732,308 Adjustment 121-ADFIT to create a Deferred Tax Asset or (DTA) to be added to rate base. The Companies argued that the DTA was required in order to prevent the Companies' violation of IRS normalization rules. The Companies attempt to support their position with several Private Letter Rulings (PLRs) issued to other AEP affiliates in other jurisdictions which they claim are on the same issue and will apply to the Companies.

Staff opposed the adjustment and the applicability of the other AEP affiliates PLRs. Staff supported its opposition with a PLR issued to Mountaineer Gas Company when it raised the issue of the necessity of a deferred tax asset in a Net Operating Loss carryforward situation.

The Companies argued in their Initial Brief that the PLR for Mountaineer was "much different in substantive form and format from the AEP PLRs." Moreover, the Companies indicated that if the Commission adopts the Staff recommendation, they "will be forced to request a private letter ruling from the IRS on the NOLC-DTA issue."

The Companies also state that they will file for the PLR "following the substantive format of the AEP PLRs, and not the Mountaineer PLR... That is, the

³⁷ Appalachian Power Co. and Wheeling Power Co., Case No. 14-1152-E-42T, Comm'n Order, May 26, 2015, at 39.

Companies will not agree with the Commission in this case - as Mountaineer seems to have eventually done in the Mountaineer PLR process.”³⁸

Commission Decision

The Commission points out that the Companies’ representation that other AEP subsidiaries’ PLRs are identical to the situation in West Virginia is not supported by any comparison of the West Virginia ratemaking for federal income taxes with that in the jurisdictions within which those affiliates operate. The representation is also not supported by making available to us the explanation presented to the IRS by the affiliates as to why they would face a normalization violation. Furthermore, the record in this case does not indicate whether the regulatory commissions in those states agreed or disagreed with the substance of the request for the ruling, offered their own defense of their federal income tax ratemaking treatment, and were allowed to participate in discussions with the IRS.

The argument that the Mountaineer ruling was “much different in substantive form and format from the AEP PLRs” is not persuasive considering that the Mountaineer request and the IRS ruling were specific to ratemaking in West Virginia rather than in other states where AEP subsidiaries that received the rulings operate.

Finally, the threat that the Companies will not agree with the Commission decision as they presume Mountaineer did assumes a fact that does not exist. Mountaineer did not agree with the Commission and told the IRS when it filed for the PLR that it believed that there was a normalization violation due to the Commission’s ratemaking. The Commission explained otherwise to the IRS, and the PLR agreeing with the Commission speaks for itself.

The Commission will not include the DTA in rate base because whether the utility or its consolidated tax group has a net taxable income or a net taxable loss and tax loss carryforward, our ratemaking does not require the DTA to escape a violation of normalization requirements. We have always intended to, and believe that our ratemaking does comply with normalization rules because we do not flow through the benefits of book/tax timing depreciation differences that are required to be normalized in determining the income tax expense to include in rates. We do not believe that we directly or indirectly flowed through to ratepayers such timing differences that are required to be normalized. To the extent that accelerated depreciation that is required to be normalized by federal statute and IRS regulations is or has been available to the Companies and is available as a statutory adjustment in income tax calculations, it is our practice for ratemaking

³⁸ Companies’ Initial Brief at 17.

purposes that the tax effect of the statutory adjustment reflecting the difference between book and tax depreciation be added back to current income taxes to be included in rates paid by customers. In this way the Companies immediately receive the benefits of the accelerated depreciation in the form of cash payments in rates paid by customers regardless of a tax loss carryforward created by the consolidated AEP tax filing.

The decision to file for a PLR is up to the Companies. If they make such a filing they must officially inform this Commission in advance, provide us with the request before it is filed with the IRS, and seek Commission input into their request for the IRS ruling. If the Commission does not believe that the request is factual, adequate and complete the Commission shall provide input to be made part of the request to make it factual, adequate and complete from the Commission's perspective. In the request, the Companies and the Commission may then inform the IRS that (1) the West Virginia Commission has reviewed the request and believes that the request with input from the Commission is adequate and complete; and (2) that the Companies will permit the Commission to participate in any Associate office conference with the IRS concerning the request.

To protect the Companies and their customers, as part of this decision the Commission authorizes the Companies to establish a regulatory asset equal to the return that would be associated with inclusion of an amount equal to the Companies' requested stand-alone NOLC Deferred Tax Asset in the calculation of rate base, as well as the net excess amortization of excess Accumulated Deferred Income Taxes in the calculation of the cost of service in this case. The regulatory asset shall be booked commencing on August 29, 2025, which is the date that rates in this case are authorized to go into effect. The Companies will be eligible to request recovery of that regulatory asset if they receive an IRS determination that the exclusion by this Commission of the standalone NOLC Deferred Tax Asset from the calculation of rate base constitutes a normalization violation. If the IRS determines that such exclusion does not constitute a normalization violation, the regulatory asset will be written-off and not recovered from customers.

4. Parent Company Loss Adjustment (PCLA)

Beginning in 2014 the Commission changed its long-standing policy of calculating an effective income tax rate by comparing the actual normalized taxes, including the reduced taxes created by loss companies (excluding accelerated depreciation in the losses) to the normalized taxes of companies in the consolidated income tax filings that had positive taxable income.

As a simplified example of our historical income tax calculations under the effective tax rate approach, if companies in the consolidated group with positive

taxable income had normalized taxable income of \$3,000,000 and the parent and other loss companies had normalized tax losses of \$1,000,000, the net taxable income would be \$2,000,000.

At a 21 percent tax rate, the income tax by the consolidated group would be \$420,000 ($\$2,000,000 \times .21$).

To assign customers their proportionate share of the normalized taxes applicable to the consolidated group the Commission calculated an effective income tax rate of 14 percent ($\$420,000 \div \$3,000,000$).

If a West Virginia jurisdictional utility was a taxable income company and had \$1,000,000 in normalized taxable income, or one-third of the positive normalized taxable income of the group, the Commission would calculate an income tax liability for ratemaking of \$140,000 ($\$1,000,000 \times .14$). This was equal to one-third of the normalized tax of the consolidated group as would be expected since the utilities' \$1 million taxable income was one-third of the \$3 million total and was considered fair by the Commission.

In the 2014 rate case the Companies argued that because the consolidated tax return was dynamic and changed from year to year, the use of the effective tax rate might assign too much of the tax benefit of the consolidated group losses or the parent company loss (PCL) to West Virginia customers. Although the Commission used an average of multiple years to calculate the effective tax rate, the Companies argued that because taxable income in a rate case may be higher than future actual taxable income, the use of an effective tax rate on proforma taxable income would assign too much of the future tax benefit of consolidated taxable income losses to West Virginia customers.

In the 2014 case the Companies suggested that the more limited PCL was used by some regulatory commissions to recognize the tax benefits of participating in a consolidated tax return instead of the use of all loss companies. In addition, they argued that the PCL should not be converted to an effective tax rate but there should instead be a specific allocation of the PCL to the West Virginia jurisdictional utility.

The Commission agreed to change its prior use of all loss companies and to depart from the use of an effective tax rate and instead use a PCL approach. Instead of calculating an effective tax rate, the Commission agreed to allocate the average PCL to the West Virginia utility based on the utility's share of the taxable income in the years used for the averaging. In explaining the reasoning for the increment of PCL and the allocation thereof in its order, which dedicated twenty-four pages to the subject, the Commission stated:

The Commission will continue to utilize PCLA in determining current FIT expense because the taxable losses of the parent company are, at least arguably, different from the taxable losses of other subsidiaries in a utility holding company structure. The holding company parent taxable losses differ from subsidiary losses in that those taxable losses are expected to continue indefinitely. . . .

Because the parent company loss continues indefinitely, and is largely driven by costs that are related to all subsidiaries, it is at least arguably reasonable to allocate a portion of the permanent tax savings of the parent company in the rate setting process....

The Commission will base the CTS on only the PCLA and reduce the standalone taxable income of the Companies by their pro rata share of the parent company loss. The PCLA will be determined by multiplying the parent company taxable losses by the Companies' West Virginia jurisdictional ratio of positive taxable income (after adjustments for the impact of accelerated depreciation and Unit of Property capitalized Repairs deductions that are normalized for rate recovery) to total adjusted positive income of the consolidated group [emphasis added]. This CTS methodology is consistent with the PCLA approach proposed by the Companies and consistent with the methodology prescribed by the Tax Sharing Agreement between the Companies and AEP.

The Companies filing reflects only their allocated share of the PCLA for the 2013 test-year; however, the Commission based the PCLA adjustment on the three-year average of the parent company losses included in the consolidated income tax information for the 2011-2013 historical period. The Companies average West Virginia jurisdictional adjusted pro rata share of the PCLA is \$5.348 million based on the Companies pro rata share of AEP total adjusted positive taxable income for the 2011-2013 historical period.³⁹ (Emphasis added.)

In this case the issue revolves around the amount of parent company tax loss allocated to West Virginia, a number that was a \$5.348 million deduction from taxable income in the 2014 case.

³⁹ Appalachian Power Co. and Wheeling Power Co., Case No. 14-1152-E-42T, Comm'n Order, May 26, 2025, at 66-67.

In its filing, Staff used an allocated share of the PCL to reduce taxable income by \$6,577,243.⁴⁰ It is not clear in the filing of the Companies, but the Staff stated that the Companies allocated only \$2,134,385 of the parent company tax loss in its tax calculation.⁴¹

Contrary to the criticism of the clarity of the Staff adjustment we find the basis for the Staff adjustment clearly detailed in the Staff direct testimony.⁴² The Staff showed its calculation based on a three year average as follows:

Parent Company Federal Income Tax Loss Apportioned					
Description	2020	2021	2022	3 Year Total 2020 - 2022	Average
Parent Company Loss	(160,501,586)	(187,698,216)	(289,878,266)	(638,078,069)	(212,693,023)
APCo - Federal Taxable Income	288,917,730	-	-	288,917,730	
WV Allocation	0.420872	0.420872	0.420872		
Allocated Taxable Income	121,597,383	-	-	121,597,383	
WPCo Federal Taxable Income	26,068,790	-	-	26,068,790	
Total	147,666,173	-	-	147,666,173	
Total AEP System Positive Taxable Income	1,382,556,559	1,315,048,801	2,077,581,344	4,775,186,705	
Total AEP System Positive Taxable Income - APCo					
Total AEP System Positive Taxable Income - WPCo					
Allocation Factor				3.09%	
Allocation of Parent Company Losses to WV Jurisdiction					(6,577,243)
APCo				2.55%	(5,416,105)
WPCo				0.55%	(1,161,138)

In the three years used by Staff to determine the West Virginia share of the parent company tax loss the combined West Virginia Companies had taxable income in only 2020. They had tax losses in 2021 and 2022. Using the West Virginia share of the positive taxable income of the Companies in the three year period, which was \$147,666,173, as compared to the total of all positive AEP taxable income companies, which was \$4,775,186,705, Staff calculated the West Virginia prorata share of the PCL as 3.09 percent. Staff used that percentage to allocate \$6,577,243 PCL to West Virginia.

⁴⁰ Staff GMC-D Attachment 1, Schedule 1, Page 2 at Bates 47.

⁴¹ Staff Exh. GMC-D at Bates 24.

⁴² Staff GMC-D Attachment 2, Schedule 1, Bates 55.

