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APPALACHIAN POWER
An AEP Company
BOUNDLESS ENERGY

Keith D. Fisher
Senior Counsel

200 Association Drive, Suite 201
Charleston, WV 25311
304.348.4154
kdfisher@aep.com

August 10, 2026

Via Electronic Filing
Karen Buckley
Executive Secretary
Public Service Commission of West Virginia
201 Brooks St.
Charleston, WV 25301

Re: Case No. 26-0633-E-GI

Initial Comments of Appalachian Power Company and Wheeling Power Company

Dear Ms. Buckley:

Appalachian Power Company and Wheeling Power Company (together, the "Companies") respectfully submit their Initial Comments in response to the Commission Order and Proposed Rules filed in the above-referenced matter on July 20, 2026.

Please note my appearance and the appearance of my co-counsel, Kurt L. Krieger and Todd M. Swanson, as counsel for the Companies in this matter and include us on the electronic service list.

Thank you for your attention to this matter.

Sincerely,

Keith D. Fisher (WV State Bar #11346)
Counsel for Appalachian Power Company and Wheeling Power Company

Enclosure

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APCO/WPCO INITIAL COMMENTS

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 26-0633-E-GI

General Investigation into Adopting and Implementing Rules Governing Electric Generating Capacity

INITIAL COMMENTS OF APPALACHIAN POWER COMPANY AND WHEELING POWER COMPANY

Appalachian Power Company ("***APCo***") and Wheeling Power Company ("***WPCo***") (jointly, the "***Companies***"), pursuant to the Commission's July 20, 2026, order initiating this proceeding ("***Order***"), hereby submit their initial comments on the Commission's proposed rules attached to the Order and issued pursuant to *W. Va. Code* § 24-2-1d (sometimes referred to herein as "***HB 2014***"), which proposed rules are designated as *W. Va. Code R.* § 150-41-1 *et seq.* ("***Proposed Rules***" or "***PR***").

EXECUTIVE SUMMARY

The Companies wholeheartedly support maximizing "the production of electricity from their generating units when such self-generation will result in reduced energy costs for West Virginia ratepayers." W. Va. Code § 24-2-1d(f). But from the outset, the Proposed Rules exceed the scope and authority of *W. Va. Code* § 24-2-1d and, ultimately, will result in *increased* energy costs for West

Virginia ratepayers. The Commission was tasked with proposing rules "to carry out *its* duties and obligations as set forth [in W. Va. Code § 24-2-1d]," that is, to review the "consumer economic dispatch" of electric generating facilities in West Virginia. *Id.* (emphasis added). What has been proposed, however, is a slew of expensive, unnecessary, and duplicative reporting obligations on electric utilities and, even worse, requirements that restrict the utilities' ability to contract for coal in the day-to-day, ordinary course of business, and seem to be intent on potentially forcing the Companies' thermal units to run contrary to economic dispatch. This is not what the Legislature intended or authorized.

In this document, the Companies will provide both overarching comments highlighting significant issues with the effects of the Proposed Rules and more specific comments on individual portions that are problematic for a variety of reasons. The Companies will also address the Commission's non-compliance with the West Virginia Administrative Procedures Act, *W. Va. Code* § 29A-3-1 *et seq.* The Companies urge the Commission to rescind the Proposed Rules, subject to possible revision and resubmittal after stakeholder input, and would urge the Legislature to reject the Proposed Rules as currently written.

The Companies' comments should not be construed as reluctance to provide the Commission with data on their thermal units. The Companies already provide vast amounts of such data in their annual ENEC proceedings and through ongoing closed-case filings as ordered by the Commission in those proceedings. The Companies would gladly provide the Commission with relevant, meaningful

data, as well as explanation as to how the Companies interact on a daily, monthly, and annual basis with PJM to maximize the economic dispatch of their thermal units; indeed, in these initial comments, the Companies recommend some initial next steps to achieve that far better than finalizing and promulgating the Proposed Rules. The Companies submit that finalizing the Proposed Rules at this juncture would not be successful in providing the Commission with both the understanding and useful data it needs to carry out its regulatory obligations, generally, and under HB 2014.

The undue burden of the monthly reporting requirements in the Proposed Rules far outweighs any purported benefit and will come at great cost. The Companies anticipate needing to hire additional personnel *whose sole job* would be to prepare the monthly reports, if they could even be prepared within 10 days of month end; that timeframe appears virtually impossible even with increased staffing. The Proposed Rules are an expensive vehicle for the rote collection of vast amounts and types of data, overlooking any explanation, understanding, or examination of the purposes behind the Companies' dispatch activities within PJM; and, consequently, should not be promulgated until the Commission, the Companies, other West Virginia electric utilities, Staff, and CAD obtain the benefit of in-person workshops to exchange information and allow for questions and answers that first breed understanding, potentially replacing the proposed monthly production, collection, and submittal of what may well be meaningless data under

the Proposed Rules. The Companies recommend such workshops in these initial comments prior to any finalization and promulgation of final rules.

While the Legislature, like the Commission and Companies, supports the maximum dispatch of thermal units within the very real operational, economic, cost, demand, and market limitations so that West Virginia electric customers are not required to pay for uneconomic dispatch, the Companies do not believe that the Legislature contemplated eight pages of single spaced Proposed Rules that impose an incredibly burdensome monthly data collection exercise – as stated, an effort for which the Companies are not currently staffed and for which the Commission itself is also not likely staffed to comprehensively review, or at least not review on a monthly basis.

In addition, the Proposed Rules far exceed what is necessary or required by HB 2014 and, in some very important respects, directly conflict with the statute. The Legislature expressly sought to avoid any "increase in the charge or charges for electric energy" from operating "at a sixty-nine percent capacity." W. Va. Code § 24-2-1d(f). Yet, the Commission attempts to mandate a minimum 69% capacity factor in Proposed Rule 5.3, even after it entered into a consent decree in federal court agreeing not to do so.[1] And whether intended or not, forcing West Virginia

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[1] *Bruce Perrone, Rosanna Long, and Sierra Club v. Chairman Charlotte R. Lane et al., and Appalachian Power Co., et al.*, Civil Action No. 2:24-cv-00434 (U.S. Dist. Ct., So. Dist. Of West Virginia). *See* "APCo/WPCo Attachment 6" provided herewith.

electric utilities to self-schedule their units by way of Proposed Rules 4.4 and 5.3.2 is directly contrary to economic dispatch (if not also PJM and Federal Energy Regulatory Commission ("***FERC***") jurisdictional subject matters) and, therefore, conflicts with HB 2014, not to mention it will unnecessarily increase costs for West Virginia customers.

The Companies are offering herein some background and context as well as general and specific feedback about the Proposed Rules. Sections A through E below offer some overarching context in which to consider the Companies' initial comments, and Section F contains specific comments on the Proposed Rules. With respect to the latter, the Companies are also attaching a red-lined version of the Proposed Rules as "APCo/WPCo Attachment 1," which sets forth the Companies' specific edits to the Proposed Rules consistent with these initial comments.

"Affordability" has understandably become the guiding mantra around many essential products and services for everyday life, including electric service provided by the Companies to their customers. This includes not only ensuring the economic dispatch (or "consumer economic dispatch") of thermal units, but also avoiding the expanded cost of monthly compiling and reporting voluminous data sought by the Proposed Rules.

Consequently, in addition to its other general and specific comments herein, the Companies recommend:

- At the very least, any compiling and reporting of the types of data sought by the Proposed Rules should only be required to be reported on an annual basis as part of the Companies' annual ENEC filings where the Companies already report voluminous data about all of their thermal and other electric generating units, their fuels, and their dispatch, where data sought by the Proposed Rules can be presented along with other voluminous and corresponding data already contained in those ENEC filings.

- The convening and conducting of workshops and resolution of Case No. 25-0450-E-GI (the FRR/RPM general investigation) should come first prior to any finalizing and promulgating of rules under HB 2014.

- Given the greater extent to which gas units are economically dispatched both nationally and with respect to the Companies, to the extent the Proposed Rules seek any data pertaining to gas units or the procurement of gas, such data should be deleted from (or not required by) the Proposed Rules.

INITIAL COMMENTS

A. Maximizing the ***Economic*** Use of Generating Units

1. *W. Va. Code* § 24-2-1d(f) provides: "Electric utilities shall be prepared to maximize the production of electricity from their generating units when such self-generation will result in reduced energy costs for West Virginia ratepayers."

2. The Companies – as owners and operators of coal and gas-fired electric generation units in West Virginia together serving nearly 460,000 customers – wholeheartedly support this objective and have been operating to achieve that very objective.

3. *W. Va. Code* § 24-2-1d(f) further 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 operating a generating unit at a sixty-nine percent capacity if doing so will cause an increase in the charge or charges for electric energy . . . .*" (emphasis added).

4. The Legislature expressly recognized the importance of economics in running the plants and the attendant benefits to customers. But the Proposed Rules run counter to the letter and spirit of the statute, notably in the following sections:

a. **PR 5.3.** Capacity Factor. -- The Commission expects generating electric utilities subject to the rate jurisdiction of the Commission to maintain their generation plants and schedule maintenance to minimize down time *to allow it to achieve a minimum capacity factor* of sixty-nine (69%) percent. The success *in achieving a minimum capacity factor* will initially be measured over a twelve-month period. (emphasis added)

b. **PR 5.3.2.** The utilities are expected to take advantage of PJM Manual 11 Market Rules 2.3.3., *et seq.*, which allow self-scheduling rather than allowing PJM to accept or reject their output into the day-ahead market. The utility is not expected to operate at a net-positive margin in all hours of the day. It is expected to reasonably anticipate and project expected day-ahead market prices and schedule increments of generation to minimize negative margins during periods of low market prices

while allowing for reasonable, and limited ramping of generation levels as market prices fluctuate in the day-ahead market.

c. **PR 4.4.** Alternative. -- If a utility subject to this rule has chosen not to self-schedule all or any of its generation capacity during any day or portions of a day it shall explain why it made that decision. This explanation must be included in its monthly Generation Dispatch Report.[2]

5. The effect of these sections, particularly when taken together, is to upend the economic dispatch model in favor of self-scheduling units with the goal of achieving a minimum 69% capacity factor. As the Companies have explained in past Commission proceedings, including their recent 2026 ENEC proceeding (Case No. 26-0469-E-ENEC) ("***2026 ENEC Proceeding***"), self-scheduling is an important tool that is used *carefully in limited circumstances* for customers' benefit; it is not the norm. The norm is economic dispatch. And as mentioned above, the Commission is potentially attempting to use the Legislature to approve that which it has expressly agreed not to do: mandate a minimum capacity factor regardless of economics.[3]

6. The Companies will expand on this more in the subsections below.

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[2] The Commission's proposed definition of "self-schedule" recognizes that it "is *not* dependent on economic dispatch control by PJM." PR 2.11 (emphasis added).

[3] *See infra* n. 1 and Attachment 6 hereto.

B. Consumer Economic Dispatch and the 69% Capacity Factor

7. HB 2014 (*W. Va. Code* §§ 24-2-1d(e) and (f)) leans on two important concepts: "consumer economic dispatch" and not operating a thermal unit at a 69% capacity if doing so will increase customers' rates.

8. In addition, the definition of "consumer economic dispatch" in HB 2014 (*W. Va. Code* § 24-2-1d(d)), and incorporated into the Proposed Rules (PR 2 Preamble), appropriately references that such dispatch must also consider "the operational limits of generation."

9. The desire to "maximize" the use and operation of the thermal units *must* take into account market economics and the operational limitation of the units, both practically and legally. However, Proposed Rules 4.4, 5.3, and 5.3.2 do not.

10. The discretion and decision to run any given unit is not solely the Companies or outside of practical limitations. Instead, unit operating levels are primarily determined by two factors: (a) the unit's operational availability, which depends on required maintenance and improvement activities that must be scheduled through PJM's outage coordination process, and (b) PJM's dispatch of the unit, which depends on system demand and the unit's economic competitiveness.[4]

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[4] A requirement of HB 2014 and *W. Va. Code* §§ 24-2-1d(c) and (f) is that, in the use and dispatch of electric generation facilities, customers' utility rates be kept "as low as possible;" and "Nothing herein shall require a utility to operate a generating unit at sixty-nine percent capacity if doing so will cause an increase" in customers' rates.

11. These factors are subject matters upon which the Companies provide substantial factual information to the Commission in their annual ENEC proceedings, and which are thoroughly explored, scrutinized, challenged, and litigated in those same proceedings. For this reason, the information requested by the Proposed Rules is best provided along with the voluminous amount of information already provided in annual ENEC proceedings, and soon to be provided in closed-case IRP filings[5], regarding the Companies' thermal units, their operation, outages, availability, dispatch, and fuel procurement and costs.

12. As evidenced by the Companies' ENEC proceedings (most recently in the 2026 ENEC Proceeding) with respect to the operational availability, the Companies' gas and coal units have an Equivalent Availability Factor ("***EAF***")[6] that

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[5] *See* "APCo/WPCo Attachment 2" hereto.