In rebuttal, Mr. Hodgeson, the Companies tax witness, presented a schedule explaining why he believed the Staff calculation was incorrect. His rebuttal schedule shows that he believes that the allocation should be zero because of the tax losses of the Companies in 2021 and 2022.⁴³

Description	2020	2021	2022		
Parent Company Loss	(160,501,586)	(187,698,216)	(289,879,266)	(638,079,069)	(212,693,023)
APCo - Federal Taxable Income	288,917,730	(52,446,280)	(218,954,781)	17,516,669	
WV Allocation	0.420872	0.420872	0.420872		
Allocated Taxable Income	121,597,383	(22,073,171)	(92,151,937)	7,372,275	
WPCo Federal Taxable Income	26,068,790	(8,042,902)	(143,054,867)	(125,028,979)	
Total	147,666,173	(30,116,073)	(235,206,804)	(117,656,703)	
Total AEP System Positive Taxable Income	1,382,556,559	1,315,048,801	2,077,581,344	4,775,186,705	
Total AEP System Positive Taxable Income - APCo					
Total AEP System Positive Taxable Income - WPCo					
Allocation Factor				0.00%	
Allocation of Parent Company Losses to WV Jurisdiction					0
APCo				0.00%	0
WPCo				0.00%	0

Mr. Hodgeson testified that the losses of the Companies should be included in the determination of their prorata share of the PCL. Because his schedule includes both the WV losses and positive taxable income in the proration, the Companies have no taxable income, so he calculates a zero percent allocation factor and zero allocated PCL to West Virginia.⁴⁴

Commission Decision

The Commission agrees with the Staff calculation. As shown in the Staff direct exhibits, and in the Table in Mr. Hodgson's Rebuttal, the Staff determined the total positive taxable income of the Companies and compared that to the total positive income of the AEP consolidated group.⁴⁵ That Staff calculation using West Virginia utility positive taxable income compared to total positive taxable income of the consolidated group is what the Commission described in the 2014 Order.

⁴³ According to Staff, the Companies included \$2.1 million PCLA in their filing, but we cannot identify that number based on our review of the Companies' filing.

⁴⁴ Cos. Exh. DAH-R at Bates 155.

⁴⁵ Staff Exh. GMC-D Attachment 2, Schedule 1 at Bates 55.

"The PCLA will be determined by multiplying the parent company taxable losses by the Companies' West Virginia jurisdictional ratio of positive taxable income ... to total adjusted positive income of the consolidated group... The Companies filing reflects only their allocated share of the PCLA for the 2013 test-year; however, the Commission based the PCLA adjustment on the three-year average of the parent company losses included in the consolidated income tax information for the 2011-2013 historical period."⁴⁶ [Emphasis Added].

The table above, clearly shows that the Staff used the total adjusted positive taxable income for the three year period, which was \$147,666,173 and compared that to the positive income of the consolidated group to arrive at the allocation factor of 3.09 percent. It then applied that to the three year average of the parent company losses for the same three year period.

The Companies witness rebuttal calculation, also shown above, does not comply with the allocation described by the Commission in the 2014 Order. Instead, he calculates a zero allocation based on inclusion of large tax losses of the West Virginia companies in the determination of the allocation factor. Mr. Hodgeson, in effect, compares the negative taxable income (including losses) of WPCo and APCo to the positive taxable income of the consolidated group. We do not accept that as a correct method of determining the West Virginia allocated share of the PCL.

We understand that alternative methods of determining a reasonable allocation of the PCL in the income tax calculation can be considered. Because of two anomalous years (we presume largely due to the ENEC disallowance) it might be argued that the three year average chosen is not representative of expected future results and another average calculated from more typical years should be used. Or, a shorter or longer period for averaging positive taxable income may be proposed. In this case, the only years in the record were 2020, 2021 and 2022, and two of those are obviously not representative of expected future results. A party could have argued therefore that only 2020 was a representative year and it alone should be used for the allocation. As the Companies' witness pointed out, the PCL was much less in 2020 than the three year average.

The Companies only had positive taxable income in 2020 when the parent company loss was \$160 million, yet Staff's calculation allocates the average parent company loss of \$212 million, \$52 million greater

⁴⁶ Case No. 14-1152-E-42T, Comm'n Order, May 26, 2014, at 67.

than the year in which the Companies would have been allocated any loss.⁴⁷

We agree. We should consider using only the \$160 million PCL to determine an allocation of the PCL to the Companies. The West Virginia allocation factor for that year alone is 10.7 percent (\$147,666,173 divided by \$1,382,556,559). That would result in a West Virginia allocated share of the \$160 million PCL of \$17.1 million instead of the Staff calculation of \$6.6 million. We can only wonder why the Companies did not suggest a three year average that excluded the anomalous years. The one typical year allocation, however, was not advocated by Staff and the Companies did not offer additional years to develop an average that was typical of what could have been expected in the future. Such potentially reasonable alternatives were not presented by any party and we will not depart from the three-year average of positive normalized taxable income of the West Virginia jurisdiction and the total consolidated group for the allocation factor applied to the three year average PCL as calculated by Staff.

5. Corporate Alternative Minimum Tax (CAMT)

The Commission will not impute a Corporate Alternate Minimum Tax (CAMT). The minimum would not apply to the Companies on a standalone basis, and whether a CAMT would apply to the consolidated AEP group in the future is purely speculative. Moreover, how to reasonably allocate a CAMT of the AEP consolidated group to West Virginia would require more than the speculative information available in this case.

The Companies suggested an alternative of deferring any difference between the actual CAMT incurred by the Companies and the amounts reflected in base rates. We find that to be reasonable, considering that we have required the effects of extensive tax law changes to be deferred and reviewed by the Commission for rate treatment outside of base rate cases. The amount deferred, if any, will be subject to review and the Companies will have the burden to show that the deferred amounts are correctly assigned to West Virginia or reasonable allocable to West Virginia. The Commission will consider the deferred amount for reasonableness, applicability and appropriate rate treatment when the Companies propose an amortization in a future proceeding.

⁴⁷ Cos. Exh. DAH-R at Bates 155-56.

D. OPERATING INCOME AND OPERATION AND MAINTENANCE (O&M) EXPENSES

1. Generation O&M Adjustment

The Companies incurred \$164 million in generation O&M expenses in the test year 2023 and are forecasting higher expenses in the coming years. The Companies proposed an adjustment of \$8,295,326. The Commission will include that adjustment for the same reasons discussed in the section above titled Construction Work In Progress (CWIP) Inclusion in Rate Base regarding capital expenditures on the power plants. West Virginia has historically been blessed for its energy resources. Those, along with river transportation for fuel have made West Virginia a net exporter of electricity providing reliable and economical electricity supply to customers in surrounding states as well as to West Virginia customers. Recent over-reliance on intermittent resources that were encouraged by policies of the federal government and other states is leading to a recognized shortage of reliable base load dispatchable generation. Only coal and nuclear plants can realistically provide such generation capacity with a reliable level of onsite fuel to cover many weeks or months of generation.⁴⁸ The Companies are required by law to double down on maintenance of their coal-fired power plants to enable them to run reliably at a high capacity factor in the near term as well as to analyze how to extend their useful lives. Increasing expenditures on generation base rate maintenance O&M which is not included in ENEC costs is an important step.

Commission Decision

We will include the adjustment in revenue requirements. We will require the Companies to provide a report on actual test year generation O&M, by account and plant, going-level generation O&M allowed herein, by account and plant, and actual incurred generation O&M, by account and plant, in each future ENEC filing, or any other case if requested by the Commission.

2. Distribution O&M Adjustment

The Companies requested an adjustment of \$5.2 million to increase the test year \$60 million of expenditures for distribution O&M. More attention to pole attachments, pole inspections, and replacements are important functions that must be increased to improve reliability and also the ability to accommodate broadband expansion in West Virginia, which is badly needed, and which requires attachment

⁴⁸ Natural gas is also a valuable West Virginia energy resource which has the attributes of coal and nuclear for dispatchable base load electricity generation without on-site fuel, but with the advantage of close proximity to large natural gas storage and production fields.

on the Companies' poles that is unimpeded by old dilapidated poles. In recent pole attachment cases, we have heard testimony regarding the thousands of poles owned by the Companies and the relatively low number of poles that the Companies actually inspect each year.

Commission Decision

To improve those activities, we approve the \$5.2 million adjustment. We expect the Companies to spend that money productively on the distribution network. We further expect that the Companies will increase pole inspections and replacements, when necessary. This can improve reliability and also the ability to accommodate broadband expansion in West Virginia, which is badly needed, and which requires attachment on the Companies' poles that is unimpeded by old dilapidated poles.

To encourage improved maintenance of poles and expedited replacement, we will approve the Companies' \$5.2 million adjustment. We expect the Companies to spend that money productively on the distribution network. We further expect that the Companies will increase pole inspections and replacements, when necessary. To that end we will include an additional \$2.0 million in the Distribution O&M adjustment for pole inspections and maintenance and an additional \$20.0 million rate base adjustment to be dedicated to pole replacements. The Companies must budget the additional \$2.0 million for pole-related expenses and a substantial portion should be dedicated to hiring additional inspection crews that can also serve to participate in service restoration when needed after wide-area outages. We will also approve an additional \$20.0 million for capital investment related to poles. We expect reports showing additional pole maintenance and replacement activities in the future. The Companies must file a report within sixty days of the date of this order showing pole maintenance, replacements, and numbers of inspections by year over the last three years. Thereafter they must file a report every May and November showing the same information for six months ending March and September prior to the report date.

3. Long-Term Incentive (LW) Compensation

The CAD recommends elimination of stock incentives from revenue requirements.⁴⁹ Staff recommends elimination of all incentive pay plans.⁵⁰ The Commission will allow a sharing of the long term pay by including 50 percent of those costs in this case. We will, however exclude the stock incentives as

⁴⁹ CAD Exh. RCS-D at 66-67 (Bates 98-99).

⁵⁰ Staff Exh. GMC-D Attachment 1, Schedule 2.

recommended by CAD and exclude \$253,000 from the revenue requirements approved in this case.

4. Severance Costs

The Companies indicated they incurred severance costs during the test year associated with a voluntary severance program.⁵¹ Staff did not include any severance costs because severance is non-recurring in nature. CAD also proposed a going level adjustment for these costs. The Commission agrees that these are one-time expenses and should not be included in the revenue requirements in this case.

E. RATEMAKING MECHANISMS

1. Electric Rate Stabilization Surcharge (ERS)

The Companies proposed this surcharge as an alternative to traditional ratemaking.⁵² Under the ERS, the Companies would be allowed to automatically increase their total revenues by up to three percent annually without seeking regulatory approval. The Companies would then file a base rate case after four consecutive annual rate increases under the proposed ERS. The Companies argue that this proposal is similar to the statutorily authorized framework for solid waste carriers outlined in W. Va. Code § 24A-5-2a.

Electric rates are not comparable in magnitude and impact on customers to solid waste charges. We might consider some form of incentive ratemaking in the future, but this is not the time or case. We had some success over twenty years ago with stay-out agreements and frozen rates including ENEC rates. Something similar may be possible if the Companies' can reduce rates through securitization to get to a lower base, and if instead of a freeze the total rates including ENEC were limited to increasing at the lower of two percent or the rate of inflation. However, that is a thought for another day.

Commission Decision

The Commission will deny the Companies' proposal because it departs too much from cost-based ratemaking at too high a price. Although the Companies may argue that it is similar to a surcharge and would be reviewed every four years in a full base rate case, the Commission does not agree. The Commission has

⁵¹ Cos. Exh. AWA-R at p. 21 (Bates 79).

⁵² CSE Exh. JRB-D at 104 (Bates 110).

approved surcharges for limited, specific costs that are provable and then trued-up at the end of one or two years. To allow an automatic rate increase each year for four years far exceeds the purpose of a surcharge.

2. Environmental and New Generation Surcharge (ENG)

The Companies recommended the ENG to replace the Environmental Compliance Surcharge and the Renewable Energy Tariff.⁵³ The Commission declines to adopt the ENS.

3. Vegetation Management Program (VMP)

In Case No. 13-0557-E-P, the Commission approved a formal VMP for the Companies with a surcharge to be collected beginning at the conclusion of Case No. 14-1152-E-42T.⁵⁴ The Commission has monitored the VMP over the past decade and, while the Companies should continue to endeavor to improve vegetation management, program costs seem to be stabilizing. Therefore, the Commission will eliminate the vegetation management surcharge and add the current approved amount of the program back into base rates.

In order to true up the surcharge amount collected since the last VMP true up, the Companies should file, with their next ENEC case, an accounting of the VMP surcharge in the most recent filing. The Commission will account for this final true up at that time. The Companies should continue to maintain vegetation management at the same level as today and on a four-year cycle. Additionally, the Companies should spend the entire amount of funds each year that are currently allotted in the VMP surcharge or more. The Companies should file, every six months, a report accounting for the amount of money they spent during that period on vegetation management. The report should be filed using the same schedule discussed above for pole maintenance, replacement and inspections. If vegetation management expenditures decrease, the Commission will consider a show cause proceeding designed to establish a more formal and mandatory vegetation management expenditure program in conjunction with targets for reliability indices that contain incentives and penalties. We do not wish to go down that path and do not believe that will be necessary given the Companies' historical commitment for improved reliability and emphasis on vegetation management.