[6] All definitions in the Proposed Rules should conform to industry-accepted definitions. For example, as Companies' witness Bumgarner states in his prepared direct testimony at Bates 37 in the 2026 ENEC Proceeding: "EAF is an unweighted (time based) performance metric defined in Appendix F of the NERC 2024 GADS Data Reporting Instructions as the ratio of a generating unit's available hours to the number of hours in the period being measured, expressed as a percentage. It represents the percentage of time in a specific period when the unit was available to operate at its rated output, regardless of whether it actually operated." Witness Bumgarner, in footnote 1 of that testimony, then offers the precise formula for EAF:

> [1] The equation for EAF is:
> Equivalent Availability Factor – EAF
>
> $$EAF = \frac{AH - EPDH - EUDH - ESEDH}{PH} \times 100\%$$
>
> EAF = Equivalent Availability Factor, AH = Available Hours, EPDH = Equivalent Planned, Derate Hours, EUDH = Equivalent Unplanned Derate Hours, ESEDH = Equivalent Seasonal Derate Hours, and PH = Period Hours.
>
> The definition for EAF is from Appendix F of the NERC 2026 GADS Data Reporting Instructions (https://www.nerc.com/globalassets/programs/rapa/gads/conventional/appendix_f_equations_2026.pdf)

exceeds 70% in the aggregate, with certain baseload units experiencing an EAF greater than 90% during some months.

13. With respect to ensuring the availability of the Companies' coal units, the Companies already provide extensive information on specific maintenance and investments they are making in the coal units to not only ensure their availability but to extend their useful lives well into the future.[7]

14. And, pursuant to the proposed "Joint Stipulation and Agreement for Settlement" filed on July 15, 2026 in Case Nos. 25-0859-E-IRP and 25-0860-E-IRP ("***IRP Settlement***"), the Companies propose to provide similar information about the coal units *on an annual basis* until the filing of the Companies' next IRP in 2030. *See, e.g.*, IRP Settlement § 10.h. A copy of that Joint Stipulation is provided herewith as "APCo/WPCo Attachment 2."

C. Affordability and PJM Dispatch; FRR/RPM Proceeding; Proposed Workshops

15. The Companies are focused on the affordability of electric service in West Virginia. For this reason, the Companies recently agreed to accept the Commission's proposal to forego the filing of a Rule 42T base rate case and, instead, adopt a modest, inflation-based increase to the Companies' base rates.[8]

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[7] *See* Exhibits E-1 through E-8 attached to each of APCo's (at Bates 163-201) and WPCo's (at Bates 152-163) October 1, 2025, IRP filings in Case Nos. 25-0859-E-IRP and 25-0860-E-IRP ("***IRP Proceeding***"). "APCo Generation utilizes a power plant maintenance strategy that blends prevention, prediction, and correction for enhanced reliability *and affordability*. Power plant maintenance must strike a crucial balance between ensuring operational reliability *and minimizing costs*." APCo's Exhibit E-1 at Bates 163.

[8] *See* Case No. NOIR APCO and WHEELING 26A.

16. The Commission must balance the interests of utilities, their customers, and this State in carrying out its regulatory duties. *W. Va. Code* § 24-1-1(b). Customer affordability should be a chief concern in this balancing act.

17. The goal of HB 2014 is to maximize use of the Companies' coal and gas units on a basis that is *affordable* to the Companies' customers. That means adhering to sound economic principles and PJM market guidelines that ensure those units are only dispatched when doing so does not increase costs to the Companies' West Virginia customers; that is, to avoid requiring the recovery of losses from uneconomic dispatch from West Virginia customers.

18. The Companies are most mindful of and were concerned with the Commission's statement in the Companies' most recent Rule 42T proceeding that perhaps the Commission misunderstood fixed resource requirement ("***FRR***") status and self-scheduling of units in PJM.[9]

19. However, the Companies were pleased that the Commission more recently recognized in the 2026 ENEC Proceeding that Companies' witness Jason Stegall's prepared direct testimony in that case had more significantly explained not only the Companies' self-scheduling efforts, but also all of the Companies' strategies for "maximizing" use of the thermal units.[10]

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[9] *Appalachian Power Co.*, Case No. 24-0854-E-42T at 22 (Aug. 28, 2025) ("***Rate Case Order***").

[10] Prepared Direct Testimony of Companies' witness Jason M. Stegall filed on April 30, 2026, in the 2026 ENEC Proceeding ("***Stegall Direct***")

20. Consequently, because it is both helpful and relevant to this proceeding and the formulation of a final version of any rules under HB 2014, attached is a copy of the Stegall Direct as "APCo/WPCo Attachment 3" and the Stegall Rebuttal[11] as "APCo/WPCo Attachment 4" filed in the 2026 ENEC Proceeding, which more fully describe how the coal units are dispatched within PJM, factors that influence dispatch, and strategies the Companies employ to maximize the dispatch of those units on a basis that is affordable to the Companies' customers.

21. As mentioned above, the Companies have an over-arching concern or observation about the Proposed Rules. The Proposed Rules seek the collection of extensive, broad in scope, and very detailed data about electric utilities' generating units; however, it would be best if, first, the Commission were to conduct some workshops at which the Commission, Staff, and CAD can receive presentations by the Companies' personnel skilled in bidding electric utility capacity and energy into PJM on an hourly, daily, and monthly basis, and to ask questions of those personnel to better understand what facts are at issue and the extent of the Companies' control over those facts that form the basis for the Companies' actions in the wholesale electric market managed by PJM. The FirstEnergy companies can also present at such workshops.

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[11] Prepared Rebuttal Testimony of Companies' witness Jason M. Stegall filed on July 15, 2026, in the 2026 ENEC Proceeding ("***Stegall Rebuttal***").

22. Such workshops invite open and thorough discussion of relevant facts and issues in great detail (subject to confidentiality, if necessary), and even allow for exploration of hypotheticals or test approaches to issues – particularly with respect to issues of greatest concern to the Commission.

23. For example, the Companies could make a presentation to the Commission on those issues and take questions to explain the Companies' participation in PJM (including on a FRR basis) and other electric utilities can present on those same topics as it pertains to their participation in PJM's reliability pricing model ("***RPM***").