⁵³ Companies Initial Brief at 26, July 17, 2025.

⁵⁴ Appalachian Power Co. and Wheeling Power Co., Comm'n Order at 89, (May 26, 2015).

F. RATE DESIGN

1. Jurisdictional Cost-of -Service (JCOS)

a. Allocation Factor Study

In its Initial Brief, the Staff pointed out that Staff Witness Eads testified that there were errors in the allocation factors developed by the Companies in the demand/energy study. He identified the use of an incorrect factor to apportion APCo's peak demands between West Virginia and Virginia in the month of September 2023 which overstated the factor used to develop the production allocator for West Virginia.⁵⁵ Staff stated that the Companies agreed with Staff regarding the error. The Commission will use the Staff recommended allocations.

b. Jurisdictional Allocation – Kingsport

Staff witness Eads argued that the Kingsport demand values were not adjusted for losses like all other customers.⁵⁶ The Companies indicated that the Kingsport values were reported in the Study at the generator level and, therefore, already included transmission losses.⁵⁷

Staff determined that this was not accurate because the peak demands for Kingsport reflected in the Study were the same as APCo's metered demands. Staff adjusted the Kingsport values in the Study by a loss factor of 3.31 percent.

The Companies also failed to apply an energy loss adjustment.⁵⁸ Staff confirmed that all other wholesale customers had their metered loads adjusted for losses in the Study. Staff adjusted the Kingsport energy values in the Study by a loss factor of 2.96 percent.⁵⁹

The Companies did not agree with either adjustment. In rebuttal testimony, Companies witness Johnston indicated that Kingsport is classified as an AEP operating company and, therefore, is not considered a wholesale load by AEP

⁵⁵ Initial Brief of Staff at p. 9 (Bates 16), July 17, 2025.

⁵⁶ Initial Brief of Staff at p. 10 (Bates 17).

⁵⁷ Staff Exh. TRE-D at 8 (Bates 103).

⁵⁸ Staff Exh. TRE-D at 8 (Bates 103).

⁵⁹ Id.

Transmission. The Companies said that, in order to change Kingsport's classification, they would have to perform a study to determine the appropriate treatment of delivery points and load.⁶⁰

Commission Decision

The Commission agrees with Staff. Whether Kingsport is a wholesale customer, a retail customer, or an affiliate has nothing to do with adjusting measured demand and energy at the customer level back to generation levels. The loss factors are different for loads delivered at transmission, sub transmission and various distribution levels. It is our practice to adjust non-jurisdictional loads to generation levels for allocation purposes. That exercise also requires adjusting retail load to generation levels. Retail loss adjustment factors are also common in class cost of service studies.

For example, if a group of customers at the distribution level has metered energy usage of 1,000,000 MWH and a large industrial customer on the transmission system has metered usage of 1,000,000 MWH, using those meter level numbers would result in a 50 percent allocation of upstream costs, both transmission and generation, to each customer. However, if the losses on the transmission system are 2 percent and the losses at the distribution system level are 8 percent, the lost energy to deliver service to the industrial customer would be 20,408 MWH and the energy required at generation level to serve the customer would be 1,020,408 MWH. For the distribution customers with the combined transmission and distribution loss factor of 10 percent the amount of generation needed to provide 1,000,000 MWH would be 1,111,111 MWH. The combined energy to serve both customers is 1,131,519 MWH because of the line losses. To allocate the production and transmission costs upstream of the customer meter to load, the correct allocation factor would be 48 percent for the large transmission level customer and 52 percent for the distribution level customers. Failure to adjust both loads to the common generation level base would result in over allocation of costs to the industrial customer served at transmission level. Conversely if the line losses of the distribution customers were included in the allocation factor but the load factor for the transmission level customer was based on usage at the customer meter, there would be an under allocation of costs to that customer.

Kingsport is no different for cost allocation purposes. Failure to use a line loss factor would be the equivalent of using 1,000,000 MWH for the distribution level customers in the above example.

⁶⁰ Cos. Exh. KMJ-R at 3-4 (Bates 168-69).

c. Generation and Transmission Property Tax Allocation

Staff allocates property taxes on generation plant between jurisdictions based on demand or energy factors that are also used to allocate the cost of boilers, turbines, cooling towers and all other costs associated with a generating plant.⁶¹ The Companies presented an argument that property tax should be assigned to the jurisdiction that assesses the tax. The Companies' argument is that "Staff's approach ignores the practical reality that property taxes are assessed by the state tax authorities on generation and transmission assets based on their 'net plant.'"⁶² We fail to see any logic in that argument at all. While the Companies' position could by accident produce a realistic result for transmission where there is significant investment in both West Virginia and Virginia, it is clearly not reasonable for generation plant property taxes.

First, the Companies appear to be unaware that while the Board of Public Works requires a property tax filing that starts with net plant investment, the Tax Division in determining value applies a capitalized earnings factor to determine the final taxable property value. That factor can range both up and down depending on the weight given to capitalized earnings. The Companies should consider the valuation approach which is included in Chapter 11 of the West Virginia Code and in Rule 4 of the Valuation of Public Utility Property for Ad Valorem Property Tax Property Tax Purposes, 110 C.S.R. 1M before incorrectly describing how property taxes for public utilities are determined in West Virginia.

Valuation of Operating Public Utility Property (excluding interstate commercial motor vehicle property).

4.1. Unit method. -- The Tax Commissioner provides tentative assessments based on fair market value of operating property of public service corporations to be used as a guide by the Board of Public Works in establishing final assessed values for property tax purposes. In this regard the Tax Commissioner shall use the "Unit Rule" where applicable in furnishing tentative valuation estimates for the Board's consideration.

4.2. Generally accepted appraisal methods. -- In determining tentative assessments the Tax Commissioner shall consider, and use where applicable, three (3) generally accepted approaches to value: **(A) cost, (B) income, and (C) market data.** Application of these

⁶¹ Staff Exh. GMC-D at 18-20 (Bates 22-24).

⁶² Companies' Initial Brief at 31, July 17, 2025.

approaches shall recognize the impact of regulation on the value of utility operating property where applicable.

4.2.1. Cost approach. B Recognizing that public service corporations are predominantly cost regulated, when the cost approach is used in the valuation process, original cost less applicable depreciation shall be employed. In applying the cost approach, the Tax Commissioner shall consider three (3) types of depreciation (a) physical deterioration, (b) functional obsolescence, and (c) economic obsolescence.

4.2.2. Income approach. -- In developing income approach valuations, the Tax Commissioner shall estimate capitalization rates considering the interrelationships of the income to be capitalized and the capitalization rate. In this regard, net operating income after taxes, but before interest on long-term debt shall be given primary consideration as the point on the income stream to be capitalized. The bands of investment technique shall be employed in estimating appropriate capitalization rates.

4.2.3. Market data approach. -- Recognizing that a sufficient number of sales of public service corporations do not occur to enable application of the market data technique, the Tax Commissioner shall consider the substitute stock and debt technique. The stock and debt technique shall be used in instances where a utility class possesses actively traded stocks and bonds that enable reasonable valuation estimates to be made.

4.2.4. Correlations. -- Once generated, the various estimates of value shall be correlated into a final value estimate. The income approach value shall generally be given primary consideration in the correlation process.⁶³

Even if the assessment on generation was solely on net plant value, we do not agree with the Companies that the assessment on a generation plant should be assigned to the customers in the state where that plant is located. The tax on the property is a cost of the plant just as much as the investment in equipment, the employee payroll, and the other plant O&M. Under the Companies' theory it could be argued that property taxes on the Ohio plant should be charged to someone other than West Virginia and Virginia retail customers. Maybe to wholesale customers only.

⁶³ 110 W.Va. C.S.R. 1M.

The same allocation of property tax should apply for transmission lines that serve customers throughout the service territory of the Companies and utilities in neighboring states. We will adopt the Staff approach which allocates transmission costs, production costs, and rate base to all customers.

The Commission will adopt the Staff recommendation regarding jurisdictional cost allocations.

d. Open Access Transmission Tariff (OATT) Revenue Allocation

Staff proposed an adjustment related to PJM OATT.⁶⁴ At the hearing, Staff witness Eads testified that he was withdrawing his OATT adjustment.⁶⁵ The Staff and Companies agreed that no adjustment was necessary to the Staff Revenue Requirement calculation because the revenue adjustment was offset by a contra-adjustment in the base rate case and had not affected the revenue requirement in this case.⁶⁶

No further adjustment by the Commission is necessary.

2. Class Cost of Service (CCOS)

a. Production Plant Allocation

For the CCOS, the Companies allocated production plant based on demand using the 12CP methodology.⁶⁷ CAD witness Dismukes recommended that the Companies use the average and peak method wherein both demand and energy components are considered.⁶⁸ The Companies argued that adoption of Dr. Dismukes' methodology would result in significant cost shifts between customer classes.⁶⁹ Staff and other parties recommended using the 12 CP methodology.⁷⁰ The Commission agrees with the Companies, Staff, and intervenors that supported a cost allocation based on a 12 CP theory rather than the Average and Peak method favored by CAD.

⁶⁴ Staff Exh. TRE-D at Bates 108-09.

⁶⁵ Tr. II at 299-301.

⁶⁶ Staff Initial Brief at 13 (Bates 20).

⁶⁷ Cos. Initial Br. at 35.

⁶⁸ CAD Exh. DED-D at Bates 434-41.

⁶⁹ Cos. Initial Br. at 35.

⁷⁰ WWEUG also recommended a 12 CP but with an adjustment as discussed in the next section.

b. Economic Development Rider (EDR) Discounts to Rate Schedule LCP and IP

Because the EDR offers significant discounts for eligible customers who qualify under the Companies' Rate Schedules LCP, IP, or GS, the Companies allocated EDR discounts to Rate Schedules LCP and IP.⁷¹ WVEUG argued that the EDR discounts should be allocated to all classes alleging that all customers benefit from additional load by way of EDR discounts.⁷² CAD agreed with the WVEUG position but said the allocation should be on a 12 CP Average and Peak methodology not the 12CP methodology.⁷³ During the evidentiary hearing, WVEUG agreed with CAD's position.⁷⁴

Commission Decision

The Commission will defer ruling on this issue at this time. It does not affect the overall revenue requirement.

c. Special Contract Customers A, B, and G Revenue Adjustments

The Companies seek to reclassify the special contracts related to Customers A, B, and G to Rate Schedule LCP and IP classifications.⁷⁵ The Companies argued that these special contracts "align with the rate structures and load characteristics of the LCP and IP classes, and absent a [s]pecial contract, these customers would be included in these classes because of the size and shape of their loads."⁷⁶ The Companies also argued that assigning these special contracts to the class to which they are most closely associated ensures greater consistency in the CCOS.⁷⁷ Staff disagreed with the Companies' reclassification on the basis that these special contracts often contain an interruptible or curtailment obligation provision.⁷⁸

⁷¹ Cos. Initial Br. at 36.

⁷² WVEUG Exh. SJB-D at Bates 26.

⁷³ CAD Exh. DED-R at 9-12 (Bates 133-36).

⁷⁴ Tr. Vol. II at 23.

⁷⁵ Cos. Exh. MSS-R at Bates 274.

⁷⁶ Id.

⁷⁷ Id.

⁷⁸ Staff Exh. TRE-D at Bates 154.

Commission Decision

The purpose of Special Contracts is to allow special rates and terms based on the individual customers characteristics. We will keep the special contracts as separate rate classes unto themselves.

d. Non-coincident Peak (NCP) vs. Sigma Non-coincident Peak (SNCP) Allocation of Secondary Distribution Costs

The Companies' allocated CCOS on the same basis used in Case No. 18-0646-E-42T. Staff advocates allocation of secondary distribution costs on a different basis, using a different denominator in the allocation formula.⁷⁹ The difference in the two methods is, in most cases, less than one percent per class.⁸⁰

Commission Decision

The Commission will defer ruling on this issue at this time. It does not affect the overall revenue requirement.

e. Revenue Distribution or Allocation and Rate Design End of Test Year Customer Revenues Adjustment (Statement G, Adjustment 10-OR)

Staff disagreed with the Companies' adjustment to reflect known and measurable changes to the end of test year number of customers, their usage levels, and for the migration of customers between classes.⁸¹

Commission Decision

This adjustment falls into the area of matching average test year rate base with average test year expense and revenue units. The potential for a mismatch is high when adjusting units of expense and revenue. The Commission will not allow 100 percent of the proposed adjustments because there has not been a sufficient showing by the Companies of potential cost reductions associated with changes in revenue units. We will allow 50 percent of the proposed adjustment.

⁷⁹ Staff Exh. GMC-D at Bates 29-30.

⁸⁰ Cos. Exh. MSS-R at Bates 276.

⁸¹ Cos. Exh. MMS-D at Bates 4621; Staff Exh. GMC-D at Bates 18-19.

f. Special Contract Base Rate Revenues (Staff Adjustment 8)

Staff increased certain special contract base rate revenues. The Companies contend that the Staff witness used incorrect rates for the calculations underlying its adjustment, and, therefore, Staff's adjustment should be rejected.⁸²

Commission Decision

We will not modify the test year special contract revenue.

Book-to-Bill Revenues Adjustment (Statement G, Adjustment 1-OR)

The Companies reconciled the revenue difference between billed and accrued revenue recorded on the Companies' books with the revenue generated by applying test-year billing determinants to test-year rates.⁸³ Staff rejected the adjustment.⁸⁴

Commission Decision

The Companies' adjustment is a shortcut to adjustment factors normally used. The Commission will adopt the Staff calculations.

g. Rate Design Issues under Rate Schedules SWS (Sanctuary Worship Service) and GS (General Service)

Staff proposed to weather normalize rates under Rate Schedules SWS and GS based on a twelve-month sampling of data whereas the Companies used ten years of data.⁸⁵ The Companies argued that the data they used is more robust, more accurate, does not use statistically insignificant factors, and is far better at eliminating one-off trends or data points.⁸⁶ Despite their position, the Companies stated that they "are amenable to conducting [their] own tariff-level regressions in future cases to identify weather sensitivity."⁸⁷

⁸² Cos. Exh. MMS-R at Bates 283; Staff Exh. GMC-D at Bates 19-20.

⁸³ Cos. Exh. MMS-D at Bates 4619-20.

⁸⁴ Staff Exh. GMC-D at Bates 17-18.

⁸⁵ Cos. Exhs. RLE-D at Bates 194-98, MMS-R at Bates 288.

⁸⁶ Cos. Exh. MMS-R at Bates 288.

⁸⁷ Cos. Exh. MMS-D at Bates 289.

Commission Decision

We agree with the Companies. The longer term normalization approach is better at smoothing the normalization. We will adopt the Companies' calculations.

h. Rate Design – Elimination or Change to 10kW Maximum Demand Limitation in Rate Schedule SGS

CSE witness Barnes recommended that the referenced threshold of 10 kWh be eliminated or raised to 50 kWh so that customers switched to Rate Schedule GS from Rate Schedule SGS will avoid experiencing a significant bill increase due to the Rate Schedule GS demand charge.⁸⁸ The Companies argued that the 10kW is long-standing and should stay because they have calculated base rates and rider rates in various proceedings using these rates. Additionally, the Companies argued that Mr. Barnes does not provide any data that customers are actually worse off under the current threshold.

Commission Decision

The Commission agrees with the Companies that the 10kW threshold should remain in place.

i. Removal of Rate Schedule GS Maximum Charge Provision

The Companies proposed to eliminate the Rate Schedule GS maximum charge limitation to "ensure they receive adequate compensation for certain fixed costs otherwise included in a minimum bill computation."⁸⁹ Companies argue that the maximum charge limitation can result in Rate Schedule GS customers not adequately contributing to their share of fixed costs.⁹⁰ The Companies argued that the removal of this charge would insure that Schedule GS customers that use less than 100 kW and trigger the minimum charge are not paying for their demand-related cost responsibility and shift that burden to other customers within Rate Schedule GS.

Commission Decision

The Commission will not approve a demand change in commercial rate schedules that could result in unexpected increases. In the past we have

⁸⁸ CSE Exh. JRB-D at Bates 123-132.

⁸⁹ Cos. Initial Br. at 42; Cos. Exh. MMS-D at Bates 14-15.

⁹⁰ Cos. Exh. MMS-R at Bates 285-86.

considered freezing rate schedules or rate schedule thresholds for existing customers. We are not prepared to take such a step at this time but would consider such a proposal or a phase-in proposal if presented by the in a separate income neutral tariff filing.

j. Rate Schedule RS Time-of-Day (TOD) Recommendations

CSE witness Mr. Barnes recommended during this case that:

(i) The on-peak hours for Schedule RS-TOD should be shortened to four hours or less in order to provide customers with more actionable opportunities for beneficial load-shifting; (ii) Schedule RS-TOD's basic service charge should be set at the Schedule RS basic service charge rate to better align with cost-causation principles, and (iii) concurrent participation in Schedule RS-TOD and the residential low-income discount (the SRR-RS Amendment) should be permitted.⁹¹

The Companies are amenable to shortening the TOD on-peak window to four hours, but argue that Mr. Barnes' recommendation does not include sufficient analysis to determine which four or fewer hours would be appropriate. The Companies recommended that they conduct an analysis of the RS-TOD class to adjust the on-peak window to encourage customer load shifting and realized savings.⁹² The Companies are amenable to setting the RS-TOD service charge at the Schedule RS basic service charge rate and allowing RS-TOD customers to participate in SRR-RS as long as the customers satisfy the requirements listed in W. Va. Code §24-2A-1 et seq.⁹³

Commission Decision

The Commission agrees with CSE and the Companies that Schedule RS-TOD's basic service charge should be set at the same rate as Schedule RS basic service charge rate to better align with cost-causation principles and eligible customers should be allowed concurrent participation in Schedules RS-TOD and SRR-RS assuming that those customers are eligible to participate in Schedule SRR-RS. The Companies should analyze the Schedule RS-TOD to adjust the on-peak window to four or fewer hours to encourage customer load shifting and realized savings.

⁹¹ CSE Exh. JRB-D at 131-32 (Bates 137-38).

⁹² Cos. Exh. MMS-R at 15 (Bates 293).

⁹³ *Id.* at 16 (Bates 294).

Changes such as those proposed can be considered outside of a base rate case. The Companies should further analyze this issue and file proposed tariff changes on or before July 1, 2026.

k. LED Lighting

The Companies initially used a ten-year life expectancy before agreeing to a fifteen-year life expectancy for LED lights. Mr. Barnes, testifying for CSE argued that the life expectancy of LED street lights is typically 100,000 hours. At 4,000 hours per year, life expectancy would be twenty-five years. But, Mr. Barnes suggested using a life expectancy of twenty years for rate design purposes. Companies witness Mr. Spaeth then suggested that the Companies could use a fifteen year life expectancy as a middle ground to reduce the Companies' proposed LED street light conversion rate.⁹⁴

Additionally, the Companies included in their rate design a removal cost component. CSE argued that this cost should not be included. We agree with CSE that the Companies should not include a removal cost component in rate design and decline to approve this cost component.

Commission Decision

The Companies should recalculate the ownership cost rate component for LED lighting options under Schedule OL and Schedule SL using an assumed lifetime of fifteen years and without a removal cost component.

l. Rate Design – Roll-in of MRBC Rates

The Companies did not object to Staff's proposal pertaining to an increase in customer charges for non-residential customers by the MRBC rate being rolled into base rates and then increased by Staff's percentage increases over current rates.⁹⁵

Commission Decision

The Commission will approve the staff proposal. The Companies will reflect the staff rate design in developing rates consistent with this Order.

⁹⁴ Tr. I at 212-216; Cos. Exh. MMS-R at 16-17 (Bates 294-295).

⁹⁵ Cos. Exh. MMS-D at Bates 286; Staff Exh. GMC-D at Bates 31.

m. Residential Winter Tail Block

Staff witness Eads proposed modifications to the Companies' winter energy block and to block 1 and block 2 rate differential. The Companies agreed with these modifications theorizing that they could potentially alleviate high bills for residential customers. The Companies agreed to reduce the winter tail block threshold to 1,100 kWh from the current 1,350 kWh and to extend the winter tail block to include March.⁹⁶

Commission Decision

We approve that change which the Companies should include in the tariff designed in accordance with this Order.

3. Energy Bill Assistance Issues

a. Dollar Energy Fund

From 2020 through 2024, the Companies contributed \$250,000 in shareholder funds per year to the state Dollar Energy Fund (DEF). The Companies did not require a ratepayer contribution to the DEF during this time period and are not requesting, in this case, Commission consent or approval to use ratepayer money to contribute to the DEF. The Companies have also not committed to continue making a shareholder contribution to the DEF.

Commission Decision

To aid customers needing this assistance and because the Companies have not committed to a shareholder contribution beyond 2024, the Commission will include in base rates a \$1 million revenue requirement and require the Companies to contribute that amount to DEF. The full amount should be contributed prior to the beginning of the upcoming winter period. The Commission encourages the Companies to continue participation in the DEF. The historical amount is small and a larger contribution would be appreciated. The Companies may not benefit by their contribution except for the positive image it conveys in the community. We are sure however, that when the dollars are used to pay some customer bills, the Companies are offsetting some level of bad debts that would otherwise have to be written off.

⁹⁶ Cos. Exh. MMS-R at Bates 287.

The Commission also will require the Companies to increase their DEF grant limits from \$300 to \$500 per customer per year and allow applications year-round instead of only December through March. Each of Monongahela Power Company and The Potomac Edison Company have a \$500 grant limit and a year-round application period. The Commission finds this to be appropriate and helpful to West Virginia electric customers. The Companies should request that DEF make these changes. When the changes are made, the Companies should file a closed entry in this case informing the Commission that the changes were made. If the DEF declines to make the changes, the Companies should file a closed entry in this case informing the Commission why the DEF will not make these changes.

b. Low-Income Residential Discount Rider

The Companies currently have a tariff, the SRR-RS tariff, that provides a twenty percent discount for residential customers meeting certain income qualifications, for the billing months of December through April, corresponding to the usage months of November through March. CSE witness Barnes requested that this special billing rate include the months of July and August (billing months of August and September) as residential utility use is “typically relatively high” in those months.⁹⁷ The special rate for low-income customers was passed by the West Virginia Legislature and codified at W. Va. Code §24-2A-1 et seq. The statute permits the special discounted rates during the months of December through April only.

Commission Decision

West Virginia Law provides that a customer of a utility offering special reduced rates shall be eligible to receive such rates for each of the billing months of December, January, February, March and April.⁹⁸

The Commission, therefore, is unable to modify the effective date of the SRR-RS tariff that is subject to the statutory rate and funding mechanisms. We can, however, consider alternative funding through a revenue requirement that can be shared by all customers. The Companies shall prepare an analysis of the expected revenue requirement of a twenty percent discount in the months of July and August. That estimate should be filed by November 1, 2024. We are not requiring the discount, but we are requiring the cost impact filing for informational purposes.

⁹⁷ CSE JRB-D at 98-99 (Bates 104-05).

⁹⁸ W. Va. Code §24-2A-1.

4. Tariff Terms and Conditions

a. Revisions to Tariff Sheet 3-10

The Companies proposed to add language to Tariff Sheet 3-10 that establishes new requirements for temporary service. The Companies argued, in particular, that the definition of "permanent dwelling" be changed to bring it in line with the AEP Guide for Electric Service Installations. Staff argued that the language proposed by the Companies defeats the purpose of temporary or construction power and is unreasonable.⁹⁹

The Commission denies this request.

Changing "legally observed holidays" to "legal holidays"

The Companies noted that several tariff sheets would need this change to reflect the capability of the Companies' billing system to recognize only legal holidays. Staff witness Wright disagreed with the change because it would eliminate an off peak billing day when a holiday falls on a weekend.