24. Second, as the Commission is aware, pending before it is Case No. 25-0450-E-GI wherein the Commission has asked the Companies to explain why they should continue to elect FRR status in PJM; how the Companies' capacity is bid into the market; and how such capacity is allocated or assigned among AEP operating companies.[12]

25. The Companies filed a response to the Commission's questions in the FRR Order on October 1, 2025, which also contain information relevant to the purposes behind the Proposed Rules and which response is attached as "APCo/WPCo Attachment 5." And the Companies are currently working on their

[12] *Appalachian Power Co., et al.*, Case No. 25-0450-E-GI (Comm. Ord., May 23, 2025) ("***FRR/RPM Proceeding***" and "***FRR Order***")).

next round of answers to the Commission's questions filed on June 17, 2026 (which answers are due October 30, 2026). *See* Case No. 25-0450-E-GI.

26. At the very least, the Companies recommend that the Commission's Proposed Rules 3.2 (RPM Option) and 3.3 (FRR Option) not be finalized and promulgated until after the conclusion of the FRR/RPM Proceeding, which proceeding might also form a basis for appropriate modifications to those Proposed Rules.

D. The Companies' Gas Units

27. Depending on weather and the demand for electric energy within PJM, the Companies' gas units – like most gas units around the country – are dispatched often by PJM and on an economic basis.

28. Thus, while the Companies completely agree with "maximizing" use of the gas units (subject to the mentioned conditions), as evidenced by the Companies' ENEC proceedings, the Companies submit that the Proposed Rules need not seek the monthly filing of extensive and detailed information pertaining to the gas units. At best, whatever information sought by the Proposed Rules about the gas units is best provided on a more scaled back basis, if at all, in ENEC proceedings along with the voluminous data already provided in those proceedings about the gas units.

E. The Role of and Boundaries Provided by Federal Regulation

29. The Companies cannot – nor can the Commission or the Legislature – minimize federal jurisdiction and the role of PJM over the dispatch of the Companies' thermal units.

30. HB 2014 (*W. Va. Code* § 24-2-1d(f)) contains the requirement that electric utilities maintain their thermal units "to allow them *to be able to*" operate and achieve a 69% capacity factor. Importantly, this is *not* a requirement to operate at 69%; rather, it is a requirement that the units "*be able*" or *be in an operational position* so that they can be dispatched and operate at a 69% capacity factor if economic to do so.

31. The Commission should be aware of this difference, generally, having agreed in a settlement that its past and future orders do not and will not require the Companies' units to operate at a minimum 69% capacity factor.[13]

32. Thus, as the Commission (and perhaps the Legislature) proceeds with the Proposed Rules or any focus on thermal plant dispatch, it is important to be mindful that the regulation of wholesale electricity transactions in interstate commerce and the dispatch of the thermal units in PJM are subject to (often times exclusive and preemptive) federal regulation by the Federal Energy Regulatory Commission pursuant to the Federal Power Act.[14]

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[13] *Bruce Perrone, Rosanna Long, and Sierra Club v. Chairman Charlotte R. Lane et al., and Appalachian Power Co., et al.*, Civil Action No. 2:24-cv-00434 (U.S. Dist. Ct., So. Dist. Of West Virginia). *See* Attachment 6 hereto.

[14] *See* 16 U.S.C. § 824(b)(l). *See e.g., Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373 (2015) (holding that a state law "unmistakably and unambiguously directed at" matters within FERC's jurisdiction is field preempted); *Allco Fin. Ltd. v. Klee,* 861 F.3d 82, 97 (2d Cir. 2017) (explaining that "[c]ompelling a wholesale transaction—one that would not have taken place but for the State's

F. Detailed Comments and Edits to the Proposed Rules

33. The following are the Companies' more detailed comments and edits to the Proposed Rules with the references being to the Proposed Rule numbering. The Companies' specific edits to the Proposed Rules are shown in redline on the attached "APCo/WPCo Attachment 1." In making these detailed comments and edits, the Companies do not waive any of their more general comments above, including but not limited to their overarching comment that the Proposed Rules, in their entirety, should not be adopted, at least not until they are modified after additional stakeholder input is received and fully considered through mechanisms such as workshops.

34. **PR 1.1 and 1.6** reference the "regulation of future electric generating capacity requirements." Neither reference matches the Series 41 title of "Rules Governing Electric Generating Capacity Utilization." Furthermore, the language of these Proposed Rules conflicts with HB 2014, as discussed above in the Companies' general comments. These Proposed Rules and the Series 41 title should instead state "Rules Governing Commission Review of Consumer Economic Dispatch."

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compulsion—plainly involves the regulation of wholesale sales and thus falls squarely within the field that Congress has occupied" in the FPA). FERC's jurisdiction over interstate wholesale rates is exclusive and state regulation that presents a direct and transparent impediment to the functioning of the PJM markets is preempted. *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 475, 480 (4th Cir. 2014). Because the actual dispatch of generating units directly determines which resources clear the federally regulated wholesale market and establish the wholesale market clearing prices, state actions that functionally dictate or alter the parameters of wholesale dispatch and pricing are preempted under the FPA. *See id.* at 472-73.

35. **PR Section 2 (Definitions).** Any proposed definition should match the definitions the Companies adhere to and are used commonly in the electric utility industry. This ensures consistency in reporting and avoids unnecessary confusion.

a. **PR 2.1.** "Capacity factor" should be defined according to the North American Electric Reliability Corporation ("***NERC***") as set forth in the Companies' attached redlines (*see* Attachment 1). NERC only defines two capacity factors: Net Capacity Factor and Gross Capacity Factor. Proposed Rule 2.1, and the sub-definitions found in PR 2.1.1. through 2.1.4., are not recognized as industry standard and are confusing. Moreover, the sub-definitions are not found anywhere in the remainder of the Proposed Rules, so they are also superfluous.

b. **PR 2.8**. The Commission defines "Office of Energy" and elsewhere proposes to share the monthly reports with the Office of Energy (**PR 8.2 and 8.3**). The Order does not explain or set forth a basis for doing so and, furthermore, such rules exceed the scope, purpose, and statutory directives to the Commission in HB 2014 (*W. Va. Code* § 24-2-1d(f)) and call into question the safeguards that are supposed to be in place at the Commission for keeping under seal any confidential information that is filed with it by utilities. There are strict Commission rules

regarding the filing and handling of confidential information that would appear to be abrogated by Proposed Rules 8.2 and 8.3. This definition and related Proposed Rules should be deleted, as reflected in the Companies' redlines.

c. **PR 2.10 - 2.13.** The Companies have proposed edits to the definitions contained in Proposed Rules 2.10 through 2.13, including deleting PR 2.12 in its entirety because it is vague, ambiguous, and confusing. *See* Attachment 1.

36. **PR 3.1**. The Companies propose workshops as initial next steps before "voluntary participation by every electric generating unit subject to the jurisdiction of the Commission in each capacity auction." The Companies do not oppose the concepts of "voluntary" or cooperation with the Commission, and certainly invite the Commission's input to protect customers (again, the benefit of workshops). However, this PR as well as others that suggest significant involvement in the day-to-day process of the Companies' interactions with PJM is unwieldy (if not unlawful[15]).

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[15] "As stated in *Lumberport-Shinnston Gas Co. v. Public Service Commission*, 165 W. Va. 762, 271 S.E.2d 438 (1980), the Public Service Commission is not a super board of directors which oversees the day-to-day operations of the public utilities. Therefore, it would be unreasonable for the Commission to replace the utility's judgement with that of the Commission unless the utility had engaged in a dishonest or clearly inefficient conduct or practice." *Ronal Lilley v. Wheeling Power Co., et al.*, Case No. 09-1154-E-C, Conclusion of Law 2, at 18 (Comm. Ord., Feb 16, 2010). "The Commission is not, however, a super board of directors of the utilities and may not properly engage in managing utility business affairs." *Appalachian Power Co., et al.*, Case No. 07-1731-E-PC et al., at 7 (Comm. Ord., Dec. 21, 2007).

37. **PR 3.2 and 3.3.** The Commission's request for highly sensitive, proprietary, confidential bidding information, *prior to* each capacity auction (at least 28 days), is unworkable[16] and presents significant confidentiality issues. A utility's planned bid should be safeguarded to the fullest extent prior to its submittal, and filing a planned bid with a public agency subject to FOIA threatens the bidding process, especially in light of PR 8.2 and 8.3 discussed above. Furthermore, the Proposed Rules force the utility to lock in a bid four weeks beforehand, which is an unnecessary restriction that limits flexibility and could ultimately harm customers. Lastly, as mentioned above, the same FRR/RPM inquiry is already being conducted in Case No. 25-0450-E-GI, which is a better vehicle for that particular discussion and better reflects the Commission's desire to modify the information gathering process going forward, given the several references to the Commission being able to modify particular rules by order (assuming it even has the ability to unilaterally modify legislative rules).

38. **PR Section 4.** The Proposed Rules need to draw a distinction between PJM's "economic dispatch" model recognized industry-wide and the term "consumer economic dispatch" created by the Legislature in HB 2014; they are not the same thing. Generally, the Companies have edited this Section accordingly in their attached edits. *See* Attachment 1.

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16 *See infra* n.15.

39. **PR 4.2.** As discussed herein, the 10-day timeframe is virtually impossible to achieve, even with added resources (and the additional costs of those resources).

40. **PR 4.3.1.** The terms "significant ramping" and "optimum consumer economic dispatch" are vague and ambiguous, leaving the Companies unable to discern the meaning and scope of the rule. Furthermore, this rule does not ask for the Companies to report existing data, but to create new work product that is highly speculative.

41. **PR 4.3.2.** Nearly all the requested data is already provided to the Commission in ongoing closed-case filings, per several Commission orders in the Companies' ENEC proceedings.

42. **PR 4.3.3.** This data is constantly overwritten during the passage of time and capturing it daily would be a significant undertaking requiring a new program and additional data storage. As an example, if APCo were to capture the availability of Mountaineer for the next seven days, and as of July 31 those days are August 1 to August 7, when the same projection is made on August 1, the data for August 2 through August 7 would be overwritten. Additionally, certain changes in availability would not be captured, such as forced outages and early endings of outages.

43. **PR 4.4.** As mentioned above, this Proposed Rule directly conflicts with HB 2014, as it appears to require (or at least strongly encourage) self-scheduling units over running them according to PJM's economic dispatch model.

The Commission appears to recognize this in labeling the Rule as an "Alternative" to economic dispatch. The record of the Companies' recent ENEC proceedings is clear as to when and why self-scheduling is performed and the costly consequences of blindly running contrary to economic dispatch. Lastly, the Companies would note that, while generation operators can justify to PJM and the Independent Market Monitor why they would self-commit a unit higher than its economic minimum, burning coal for its own sake is not likely to be an acceptable reason and would likely result in the Companies being reported to FERC by the Market Monitor.

44. **PR 5.1.** NERC only identifies Net Capacity Factor and Gross Capacity Factor among its standard indices. For market participation, net generation is the only thing that matters as PJM does not concern itself with parasitic load. Furthermore, the available capacity is already requested in PR 3.2.

45. **PR 5.2.7.** The phrase "excluding overheads" is vague and ambiguous. Whatever overheads are supposed to be excluded from the requested calculation need to be specified in detail so the utility can appropriately respond.

46. **PR 5.3 and 5.3.2.** The Companies have discussed these Proposed Rules at length in their general comments above. Together, these rules can be interpreted to potentially force electric utilities to operate their coal units to achieve a minimum capacity factor regardless of economics, which conflicts with HB 2014 (and may well be pre-empted by PJM and FERC jurisdiction). Furthermore, PR 5.3.2 is vague and ambiguous, particularly in the language regarding the

Commission's "expectations." While the Commission's expectations may be discussed, if at all, in a particular prudence review in a given case, they are not appropriate for Legislative rules that should clearly tell a utility to do or not do something. For all the reasons discussed in these general and specific comments, these Proposed Rules should be stricken entirely.

47. **PR 6.4.** This Proposed Rule is very concerning. Contrary to many years of prudent coal procurement, the Proposed Rule would force the Companies to include "indexed contracts"[17] in their coal supply portfolio, *regardless of the terms*. This is unworkable as the Companies cannot unilaterally command such arrangements with suppliers. As a result, few if any of the Companies' coal suppliers would be willing to supply coal to the Companies under such terms, as the Companies explained in their 2026 ENEC Proceeding. The Companies recently informed the Commission that their particular suppliers are not interested in an indexed contract and explained the basis for their position. *See* 2026 ENEC Proceeding. The rule also is internally inconsistent in its permissive and mandatory phrasing. This rule should be stricken entirely, and the Companies should be permitted to continue to have all tools and options available to them when negotiating coal supply contracts for the benefit of their customers. Last, but far from least and without elaborating in greater detail, there are unintended

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[17] The Companies assume reference is being made to a price based upon or indexed to a PJM LMP price based on the Companies' prior interactions with the Commission on this topic.

consequences that have and may continue to result from LMP-based index pricing that should be a topic of the Companies' proposed workshops.