Commission Decision

The Commission agrees with Staff and will not approve this change.

b. Removing Tariff Sheets 29-1 and 29-2 (Mitchell Base Rate Surcharge or MBRS)

Companies witness Short recommended removal of these tariff sheets effective upon implementation of new base rates. The other parties agreed that the MBRS should be eliminated. The MBRS became effective January 1, 2020, and was created to reflect 100 percent of the costs associated with WPCo's ownership interest in the Mitchell plant.¹⁰⁰ The MBRS was not intended to be permanent and was to be terminated in the next base rate case for the Companies. The MBRS should be terminated and this surcharge should be rolled into base rates. The Commission agrees with this recommendation as the Commission only intended the MBRS to run until the next base rate case.

⁹⁹ Staff Initial Brief at 58-59 (Bates 65-66).

¹⁰⁰ Appalachian Power Co. and Wheeling Power Co., Case No. 19-0564-E-T, Comm'n Order, Dec. 18, 2019.

c. Removing Tariff Sheet 44 (Tax Reform Rider or TRR)

Companies witness Short recommended removal of this tariff sheet because the TRR is no longer available. The tariff sheet should be removed.

d. Reconnection Charge

CSE witness Mr. Barnes recommended that the Commission eliminate reconnection fees for customers because advanced metering infrastructure is nearly complete and enables the Companies to perform disconnections and reconnections remotely.¹⁰² CSE argued that the historic cost basis for a reconnection fee, including a site visit by field personnel, is no longer applicable. The Commission agrees with this assessment, but without an analysis of the current cost basis for reconnection fees is hesitant to eliminate the reconnection charge completely. The Commission will, however, require the Companies to modify their tariffs to reduce reconnection fees by fifty percent. With the Companies' next base rate filing, they should file a cost analysis to justify a reconnection fee or request that the fee be eliminated.

5. Net Metering

The Companies proposed a new net metering tariff – NMS II – which the Companies asserted was modeled after the recently approved NEM Rider for Monongahela Power Company and The Potomac Edison Company, with adjustments to reflect the Companies' actual cost structure.¹⁰³

CSE and Solar Holler requested that the Commission reject the Companies' proposed NMSII.

Commission Decision

The Commission will approve a new net metering tariff for the Companies, using Staff witness Eads' methodology. The Companies should use Mr. Eads' methodology to calculate the new tariff.

a. Transition Time for NMS II

Various parties proposed differing timelines to transition from the previous net metering tariff to the NMS II. The Commission will adopt a deadline of March 1, 2026 for customers to file initial net metering applications to fall under the current NMS Rider conditioned on completion of installation of working facilities. This

¹⁰² CSE JRB-D Att. 5 at 12-14 (Cos. Response to CSE discovery requests 4-13(b)(i) and 4-14).

¹⁰³ Cos. Exh. RAS-R at Bates 196-98.

deadline should give customers sufficient notice of the change in deadline from the Companies' proposed December 31, 2024 deadline. Additionally, residential customers will have until September 1, 2026, and commercial customers will have, until March 1, 2027 to receive certificates of completion and continue to be eligible for the current NMS Rider.

G. COGEN/SPP Tariff

With regard to COGEN/SPP Tariff issues, the Staff agreed with the Companies' modified availability and payment provisions. Staff, however, objected to proposed language allowing the Companies to reduce energy payments to the customer at the day-ahead PJM LMP if a customer's operation leads to significant real time deviations. The Companies provided no testimony regarding this change and no information or explanation as to why the change is warranted. Additionally, the Companies disagreed with Staff's proposal to include a capacity payment in the Cogen/SPP Tariff. The Companies have capacity credits in their COGEN/SPP tariffs in Indiana, Michigan, and Kentucky.

Commission Decision

The Commission will not approve a rate design change at this time. We agree with staff that some accounting to justify the use of the day ahead prices if customers are affecting real time costs and revenue. The Companies can propose the change in a separate tariff filing. Even if the Commission does agree to approve a change between rate cases, we can review the issue on its own merits without all of the clutter involved in a massive base rate case.

Conclusion

In this Order, the Commission discussed all issues for which we have made decisions. The Companies will incorporate those decisions in a revised tariff. To the extent we did not specifically address a tariff change in this Order, that change is denied.

Although we approve a revenue requirement that will result in increased tariff rates, we will also be approving a securitization and will be issuing a securitization Order very soon. We agree with the proposal of the Companies and with the intent that securitization can result in the capitalization of a large portion of the investment approved in this base rate case and a large portion of deferred costs currently capitalized by the Companies current capital sources at lower capital costs, thereby reducing rates. Because of the necessary delay between this Order and a determination of the final rate reductions that will accompany securitization, we require a deferral mechanism for the base rate increase that would otherwise have

been required upon the issuance of this Order. Accordingly, we require that the revised tariff that the Companies file pursuant to our decisions herein maintain the present base rates, unchanged and add the new base rates increases as identifiable deferrable increments. The Companies will continue to bill customers at the current rates so there is no increase on customer bills resulting from this decision.

We authorize the Companies to calculate the monthly base rate increase that equates to the results of this Order and recover that amount from the ENEC surcharge billings. That will allow current recovery of the base rate revenue requirements without special deferral. However, it will impact the ENEC deferral. We will initiate an ENEC true up prior to the final securitization implementation in time to determine the ENEC under recovery deferral balance to roll into the securitization.

The Companies must develop rates that reflect the decisions made herein. We intend that all rate base, revenues and costs included in the various surcharge cases under review this year be rolled into base rates. Except for the Companies Business Ready Sites Program Surcharge (BRSP) investment¹⁰⁴ (which will be addressed in Case No. 24-0856-E-IDS) the roll in should include the levels of those surcharge-recoverable rate base and expenses through the most recent data included in the recent surcharge filings. We will initiate a true up proceeding when all costs that were formally recoverable in the surcharge cases are known and provide a mechanism that will recover those costs without an annual surcharge proceeding going forward. The Commission may consider incremental cost recoveries between rate cases on a limited and as-needed basis if that is proposed in the future, but we are not bound by past approvals to continue the surcharge approach. If there are such specific cost recoveries in the future, we will consolidate the implementation dates and simplify the filing requirements and reviews so that we do not return to a situation where there are numerous surcharge cases and numerous implementation dates.

III. FINDINGS OF FACT

Capital Structure

1. To the extent the AEP consolidated capital structure includes operating companies as well as the parent company, it is representative of the capital structure of an operating utility as opposed to simply a holding corporation.

¹⁰⁴ The BRSP is required by W. Va. Code §24-2-1n.

2. The proxy group of companies that the CAD relied on to derive a 56 percent debt and 44 percent equity capital structure are representative of utilities that provide distribution, transmission and in some cases production self-produced power supply.

3. The Commission has historically used a variety of techniques including point in time capital structures, adjusted point in time capital structures, and average capital structures, as well as its judgment and experience, to determine a reasonable capital structure.

4. Depending on economic or other circumstances, the Commission may review various historical, projected, and hypothetical capital structures.

5. Reliance on the actual capital structure of a utility at a point in time or over a restricted time frame does not reasonably consider the changes in capital structure over time or the danger of over or under-leveraged capital structure.¹⁰⁵

6. A lower equity capital structure will produce a lower overall rate of return and is beneficial for customers unless equity is so low as to restrict the ability of a utility to acquire debt at reasonable rates.

7. AEP is in control of the Companies' capital structure and can make equity infusions into the utilities at any time to increase the equity percentage in the capital structure.

Cost of Debt

8. With regard to the cost of debt there was very little difference between the Staff, CAD and the Companies on their average cost of debt. On a weighted basis the weighted cost of short-term and long-term debt proposed by the Companies and CAD was 4.98 percent. The weighted cost proposed by Staff was 4.95 percent.

9. Differences in regulatory procedures in Virginia and West Virginia such as our use of expedited recovery mechanisms for business ready sites, broadband expansion, investments to upgrade certain power plants, and deferrals of storm damage or other costs, could give rise to short term debt financing differences.

10. The different impacts on the need to carry short term debt, if there are any, could vary one way or the other on a state basis. The use of the total company

¹⁰⁵ Id.

capital does not require a detailed analysis of the reasons for debt levels on a state by state basis. We suggest that such a proposal would add a level of complexity not heretofore found in rate cases.

Return on Equity

11. The ROEs recommended by the expert witnesses in this case are: Companies - 10.5 percent; Staff - 9.25 percent; and CAD - 9.1 percent.

12. The Risk Premium model is not a primary model that has been adopted by this Commission and the FERC recently abandoned the Risk Premium model.¹⁰⁶

13. The DCF data presented in this case which cover different periods of time for the critical yield calculation, include a yield component of 4.1 percent from the Companies' witness - based on 2024 stock price data, 3.4 percent presented by the CAD witness - based on April, 2025 data, and 3.7 percent presented by Staff - based on stock prices over a thirteen week period ending in April, 2025. These yields represent actual dividends divided by actual stock prices. Yet, they are significantly different.

RATE BASE

Cash Working Capital

14. A cash working capital allowance recognizes that a company must pay cash for expenditures when bills come due although it may not collect revenue from customers to cover those expenditures until after the bills come due.

15. Our rules provide for inclusion of a working cash allowance, if justified by a cash working capital study.¹⁰⁷

16. A utility does not need to pay cash when depreciation comes due.

17. FERC does not prescribe rules for a cash working capital study for electric utilities although it does allow for the filing of a study or formula and provides guidance for such a study in its natural gas pipeline rules.¹⁰⁸

¹⁰⁶ Association of Businesses Advocating Tariff Equality v. Midcontinent Independent System Operator, Inc., 189 FERC ¶ 61,036 (Order on Remand, October 17, 2024).

¹⁰⁷ Rule 20.4.7, Rules for the Construction and Filing of Tariffs, 150 C.S.R. 2.

¹⁰⁸ 18 C.F.R. §154.312e(1).

18. The FERC Rule is similar to ours in that it describes cash expenses and taxes as components in a lead-lag study and does not list non-cash depreciation or earnings and dividends which are not expenses requiring cash working capital.

Period End Rate Base Adjustment

19. The Commission has allowed Companies to implement many special surcharges to reflect plant additions taking place not only in a rate case test year, but in non-rate case years. These adjustments tend to allow plant investments that are in addition to the average rate base in a base rate case to be periodically adjusted and to allow a return to the Companies on these investments after a base rate case.

20. Other investments have not been afforded or promised treatment in rate base in a base rate case because to do so would conflict with the matching principal that we believe is inherent in the use of an average test year rate base.

21. The matching principle for an average test year requires that investments in plant placed into service during a test year will reflect any offsetting revenue produced from those investments or expense reductions produced from those investments, adjusted only for known and measurable changes in expense rates and not units.

Construction Work In Progress (CWIP) Inclusion in Rate Base

22. The Companies' proposed rate base adjustment to include \$239 million in construction work on production, transmission and distribution completed and in service prior to January 1, 2025 is a request to depart from an average test year.

Coal Inventory Adjustment

23. The Companies proposed a \$10.1 million coal inventory adjustment that adjusts rate base upward by the difference between the average levels of inventory in the average test year and the projected cost at the end of 2025, and they propose to raise their coal inventory target for their plants to 35 days.

24. Coal inventory can be reduced by running the generation plants more.

25. FRR Companies in PJM may self-schedule to control their own generation.

Non-Rate Base Revenue Requirement Adjustments.

Stand-Alone Net Operating Loss Carryforward (NOLC)

26. The Companies' did not provide a comparison of West Virginia ratemaking for federal income taxes with that of other jurisdictions within which affiliates that obtained PLRs operate.

27. The Companies did not make available to the Commission the affiliates' explanation to the IRS why they would face a normalization violation.

28. The record in this case does not indicate whether the regulatory commissions in other states agreed or disagreed with the substance of the affiliates' requests for PLRs, offered their own defense of their federal income tax ratemaking treatment, and were allowed to participate in discussions with the IRS.

29. The Mountaineer request for the PLR and the IRS ruling were specific to ratemaking in West Virginia rather than in other states where AEP subsidiaries that received the rulings operate.

30. The argument that the Mountaineer ruling was "much different in substantive form and format from the AEP PLRs" is not persuasive considering that those PLRs were not specific to West Virginia.

31. Mountaineer did not agree with the Commission and told the IRS when it filed for the PLR that it believed that there was a normalization violation due to the Commission's ratemaking.