48. **PR Section 7.** Section 7 of the Proposed Rules appears to be an attempt by the Commission to grant itself the authority to change the rules at any time. This is also a conflict with HB 2014, which expressly states that any rules to carry out its provisions must be made "in accordance with the provisions of §29A-3-1 et seq." PR 7.1.2, in particular, invades the province of the Legislature. These Proposed Rules also reflect a desire by the Commission not to simply review the consumer economic dispatch of generating units, but to control the operation of those units, in violation of *Lumberport-Shinnston Gas Co. v. Public Service Commission*, 165 W. Va. 762, 271 S.E.2d 438 (1980). *See* PR 7.1.1.a. and 7.1.1.b.

Lastly, and as mentioned above, the Companies do not anticipate being able to meet the 10-day deadline and would *on a monthly basis* have to invoke the "Amended Deadlines" provisions of PR 7.2. This would be a tiresome process leading to the filing of the same motion over and over again. For these reasons, Section 7 should be stricken entirely. If at some point it becomes necessary to modify any rules that end up being approved by the Legislature, then such modifications should rightfully go through the same process as the instant rules. The Proposed Rules have the potential to affect not just electric utilities, but all of their West Virginia customers – they should not be modified except pursuant to existing law and legislative process.

49. **PR Section 8.** PR 8.2 and 8.3 should be stricken entirely, as discussed above.

G. West Virginia Administrative Procedures Act

50. The authorizing legislation, HB 2014, expressly provides that the Proposed Rules are subject to "legislative approval in accordance with the provisions of §29A-3-1 *et seq.*" of the West Virginia Code, that is, the West Virginia Administrative Procedures Act ("***WV APA***").

51. *W. Va. Code* § 29A-3-5 requires that, "[a]t the time of filing the notice of its action, the agency shall also file with the Secretary of State a copy of the full text of the rule proposed and a fiscal note as defined in subsection (b), section four of this article." The Commission's filed notice, attached hereto as "APCo/WPCo Attachment 7," fails to comply with this statute because it does not include the required fiscal note. That fiscal note must "itemiz[e] the cost of implementing the rules as they relate to this state and to persons affected by the rules. The fiscal note shall include all information included in a fiscal note for either house of the Legislature and a statement of the economic impact of the rule on the state or its residents. The objectives of the rule shall be clearly and separately stated in the fiscal note by the agency issuing the proposed rules." *W. Va. Code* § 29A-3-4. The Commission simply wrote "N/A" in many parts of the filed notice. *See* Attachment 7.

52. The Commission failed to afford interested persons a full 30 days to file initial comments, in violation of *W. Va. Code* § 29A-3-7. Additionally, in this

regard, the separating of comments into "initial" and "reply" forms is very likely confusing to the public. Several things are unclear, especially to persons not familiar with Commission processes: Can a person file only one set of comments by the reply deadline? To what comments may a person reply? Must a person file initial comments in order to file reply comments? Given the potential impact of the Proposed Rules on the public, a clearly communicated and sufficient amount of time for comments under the WV APA should have been given.

53. Lastly, the Companies reserve the right to assert any challenge to the Proposed Rules under the WV APA, whether included in these initial comments or not.

CONCLUSION

WHEREFORE, the Companies respectfully request that the Commission not finalize or approve the Proposed Rules as written at this juncture and, instead, implement the Companies' recommendations herein.

Respectfully submitted,

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
By Counsel

/s/Keith D. Fisher
Keith D. Fisher, Esq. (WVSB 11346)
Senior Counsel
200 Association Dr. Suite 201
Charleston, WV 25311
kdfisher@aep.com

/s/Kurt L. Krieger
Kurt L. Krieger, Esq. (WVSB 4927)
Kurt.krieger@steptoe-johnson.com
Todd M. Swanson, Esq. (WVSB 10509)
Todd.swanson@steptoe-johnson.com
STEPTOE & JOHNSON PLLC
Chase Tower, 17th Floor
P. O. Box 1588
Charleston, WV 25326-1588
(304) 353-8124

Dated: August 10, 2026

ATTACHMENT 1

TITLE 150
LEGISLATIVE RULE
PUBLIC SERVICE COMMISSION

SERIES 41
RULES GOVERNING ~~ELECTRIC GENERATING CAPACITY UTILIZATION~~COMMISSION REVIEW OF CONSUMER ECONOMIC DISPATCH

§150-41-1. General

1.1. Scope. -- The following rules govern the ~~regulation of electric generating capacity requirements~~review of consumer economic dispatch by electric utilities subject to the jurisdiction of the Public Service Commission pursuant to W. Va. Code §24-2-1d.

1.2 Authority. -- W. Va. Code §24-2-1d.

1.3. Filing Date. -- [ ] 2026.

1.4. Effective Date. -- [ ].

1.5. Sunset Date. – This rule shall terminate and have no further force and effect on August 1, 2031.

1.6. Intent. -- This Rule is promulgated pursuant to the mandate contained in W. Va. Code §24-2-1d(f), which required the Commission to ~~issue rules regarding the regulation of future electric generating capacity requirements~~review the consumer economic dispatch by electric utilities subject to its jurisdiction.

1.7. The contact information for the Commission is:

Public Service Commission of West Virginia
201 Brooks St.
P.O. Box 812
Charleston, WV 25323
Main switchboard telephone 304-340-0300
Main telefax 304-340-0325
Web site: www.psc.state.wv.us

§150-41-2. Definitions.

The definitions set forth in W. Va. Code §24-1-2, and the definitions for "projected deficient capacity" and "consumer economic dispatch," set forth in W. Va. Code §24-2-1d, shall apply to this rule, and have the same meanings when used herein, unless the context clearly indicates otherwise. For purposes of this rule, the following additional terms have the meanings as described below:

2.1. ~~"Capacity factor" means the ratio of the actual energy produced by a power plant or unit within a power plant over a specific period to the maximum possible energy it could have produced if running at full capacity during that same period. Capacity factors can be calculated based on various measures of maximum possible energy production, including, but not limited to:~~

2.1.1. ~~"Gross installed capacity factor" means the ratio of the gross energy produced by a power plant or unit to the maximum possible energy it could have produced if running at full installed capacity during the same period.~~

2.1.2. ~~"Net installed capacity factor" means the ratio of the net energy delivered to the grid after deducting parasitic load to the maximum energy that could have been delivered to the grid after deducting parasitic load if running at full installed capacity during the same period.~~

2.1.3. "Gross ~~available~~ capacity factor" ~~means the ratio of the gross energy produced by a power plant or unit to the maximum possible energy it could have produced if running at full available capacity during the same period~~is defined and calculated in accordance with the Gross Capacity Factor formula defined by the North American Electric Reliability Corporation (NERC).

2.1.4. "Net ~~available~~ capacity factor" ~~means the ratio of the net energy delivered to the grid after deducting parasitic load to the maximum possible energy that could have been delivered to the grid after deducting parasitic load if running at the available capacity during that same period~~is defined and calculated in accordance with the Net Capacity Factor formula defined by NERC.

2.2. "Capacity Resources" means a resource that can provide electricity or reduce the demand for electricity and includes megawatts of net capacity from existing or planned Generation Resources or load reduction capability provided by demand resources.

2.3. "Effective Load Carrying Capability" (ELCC) is the capacity value fractional multiplier applied by PJM to various resources' maximum rated capacity to define their expected output during periods of maximum stress on the system. ELCC values are revised annually by PJM.

2.4. "Fixed Resource Requirement" (FRR) is an alternative option for Load Serving Entities (LSEs) to self-supply resources rather than participate in the PJM RPM auction process.

2.5. "Generation Resource" means any generating unit that meets the qualification requirements to participate in the PJM capacity market or energy market.

2.6. "Installed Capacity" (ICAP) is the summer capacity rating for capacity resources before adjustments for expected forced outages.

2.7. "Locational Marginal Price" (~~LPM~~LMP) is the pricing mechanism used in the PJM wholesale electricity market and represents the hourly integrated marginal market clearing price for electrical energy at the location where the energy is delivered into PJM or received to serve load.

2.8. ~~"Office of Energy" means the West Virginia Office of Energy established in W.Va. Code §5B-2F-2.~~

2.9. "PJM" stands for the PJM Interconnection LLC, the regional transmission organization responsible for coordinating, controlling, and transmitting electricity throughout its authorized footprint.

2.10. "Reliability Pricing Model" (RPM) is PJM's resource adequacy construct designed to acquire capacity resources to meet net capacity requirements on the PJM system through a series of capacity auctions for each PJM Delivery Year, which runs from June 1 through May 31.

2.11. "Self-schedule" as applied to electrical energy in PJM refers to the commitment of a generating unit with a status of Must-Run, which results in the unit being committed at its economic minimum level of output. A unit that is self-scheduled will, barring outage, produce its economic minimum level of output in each hour covered by PJM's Day Ahead settlement process~~means the daily scheduling and control of a Generation Resource by the owner or operator of the facility that is not dependent on economic dispatch control by PJM~~.

2.12. ~~"Self-schedule" as applied to electrical capacity means resources specified price takers by a resource provider in the PJM Capacity Auctions to guarantee that the resource will clear in the auction. If a resource is designated as Self-scheduled by the resource provider, the Self-Scheduled resources is cleared first in the auction before clearing any market bids.~~

2.13. "Unforced Capacity" (UCAP) is the MW value of ~~a capacity resource that is available to meet demand, adjusted for the resource's expected forced outage rate~~accredited capacity that an individual generating unit provides to PJM.

§150-41-3. Participation in PJM Capacity Auctions.

3.1. Capacity Auctions. -- The Commission encourages voluntary participation by every electric generating unit subject to the jurisdiction of the Commission in each capacity auction.

3.2. RPM Option. -- To enable the Commission to monitor and evaluate the participation in the capacity market each electric utility subject to jurisdiction of the Commission that owns or is contractually entitled to a capacity resource and is operating under the RPM option in PJM, shall report to the Commission its proposed capacity offers for the next upcoming RPM capacity auction.

3.2.1. The utility report shall include the following:

3.2.1.a. A listing of its owned or under contract capacity resources,

3.2.1.b. The ICAP and UCAP of each resource,

3.2.1.c. The PJM assigned ELCC of each resource,

3.2.1.d. Identification of units that are eligible to bid into the capacity auction,

3.2.1.e. The UCAP quantity of each eligible resource proposed to be bid into the market,

3.2.1.f. The price proposed for each bid, which may be zero for self-scheduled capacity, and

3.2.1.g. Other information which the Commission determines is necessary to allow the Commission to meet the objectives of this subsection.

3.2.2. This report shall be submitted to the Commission at least 28 calendar days prior to submitting the capacity bid. The Commission may modify the filing deadline by a general or specific order.

3.2.3. The utility participating in this model shall also file a verified statement or testimony explaining why it chooses to forego the FRR option and the benefits to West Virginia ratepayers of remaining in the RPM. The benefits should be quantified with comparisons of the costs to ratepayers of RPM participation versus the costs of FRR participation using the RPM capacity to meet its FRR obligation. The comparisons should cover the last three PJM delivery years. The statement or testimony shall provide information on the timing and steps necessary to switch to FRR and any jurisdictional issues that would complicate such switching if required by the Commission.

3.2.4. The utility shall simultaneously file a public version and a confidential version of the quantity and price information contained in its report, which shall comply with the Commission directives for limiting and marking redacted information. The confidential version of the quantity and price information shall be deemed to be a confidential trade secret, as recognized in W.Va. Code §29B-1-4, and shall not be available to any entity seeking access to the information, unless access under a Confidentiality Agreement is required by order of the Commission.

3.3. FRR Option. -- To enable the Commission to monitor and evaluate the participation of the utility in the capacity market each electric utility subject to the jurisdiction of the Commission that owns or is contractually entitled to a capacity resource and is operating under the FRR option in PJM shall report to the Commission its current capacity requirement as assigned by PJM, and the resources that it owns or has under contract that qualify to satisfy its PJM FRR capacity obligation.

3.3.1. The information filed shall include the following:

3.3.1.a. A description of the timing for the development of the capacity obligation by PJM,

3.3.1.b. The current ICAP and UCAP of each FRR resource,

3.3.1.c. The PJM assigned ELCC of each capacity resource, and

3.3.1.d. Other information which the Commission determines is necessary to allow the Commission to meet the objectives of this subsection.

3.3.2. This report shall be submitted to the Commission at least 28 calendar days prior to submitting the capacity bid. The Commission may modify the filing deadline by a general or specific order.

3.3.3. The FRR utility shall file a verified statement or testimony explaining why it chooses to forego the RPM and the corollary benefits to West Virginia ratepayers. The benefits should be quantified with comparisons of the costs to ratepayers of FRR capacity versus the costs of RPM participation using the FRR capacity within the RPM. The comparisons should cover the last three PJM delivery years. The statement or testimony shall also provide information on the timing and steps necessary to switch to the RPM and any jurisdictional issues that would complicate such switching if required by the Commission.

§150-41-4. Consumer Economic Dispatch.