32. To the extent that accelerated depreciation that is required to be normalized by federal statute and IRS regulations is or has been available to the Companies and is available as a statutory adjustment in income tax calculations, it is our practice for ratemaking purposes that the tax effect of the statutory adjustment reflecting the difference between book and tax depreciation be added back to current income taxes to be included in rates paid by customers. In this way the Companies immediately receive the benefits of the accelerated depreciation in the form of cash payments in rates paid by customers regardless of a tax loss carryforward created by the consolidated AEP tax filing.

Parent Company Loss Adjustment (PCLA)

33. Beginning in 2014 the Commission changed its long-standing policy of calculating an effective income tax rate by comparing the actual normalized taxes, including the reduced taxes created by loss companies (excluding

accelerated depreciation in the losses) to the normalized taxes of companies in the consolidate income tax filings that had positive taxable income.

34. In the 2014 case, the Commission agreed to change its prior use of all loss companies and to depart from the use of an effective tax rate and instead use a PCL approach. Instead of calculating an effective tax rate the Commission agreed to allocate the average PCL to the West Virginia utility based on the utility's share of the taxable income in the years used for the averaging.

35. In this case the issue revolves around the amount of parent company tax loss allocated to West Virginia, a number that was a \$5.348 million deduction from taxable income in the 2014 case.

OPERATING INCOME AND OPERATION AND MAINTENANCE (O&M) EXPENSES

Generation O&M Adjustment

36. The Companies incurred \$164 million in generation O&M expenses in the test year 2023 and are forecasting higher expenses in the coming years. The Companies proposed an adjustment of \$8,295,326.

Distribution O&M Adjustment

37. The Companies requested an adjustment of \$5.2 million to increase the test year \$60 million of expenditures for distribution O&M.

38. The Companies need to increase pole attachments, pole inspections, and pole replacements to improve reliability and accommodate broadband expansion in West Virginia.

RATEMAKING MECHANISMS

Electric Rate Stabilization Surcharge (ERS)

39. The Electric Rate Stabilization Surcharge (ERS) incentive ratemaking proposal of the Companies would automatically increase the Companies' total revenues by up to three percent annually without a requirement to seek regulatory approval, and require a base rate case after four consecutive annual rate increases under the proposed ERS.

40. Electric rates are not comparable in magnitude and impact on customers to solid waste charges.

Vegetation Management Program (VMP)

41. VMP costs seem to be stabilizing.

RATE DESIGN

Jurisdictional Cost-of -Service (JCOS)

Allocation Factor Study

42. The Companies' demand/energy study allocation factors had errors including an incorrect factor to apportion APCo's peak demands between West Virginia and Virginia in the month of September 2023 which overstated the factor used to develop the production allocator for West Virginia.¹⁰⁹ The Companies agreed with Staff regarding the error.

Jurisdictional Allocation – Kingsport

43. The Companies' Kingsport demand values were not adjusted for losses like all other customers¹¹⁰ and the Companies failed to apply an energy loss adjustment.

44. Whether Kingsport is a wholesale customer, a retail customer, or an affiliate has nothing to do with adjusting measured demand and energy at the customer level back to generation levels. The loss factors are different for loads delivered at transmission, sub transmission and various distribution levels.

45. The Commission's practice is to adjust non-jurisdictional loads to generation levels for allocation purposes. That exercise also requires adjusting retail load to generation levels. Retail loss adjustment factors are also common in class cost of service studies.

Generation and Transmission Property Tax Allocation

46. The Board of Public works requires a tax filing that starts with net plant investment and the Tax Division, in determining value applies a capitalized earnings factor to determine the final taxable property value. That factor can range both up and down depending on the weight given to capitalized earnings.

¹⁰⁹ Initial Brief of Staff at p. 9 (Bates 16), July 17, 2025.

¹¹⁰ Initial Brief of Staff at p. 10 (Bates 17).

47. West Virginia Code Chapter 11 and Rule 4 of the West Virginia State Tax Commission's Valuation of Public Utility Property for Ad Valorem Property Tax Purposes, 110 C.S.R. 1M, provide guidance on valuation of operating public utility property.

Class Cost of Service

Special Contract Customers A, B, and G Revenue Adjustments

48. The purpose of Special Contracts is to allow special rates and terms based on the individual customers characteristics. We will keep the special contracts as separate rate classes unto themselves.

Revenue Distribution or Allocation and Rate Design

End of Test Year Customer Revenues Adjustment (Statement G, Adjustment 10-OR)

49. The Companies adjustment to end of test year revenues falls into the area of matching average test year rate base with average test year expense and revenue units.

50. The potential for a mismatch is high when adjusting units of expense and revenue.

Book-to-Bill Revenues Adjustment (Statement G, Adjustment 1-OR)

51. The Companies reconciled the revenue difference between billed and accrued revenue recorded on the Companies' books with the revenue generated by applying test-year billing determinants to test-year rates.¹¹¹ This was a shortcut to adjustment factors normally used.

Rate Design – Roll-in of MRBC Rates

52. The Companies did not object to Staff's proposal pertaining to an increase in customer charges for non-residential customers by the MRBC rate being rolled into base rates and then increased by Staff's percentage increases over current rates.¹¹²

¹¹¹ Cos. Exh. MMS-D at Bates 4619-20.

¹¹² Cos. Exh. MMS-D at Bates 286; Staff Exh. GMC-D at Bates 31.

ENEC and CRRRC Rate Updates

53. The Companies did not object to Staff's Adjustment No. 9 for APCo and Adjustment No. 10 for WPCo.¹¹³

Dollar Energy Fund

54. From 2020 through 2024, the Companies contributed \$250,000 in shareholder funds per year to the state Dollar Energy Fund (DEF).

55. The Companies did not make a ratepayer contribution to the DEF during this time period and are not requesting Commission consent or approval to use ratepayer money to contribute to the DEF in this case.

56. The Companies have also not committed to continue making a shareholder contribution to the DEF.

57. Monongahela Power Company and The Potomac Edison Company each have a \$500 DEF grant limit and a year-round application period.

Low-Income Residential Discount Rider

58. The Companies currently have a SRR-RS tariff that provides a twenty percent discount for residential customers meeting certain income qualifications, for the billing months of December through April, corresponding to the usage months of November through March.

Tariff Terms and Conditions

Removing Tariff Sheets 29-1 and 29-2 (Mitchell Base Rate Surcharge or MBRS)

59. The Commission did not intend the MBRS, which became effective January 1, 2020, and was created to reflect 100 percent of the costs associated with WPCo's ownership interest in the Mitchell plant,¹¹⁴ to be permanent. The Commission instead intended the MBRS to terminate in the next base rate case for the Companies.

¹¹³ Cos. Exh. MMS-R at Bates 283.

¹¹⁴ Appalachian Power Co. and Wheeling Power Co., Case No. 19-0564-E-T, Comm'n Order, Dec. 18, 2019.

Zeroing out the surcharge amounts in Tariff Sheet 45 (Modified Rate Base Cost Surcharge or MRBC)

60. The Companies requested this modification effective on implementation of new base rates.¹¹⁵

Reconnection Charge

61. The historic cost basis for a reconnection fee, including a site visit by field personnel, is no longer applicable.

62. There has been no analysis presented in this case of the current cost basis for reconnection fees.

Net Metering

63. The Companies proposed a new net metering tariff – NMS II.¹¹⁶

COGEN/SPP Tariff

64. The Companies provided no testimony to support a change in availability and payment provisions under the COGEN/SPP Tariff.

IV. CONCLUSIONS OF LAW

Capital Structure

1. The Commission determines a capital structure that (i) is reasonable, (ii) fairly balances the interests of current and future customers, the general interests of the State's economy and the interests of the utilities and (iii) produces the lowest reasonable overall revenue requirement that maintains financial integrity and flexibility for the utility.¹¹⁷ While it might appear that a heavily leveraged capital structure (high percentage of debt) is preferred, the Commission considers the end result of an over-leveraged capital, such as low-interest coverage, to arrive at a reasonable capital structure that is neither overly leveraged with debt nor overloaded on the equity side.

¹¹⁵ Cos. Exhs. RRS-D at Bates 3918-19, RRS-R at Bates 57, and MMS-R at Bates 294-95.

¹¹⁶ Cos. Exh. RAS-R at Bates 196-98.

¹¹⁷ Id. at 20.

2. The capital structure determination is not simple arithmetic or a simple science that must take the point in time or the average actual capital structure as reasonable in all circumstances.

3. The record in this case supports the 44 percent equity ratio recommended by the CAD. The use of the 44 percent based on the group of utilities reviewed by the CAD is reasonable and representative of the capital structure of those utilities. Moreover, the end result calculations presented by Staff demonstrate that the financial health of the Companies would not be impaired by a 44 percent equity capital ratio at the cost rates of debt and equity adopted herein.

Cost of Debt

4. If the Companies wish to propose identification of short term, or even long term debt in the future, based on differences in operating procedures and regulation in West Virginia and Virginia, they should provide a complete analysis of potential differences, not just the isolated accounts receivable issue.

5. Because there is no single point in time or multiple points in time over which to measure the debt cost and because the proposals by the Companies, the Staff, and the CAD all reflect the cost of debt of the Companies over various periods of time, it is reasonable to average the weighted cost of debt of the three parties and apply that to the 56 percent total debt. That average cost of total debt is 4.97 percent. It is not necessary to divide the interest cost between long-term debt and short-term debt because we are using the weighted cost of long-term and short-term and applying it to the 56 percent debt component of the capital structure.

Return on Equity

6. The final determination of a fair and reasonable return on equity is the Commission's decision, bound by evidence, current economic conditions, the legal precedents, and the results of the ROE on the financial condition of the Companies.¹¹⁸

7. The end result analysis for ROE is a test of reasonableness of any particular ROE result to satisfy the requirement that the return is sufficient to

¹¹⁸ Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of West Virginia, 262 U.S. 679, 692–93 (1923); Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944); Appalachian Power Co. and Wheeling Power Co., Case Nos. 14-1151-E-D and 14-1152-E-42T, Comm'n Order, May 26, 2015, at 16. Companies' Initial Brief at 6, July 17, 2025; West Virginia-American Water Co., Case No. 10-0920-W-42T, Comm'n Order at 18 (Apr. 18, 2011).

assure confidence in the financial soundness of the utility as required by the Bluefield and Hope cases.

8. The Commission should maintain a 9.25 percent ROE for the Companies because that level is supported by a complete evaluation of all of the DCF and CAPM data presented ably by the expert witnesses in this case with application of Commission judgement to those data.

RATE BASE

Cash Working Capital

9. The Companies point out in their initial brief that the Commission allowed depreciation in the cash working capital calculation in their 2014 rate case. The facts and circumstances leading to such a determination were the basis for the Commission decision at that time. The Commission decides each case based on the facts and circumstances applicable at the time a decision is made.¹¹⁹

10. We do not find justification in this case to include depreciation or profits on rate base as cash working capital. We will adjust cash working capital to reflect only the expense payment leads and revenue lags consistent with the cash expenditures for O&M expenses and taxes included in the final revenue requirements approved in this Order.

Period End Rate Base Adjustment

11. It is appropriate to roll into base rates all the Companies investment made in special surcharge cases up to the level of investment presented in the most recent surcharge filings (except for the Business Ready Sites Program Surcharge which will be address in Case No. 24-0956-E-IDS) because we were statutorily required to allow expedited rate treatment of certain investments in plant, or because we encouraged or required certain plant investments on grounds that they were in the best interests of customers. We allowed rate base treatment until further order of the Commission and will not remove that part of our commitment until the investments are fully rolled into the Companies' base rates.¹²⁰

¹¹⁹ The Chesapeake and Potomac Telephone Companies of West Virginia v. Public Service Commission of West Virginia, 300 S.E.2d 607,613 (1982).

¹²⁰ There may be some investment related to statutory or Commission-approved surcharge cases that were not included in the related cases now before us. We are authorizing the Companies to roll investment up to August 29 into base rates, eliminate surcharges and design base rates accordingly. We will, however, review those investments in the final true-up of the surcharge cases and require the Companies to provide

12. While the matching principal is not perfect, and there have been instances when the Commission departed from a strict adherence to the matching principal, except for specific categories of investment as discussed herein, this case does not present evidence or a compelling reason to depart from the average rate base matching principles.

Construction Work In Progress (CWIP) Inclusion in Rate Base

13. The Commission should not violate the matching principal by allowing the Companies' proposed rate base adjustment to include \$239 million in construction work completed and in service prior to January 1, 2025.

14. To the extent that the requested distribution or transmission CWIP includes projects included in special surcharge cases, it is appropriate to allow continuing recovery through the base rates or applicable surcharge mechanism, including a true up that will be required after the rates in this case go into effect.

15. The Legislature recently passed a new statute requiring the Commission to determine the extent to which the electric generating units in the state are prepared to maximize generation and to maintain generating plants to be able to achieve at least a 69 percent capacity factor.¹²¹ The legislation also requires the Commission to analyze action necessary to extend their useful lives.¹²²

16. In view of the goals which we and the West Virginia Legislature have set – which are to maintain the valuable base load, on-site inventoried fuel secure, dispatchable, coal-fired generation plants, the Commission should depart from the average rate base matching principal for the requested generation plant investments.

17. The Commission should allow the originally requested adjustment for CWIP investment in projects that were under construction in late 2024 and were not likely to be cancelled in consideration of the increased importance of the coal fired plants both for economic and reliability reasons.

Coal Inventory Adjustment

adequate proof that they were not duplicative, were consistent with the purpose of the surcharge case and were prudently incurred reasonable and necessary investments.

¹²¹ W.Va. Code §24-2-1d(f).

¹²² W.Va. Code §24-2-19(e).

18. Reasonable exercise of the PJM self-dispatch flexibility is a required element of prudence.

19. The Companies should maximize the use of their generation plants by scheduling plants when they believe that reasonably scheduled output over each daily scheduling period will not produce a significant out-of-pocket net cost based on only the truly variable costs of generation that are directly proportionate to output.

20. To provide headroom for inventory to cycle up during periods of low usage, low market prices, and plant downtime for planned and unplanned maintenance, and to cycle down during high market price periods, the Commission should approve the Companies adjustment to coal inventory and should not approve a 35-day maximum inventory target.

Non-Rate Base Revenue Requirement Adjustments.

Miscellaneous Adjustments

21. The Commission should approve Adjustment 43-AG to increase test year capacity performance insurance expense by \$255,893 as a result of increase in insurance premiums following Winter Storm Elliot

22. The Commission should normalize rate case expense by allowing one-third of the rate case expense in revenue requirements. The normalization adjustment does not authorize the Companies to carry forward an unamortized regulatory asset into future rate case expenses. If the Companies file another rate case in less than three years, the balance of prior rate cases, even if recorded on the books, will not be picked up as a regulatory asset. On the other hand, if the Companies do not file another rate case in three years they will continue to collect the normalization adjustment included in this case without any over-recovery concerns.

23. The Commission should not include the Adjustment 21-PE power production expense amortization in base rates. The Companies may include the expense as an ENEC expense and the amount allowed will be considered as part of the ENEC over or under recovery as an ENEC cost beginning in 2025.

Non-Rate Base Revenue Requirement Adjustments.

Depreciation and Asset Retirement Obligation (ARO)

24. The Commission should allow the ARO adjustments and depreciation for the same reasons expressed in the 2014 rate case order.¹²³

25. In the next base rate case the Companies should address the ARO adjustment and explain why it should not be adjusted due to additional payments from customers since the 2014 rate case.

Stand-Alone Net Operating Loss Carryforward (NOLC)

26. The Commission should not include the DTA in rate base because whether the utility or its consolidated tax group has a net taxable income or a net taxable loss and tax loss carryforward, our ratemaking does not require the DTA to escape a violation of normalization requirements.

27. Commission ratemaking complies with normalization rules because we do not include the benefits of book/tax timing depreciation differences that are required to be normalized in determining the income tax expense to include in rates. The Commission does not directly or indirectly flow through to ratepayers timing differences that are required to be normalized.

28. If the Companies decide to seek a PLR, they should officially inform this Commission in advance, provide us with the request before it is filed with the IRS, and seek Commission input into their request for the IRS ruling. Following Commission input, the Companies and the Commission may then inform the IRS that (1) the West Virginia Commission has reviewed the request and believes that the request with input from the Commission is adequate and complete; and (2) that the Companies will permit the Commission to participate in any Associate office conference with the IRS concerning the request.

29. To protect the Companies and their customers, the Commission should authorize the Companies to establish a regulatory asset equal to the return that would be associated with inclusion of an amount equal to the Companies' requested stand-alone Net Operating Loss Carryforward Deferred Tax Asset in the calculation of rate base, as well as the net excess amortization of excess Accumulated Deferred Income Taxes in the calculation of the cost of service in this case. The regulatory asset should be booked commencing on August 29, 2025. The Companies will be eligible to request recovery of that regulatory asset if they receive an IRS determination that the exclusion by this Commission of the standalone Net Operating Loss Carryforward Deferred Tax Asset from the calculation of rate base constitutes a normalization violation. If the IRS determines

¹²³ Appalachian Power Co. and Wheeling Power Co., Case No. 14-1152-E-42T, Comm'n Order, May 26, 2015, at 39.

that such exclusion does not constitute a normalization violation, the regulatory asset will be written-off and not recovered from customers.

Parent Company Loss Adjustment (PCLA)

30. The Commission should adopt the Staff calculation for PCL because the Staff determined the total positive taxable income of the Companies and compared that to the total positive income of the AEP consolidated group a comparison described by the Commission in the 2014 Order.

31. Because no reasonable alternative was presented by any party to this case, the Commission will not depart from the three-year average of positive normalized taxable income of the West Virginia jurisdiction and the total consolidated group for the allocation factor applied to the three year average PCL as calculated by Staff.

Corporate Alternative Minimum Tax (CAMT)

32. The Commission should not impute a CAMT because The minimum would not apply to the Companies on a standalone basis, and whether a CAMT would apply to the consolidated AEP group in the future is purely speculative. Moreover, how to reasonably allocate a CAMT of the AEP consolidated group to West Virginia would require more than the speculative information available in this case.

33. The alternative suggested by the Companies to defer any difference between the actual CAMT incurred by the Companies and the amounts reflected in base rates. We find that to be reasonable, particular considering that we have required the effects of extensive tax law changes to be deferred and reviewed by the Commission for rate treatment outside of base rate cases. The amount deferred, if any, will be subject to review and the Companies will have the burden to show that the deferred amounts are correctly assigned to West Virginia or reasonable allocable to West Virginia. The Commission will consider the deferred amount for reasonableness, applicability and appropriate rate treatment when the Companies propose an amortization in future proceeding

OPERATING INCOME AND OPERATION AND MAINTENANCE (O&M) EXPENSES

Generation O&M Adjustment

34. The Commission should include the Companies' generation O&M expenses of \$164 million incurred in the test year 2023 as well as the \$8,295,326

upward adjustment for the same reasons discussed in the section above titled Construction Work In Progress (CWIP) Inclusion in Rate Base regarding capital expenditures on the power plants.

35. The Commission should require the Companies to provide a report on actual test year generation O&M, by account and plant, going-level generation O&M allowed herein, by account and plant, and actual incurred generation O&M, by account and plant, in each future ENEC filing, or any other case if requested by the Commission.

Distribution O&M Adjustment

36. The Commission should approve the \$5.2 million adjustment to distribution system O&M for the Companies to spend productively on the distribution network.

37. To encourage improved maintenance of poles and expedited replacement, the Commission should add \$2.0 million in the Distribution O&M adjustment for pole inspections and maintenance a substantial portion of which the \$2.0 million should be dedicated to hiring additional inspection crews that can also serve to participate in service restoration when needed after wide-area outages. The Commission should also authorize an additional \$20.0 million rate base adjustment to be dedicated to pole replacements.

38. The Commission should require the Companies to file future reports showing additional pole maintenance and replacement activities in the future. Specifically, the Companies should file a report within sixty days of the date of this order showing pole maintenance and numbers of inspections by year over the last three years. Thereafter they must file a report every May and November showing the same information for six months ending March and September prior to the report date.

Long-Term Incentive (LW) Compensation

39. The Commission should include 50 percent of the Companies' proposed cost of long term pay incentives, exclude the Companies' proposed stock incentives, and exclude \$253,000 from revenue requirements in this case.

Severance Costs

40. Severance costs are one-time expenses that should not be included in revenue requirements.

RATEMAKING MECHANISMS

Electric Rate Stabilization Surcharge (ERS)

41. The Commission should will deny the Companies' proposal because it departs too much from cost-based ratemaking at too high a price. The ERS proposal is not similar to surcharges that the Commission has utilized for electric utilities for limited, specific costs that are provable and then trued-up at the end of one or two years.

Environmental and New Generation Surcharge (ENG)

42. The Commission should approve the Companies recommended ENG to replace the Environmental Compliance Surcharge and the Renewable Energy Tariff.¹²⁴

Vegetation Management Program (VMP)

43. The Commission should eliminate the vegetation management surcharge and add the current approved costs of the program back into base rates costs because VMP costs seem to be stabilizing.

44. To true up the VMP surcharge amount collected since the last VMP true up, the Companies should file, with their next ENEC case, an accounting of the VMP surcharge through August 28, 2025.

45. The Companies should continue to maintain vegetation management at the same level as today and on a four-year cycle. Additionally, the Companies should spend the entire amount of funds each year that are currently allotted in the VMP surcharge or more.

46. The Companies should file, every six months, a report accounting for the amount of money they spent during that period on vegetation management on the same schedule as required for pole maintenance, replacements, and inspections. If vegetation management expenditures decrease, the Commission will consider a show cause proceeding designed to establish a more formal and mandatory vegetation management expenditure program in conjunction with targets for reliability indices that contain incentives and penalties.

¹²⁴ Companies Initial Brief at p. 26, July 17, 2025.

RATE DESIGN

Jurisdictional Cost-of -Service (JCOS)

Allocation Factor Study

47. The Commission should adopt the demand/energy study allocation factors recommended by Staff.

Jurisdictional Allocation (Kingsport)

48. The Commission should adopt Staff's adjustment of the Kingsport demand values in the Companies' demand/energy study by a loss factor of 3.31 percent, and adopt the Kingsport energy values in the study by a loss factor of 2.96 percent.

Generation and Transmission Property Tax Allocation

49. The Commission should adopt the Staff approach regarding jurisdictional cost allocations for transmission and production costs and rate base to all customers because the same allocation of property tax should apply for transmission lines that serve customers throughout the service territory of the Companies and utilities in neighboring states.

Class Cost of Service

Production Plant Allocation

50. The Commission should adopt cost allocation of production plant based on a 12 CP theory rather than the Average and Peak method.

Special Contract Customers A, B, and G Revenue Adjustments

51. The Commission should keep the special contracts as separate rate classes unto themselves because the purpose of special contracts is to allow special rates and terms based on the individual customers characteristics.

Revenue Distribution or Allocation and Rate Design

End of Test Year Customer Revenues Adjustment (Statement G, Adjustment 10-OR)

52. The Commission should allow 50 percent of the Companies proposed adjustment to end of test year revenues because the Companies did not show the potential cost reductions associated with changes in revenue units.

Special Contract Base Rate Revenues (Staff Adjustment 8)

53. The Commission should not modify the test year special contract revenue as proposed by Staff.

Book-to-Bill Revenues Adjustment (Statement G, Adjustment 1-OR)

54. The Commission should reject the Companies adjustment to book-to-bill revenues and adopt the Staff calculations.

Rate Design Issues under Rate Schedules SWS (Sanctuary Worship Service) and GS (General Service)

55. The Commission should adopt the Companies' normalization approach for rate schedules SWS and GS which is better at smoothing normalization.

Rate Design – Elimination or Change to 10kW Maximum Demand Limitation in Rate Schedule SGS

56. The Commission should continue the 10kW maximum demand limitation in Rate Schedule SGS.

Rate Design – Elimination or Change to 10kW Maximum Demand Limitation in Rate Schedule SGS

57. The Commission should not approve a demand change in commercial rate schedules that could result in unexpected increases, but would consider such a proposal or a phase-in proposal if presented in a separate income neutral tariff filing.

Rate Schedule RS Time-of-Day (TOD) Recommendations

58. Schedule RS-TOD's basic service charge should be set at the same rate as Schedule RS basic service charge rate to better align with cost-causation principles and eligible customers should be allowed concurrent participation in Schedules RS-TOD and SRR-RS assuming that those customers are eligible to participate in Schedule SRR-RS. The Companies should analyze the Schedule RS-TOD to adjust the on-peak window to four or fewer hours to encourage

customer load shifting and realized savings. The Companies should further analyze this issue and file proposed tariff changes in a new docket filing on or before July 1, 2026.

LED Lighting

59. The Companies should recalculate the ownership cost rate component for LED lighting options under Schedule OL and Schedule SL using an assumed lifetime of fifteen years and without a removal cost component.

Residential Winter Tail Block

60. The Companies should reduce the residential winter tail block threshold to 1,100 kWh from the current 1,350 kWh and extend the winter tail block to include March.

Dollar Energy Fund

61. The Commission should encourage the Companies to continue participation in the DEF. To aid customers needing this assistance and because the Companies have not committed to a shareholder contribution beyond 2024, the Commission should include in base rates a \$1 million revenue requirement and require the Companies to contribute that amount to DEF. The full amount should be contributed prior to the beginning of the upcoming winter period.

62. The Commission should require the Companies to increase their grant limits from \$300 to \$500 per customer per year and allow applications year-round instead of only December through March, and the Companies should file a closed entry in this case informing the Commission that the changes were made. If the DEF declines to make the changes, the Companies should file a closed entry in this case informing the Commission why the DEF will not make these changes.

Low-Income Residential Discount Rider

63. Because W. Va. Code §24-2A-1 et seq. permits the special discounted rates only during December through April, the Commission is unable to modify the effective date of the SRR-RS tariff.

64. The Commission should consider alternative funding for a low-income discount through a revenue requirement shared by all customers. The Commission should require the Companies to prepare an analysis of the expected revenue requirement of a twenty percent discount for qualified customers in the months of July and August, and file the estimate by November 1, 2024.

Revisions to Tariff Sheet 3-10

65. The Commission should deny the Companies' requested change to the definition of "permanent dwelling."

Changing "legally observed holidays" to "legal holidays"

66. The Commission should not approve changing "legally observed holidays" to "legal holidays".

Removing Tariff Sheets 29-1 and 29-2 (Mitchell Base Rate Surcharge or MBRS)

67. The MBRS should be terminated and this surcharge should be rolled into base rates.

Removing Tariff Sheet 44 (Tax Reform Rider or TRR)

68. Tariff Sheet 44 should be removed because the TRR is no longer available.

Reconnection Charge

69. Because there has been no analysis presented in this case of the current cost basis for reconnection fees, it would be unreasonable to eliminate the reconnection charge completely. The Commission should require the Companies to modify their tariffs to reduce reconnection fees by fifty percent. In the next base rate filing, the Companies' should file a cost analysis to justify a reconnection fee or request that the fee be eliminated.

Net Metering

70. Because the net metering tariff methodology proposed by Mr. Eads is just and reasonable, the Commission should approve Staff witness Eads' methodology. The Companies should use Mr. Eads' methodology to calculate the new tariff.

71. To provide sufficient notice to customers, the Commission should adopt a deadline of twelve months from the date of this Order for customers to file initial net metering applications to fall under the current NMS Rider. Residential customers should have twelve months, and commercial customers should have

eighteen months, to receive certificates of completion and continue to be eligible for the current NMS Rider.

COGEN/SPP Tariff

72. The Commission should not approve a rate design change at this time.

CONCLUSION

73. The Commission should approve securitization in a separate Order to result in the capitalization of a large portion of the investment approved in this base rate case and a large portion of deferred costs currently capitalized by the Companies' current capital sources at lower capital costs, thereby reducing rates.

74. All rate base, revenues and costs included in the various surcharge cases under review this year should be rolled into base rates. Except for the Companies' Business Ready Sites Program investment¹²⁵, the roll in should include the levels of those surcharge-recoverable rate base and expenses through the most recent data included in the various recent surcharge filings. The Commission should initiate a true up proceeding when all costs that were formally recoverable in the surcharge cases are known and provide a mechanism that will recover those costs without an annual surcharge proceeding going forward.

75. Because of the necessary delay between this Order and a determination of the final rate reductions that will accompany securitization, the Commission should require a deferral mechanism for the base rate increase that would otherwise have been required upon the issuance of this Order. Accordingly, the Commission should require that the revised tariff that the Companies file pursuant to our decisions herein maintain present base rates, unchanged and add the new base rates increases as identifiable deferrable increments.

76. The Companies should continue to bill customers at the current rates with no increase on customer bills resulting from this decision.

77. The Companies should calculate the monthly base rate increase that equates to the results of this Order and recover that amount from the ENEC surcharge billings to allow current recovery of the base rate revenue requirements without special deferral.

¹²⁵ Roll-in of the Companies' investment in the Business Ready Surcharge Program will be addressed in Case No. 24-0956-E-IDS.

78. Impacts from this Order on the ENEC deferral should be addressed in an ENEC true up prior to the final securitization implementation in time to determine the ENEC under-recovery deferral balance to roll into the securitization.

ORDER

IT IS THEREFORE ORDERED that the Commission shall approve for Appalachian Power Company and Wheeling Power Company a revenue rate requirement of \$76.1 million as reflected in this Order and supported by Appendices A and B attached hereto.

IT IS FURTHER ORDERED that the Companies shall design revised tariffs, consistent with the decisions in this Order, that the Companies shall file pursuant to our decisions herein, maintain the present base rates unchanged, and add the new base rate increases as identifiable deferrable increments. The Companies shall continue to bill customers at the current rates so that there is no increase on customer bills resulting from this decision.

IT IS FURTHER ORDERED that the Companies shall calculate the monthly base rate increase that equates to the results of this Order and recover that amount from the ENEC surcharge billings.

IT IS FURTHER ORDERED that the Commission authorizes the Companies to roll investments and expenses reported in the most recent surcharge filings into base rates, eliminate all current surcharges, except the Business Ready Sites Program surcharge which is required by statute and which will be address in Case No. 24-0956-E-IDS, and design base rates accordingly.

IT IS FURTHER ORDERED that the Companies shall, in their next base rate filing, address the Asset Retirement Obligation adjustment and depreciation on Asset Retirement Obligation assets, and explain why it should not be adjusted due to additional payments from customers since Case No. 14-1152-E-42T.

IT IS FURTHER ORDERED that the Companies must file a report within sixty days of the date of this order showing pole maintenance and numbers of inspections by year over the last three years. Thereafter they must file a report every May and November showing the same information for six months ending March and September prior to the report date.

IT IS FURTHER ORDERED that the Companies shall file, every six months , a report accounting for the amount of money they spent on vegetation

management during the prior six months. The report shall be filed using the same schedule as required for pole maintenance, placement, and inspections.

IT IS FURTHER ORDERED that the Companies shall continue to maintain vegetation management at the same level as today and on a four-year cycle.

IT IS FURTHER ORDERED that the Companies shall analyze the Schedule RS-TOD to adjust the on-peak window to four or fewer hours to encourage customer load shifting and realized savings and file proposed tariff changes on or before July 1, 2026.

IT IS FURTHER ORDERED that the Companies shall recalculate the ownership cost rate component for LED lighting options under Schedule OL and Schedule SL using an assumed lifetime of fifteen years and without a removal cost component.

IT IS FURTHER ORDERED that the Commission shall approve the Commission Staff proposal for an increase in customer charges for non-residential customers by the MRBC rate being rolled into base rates and then increased by Staff's percentage increases over current rates. The Companies shall reflect the Staff rate design in developing rates consistent with this Order.

IT IS FURTHER ORDERED that the Companies shall make a closed case filing in this case informing the Commission that changes to the Companies' contributions into the Dollar Energy Fund and increases in Dollar Energy Fund grants for payment of the Companies' bills, as discussed in this Order.

IT IS FURTHER ORDERED that the Companies shall file, on or before November 1, 2025, an analysis of the expected revenue requirement of a twenty percent discount in the months of July and August. To be clear, the Commission is not ordering a tariff discount, but merely an informational filing as to what the cost impact would be for such a program.

IT IS FURTHER ORDERED that the Companies shall modify their tariffs to reduce reconnection fees by fifty percent.

IT IS FURTHER ORDERED that, with the Companies next base rate filing, they shall file a cost analysis to justify a reconnection fee or request that the fee be eliminated.

IT IS FURTHER ORDERED that the Companies shall allow customers who want to participate in the current net metering tariff to file an initial net metering application on or before March 1, 2026.

IT IS FURTHER ORDERED that the deadlines for customers of the Companies to receive certificates of completion and continue to be eligible for the current NMS Rider are September 1, 2026 for residential customers and March 1, 2027 for commercial customers.

IT IS FURTHER ORDERED that if the Companies decide to file with the Internal Revenue Service for a Private Letter Ruling on the Stand-Alone Net Operating Loss Carryforward issue, they should inform this Commission in advance by seeking Commission input into the request for an IRS ruling as further discussed in this Order.

IT IS FURTHER ORDERED that upon entry of this Order this case shall be removed from the Commission docket of open cases.

IT IS FURTHER ORDERED that the Executive Secretary of the Commission serve a copy of this Order by electronic service on all parties of record who have filed an e-service agreement, by United States First Class Mail on all parties of record who have not filed an e-service agreement, and on Commission Staff by hand delivery.

A True Copy, Teste,

A handwritten signature in cursive script that reads "Karen Buckley".

Karen Buckley,
Executive Secretary

SMS/pkb
240854cg.sca

Appendix A

	APCo	WPCo	Total
Rate Base	\$4,260,285,797	\$839,670,622	\$5,099,956,420
Rate of Return	0.068364	0.068364	0.068364
Return	\$291,250,178	\$57,403,242	\$348,653,420
O & M Expense	\$1,057,153,527	\$300,089,646	\$1,357,243,173
Depreciation	\$242,217,158	\$47,649,972	\$289,867,130
Taxes Other Than Income	\$83,941,023	\$19,622,162	\$103,563,185
Federal Income Taxes	\$38,154,370	\$12,700,337	\$50,854,707
State Income taxes	\$2,956,037	\$2,191,801	\$5,147,837
Other	\$3,145,043	\$652,203	\$3,797,247
Additional Uncollectibles	\$314,698	\$8,440	\$323,138
Total Revenue Requirements	\$1,719,132,035	\$440,317,802	\$2,159,449,837
Going Level Revenue	\$1,652,302,581	\$431,056,665	\$2,083,359,246
Increase	\$66,829,454	\$9,261,137	\$76,090,591

Appendix B

Description	Commission Adjustment	Revenue Requirement	
		\$ 49,328,394	Staff Recommended
Adjust Capital Structure	\$ (7,732,517)	\$ 41,595,877	
Allow Production Plant Adjustment	\$ 4,492,334	\$ 46,088,211	
Allow Companies' Coal Inventory	\$ 7,179,105	\$ 53,267,316	
Include ARO Adjustment	\$ 2,914,317	\$ 56,181,633	
Allow Companies' Generation O&M Adjustment	\$ 8,332,255	\$ 64,513,888	
Allow Companies' Distribution O&M Adjustment Plus \$2.0 million	\$ 7,229,434	\$ 71,743,322	
Commission Adjustment To Include Additional \$20.0 million Distribution Rate Base	\$ 1,623,425	\$ 73,366,746	
Allow 50% of Companies' Requested Incentive Pay Less Stock Bonus	\$ 1,402,604	\$ 74,769,350	
Allow 50% of Companies' Customer Count Adjustment	\$ 980,504	\$ 75,749,854	
Remove Staff Adjustment #8 To Revenue	\$ 1,113,175	\$ 76,863,029	
Allow Companies' Weather Normalization Adjustment	\$ 1,137,148	\$ 78,000,177	
Commission Adjustment to Provide \$1.0 million For Dollar Energy Fund	\$ 1,004,731	\$ 79,004,908	
Commission Adjustment To Staff Proposed Depreciation Expense	\$ (2,801,142)	\$ 76,203,766	