4.1. Consumer Economic Dispatch. -- In accordance with W. Va. Code §24-2-1d(e) the commission shall review each generating unit's ~~consumer~~ economic dispatch to determine if each unit is operated to produce electricity at its lowest cost consistent with consumer demand, and operational limits of the generation facility and transmission facilities as determined by PJM. To determine if the utility is operating each generating unit at its lowest cost, the Commission will review the cost of producing electricity per kilowatt hour of output at each generating unit at varying capacity utilization levels. Each electric utility subject to the jurisdiction of the Commission must plan the operation of each generating unit under its control to produce electricity at the lowest achievable cost per kilowatt hour. The Commission will review ~~consumer~~ economic dispatch results on a daily, weekly, monthly, and annual basis.

4.2. Generation Dispatch Reports. -- Each electric utility subject to this rule that owns or controls energy resources shall file a Generation Dispatch Report, which shall include monthly information regarding the hourly dispatch of each of its generation units into the PJM day-ahead and real-time energy markets for the month prior to the filing month. The Generation Dispatch Report is due on the tenth business day of each month, and shall include information for the month immediately preceding the filing month.

4.3. Information on ~~Consumer~~ Economic Dispatch. -- Each Generation Dispatch Report filed pursuant to this rule shall provide the cost of generation at various output levels. If plants are run at less than the lowest cost output levels the utility shall quantify the impact on ~~consumer~~ economic dispatch from running plants at less than their optimum economic capability. If running generation units at higher output levels than those achieved during any reporting period would have resulted in lower cost per kilowatt hour of output, the utility must explain why it did not maximize ~~consumer~~ economic dispatch of the generating units.

4.3.1. The utility should report the actual or estimated impact on maintenance costs and

future equipment replacement attributable to significant ramping of unit output throughout each 24-hour period. If ramping output resulted in generating at less than optimum ~~consumer~~ economic dispatch was a trade-off between optimum consumer economic dispatch of generation units and lower cost market purchases, then the utility must quantify benefits of market purchases as compared to the total cost of generation, after considering the actual or estimated impact on maintenance costs and future equipment replacement attributable to ramping of unit output.

4.3.2. In a working and editable spreadsheet with the formulas intact, the report shall show for each hour of each day the following information:

4.3.2.a. The hourly installed ~~gross and~~ net capacity available to be bid or self-scheduled into the day-ahead market,

4. 3.2.b. The hourly volume of net capacity bid into the market and the related cost-based and market-based bid amounts as dollars per megawatt hour,

4. 3.2.c. The hourly net capacity that cleared the day-ahead market,

4. 3.2.d. The hourly self-scheduled capacity delivered into the day-ahead market, and

4.3.2.e. The hourly PJM LMP at the pricing nodes for each capacity resource, including the PJM identification number for each node. The report shall also show energy delivered into the PJM real-time energy market.

4.3.3. Each Generation Dispatch Report shall provide the schedules of availability for seven days in advance provided to PJM during the report month as required by PJM Manual 11 as follows: "Generation Capacity Resources that have an RPM or FRR commitment shall submit a schedule of availability for the next seven (7) days and may submit non-binding offer prices for the days beyond the next Operating Day." (*See* PJM Manual 11 at page 27, https://www.pjm.com/-/media/DotCom/documents/manuals/m11.pdf, effective October 1, 2025.)

4.3.4. The Generation Dispatch Report shall also indicate multiple-day volumes and offer prices if energy market offers or Self-scheduled volumes were submitted for days beyond the next Operating Day.

4.4. Alternative. -- If a utility subject to this rule has chosen not to self-schedule all or any of its generation capacity during any day or portions of a day it shall explain why it made that decision. This explanation must be included in its monthly Generation Dispatch Report.

§150-41-5. Capacity Factors.

5.1. Information on Capacity Factors. -- Each electric utility subject to the rate jurisdiction of the Commission that operates generation facilities shall report in its Generation Dispatch Report the capacity factors achieved at each generating unit relative to the following:

5.1.1. Maximum nameplate generation capacity of each unit,

5.1.2. Net maximum generation capacity of each unit after plant parasitic load,

5.1.3. Available nameplate generation capacity of each generating unit,

5.1.4. Available net maximum generation capacity of each unit after plant parasitic load; and

5.1.5 The underlying values supporting the calculated capacity factors.

5.2. Verified Statement. -- Each electric utility shall include in its Generation Dispatch Report a verified statement which may be in standard narrative format or in question and answer format explaining the causes and reasons that the net capacity after parasitic plant use was not one hundred percent of installed capacity net of typical plant use. The report shall include:

5.2.1. Reasons for outages;

5.2.2. Duration of outages;

5.2.3. Remedial action scheduled to remedy outages;

5.2.4. Time when the outage first occurred;

5.2.5. Time when the outage was remediated;

5.2.6. Total elapsed hours of each outage; and,

5.2.7. Direct incremental cost of each remediation, excluding overheads. Direct incremental costs are those costs that would not have been incurred but for the remediation.

5.3. Capacity Factor. -- The Commission expects generating electric utilities subject to the rate jurisdiction of the Commission to maintain their generation plants and schedule maintenance to minimize down time to allow it to achieve a minimum capacity factor of sixty-nine (69%) percent. The success in achieving a minimum capacity factor will initially be measured over a twelve-month period.

5.3.1. The utilities will include in their monthly Generation Dispatch Reports their actual capacity factors in tabular format for the report month and a rolling average up to December. Beginning with January of each year the rolling average reported shall restart. All prior month's data shall continue to be reported even though the rolling average is restarted.

5.3.2. The utilities are expected to take advantage of PJM Manual 11 Market Rules 2.3.3., *et seq.,* which allow self-scheduling rather than allowing PJM to accept or reject their output into the day-ahead market. The utility is not expected to operate at a net-positive margin in all hours of the day. It is expected to reasonably anticipate and project expected day-ahead market prices

and schedule increments of generation to minimize negative margins during periods of low market prices while allowing for reasonable, and limited ramping of generation levels as market prices fluctuate in the day-ahead market.

§150-41-6. Management of fuel supplies and contracts.

6.1. Information on Fuel. -- At the time of filing of the Generation Dispatch Report, the electric utility shall file a PDF file properly formatted for printing as an 8 ½ x 11 inch document or a printed document along with a spreadsheet relating to the fuel supplies for the utility.

6.1.1. The Generation Dispatch Report shall include the following information:

6.1.1.a. The average cost and the volumes of coal in inventory at the beginning of the report month at each coal stockpile location;

6.1.1.b. The volumes and cost of coal delivered into the stockpile(s) during the month;

6.1.1.c. The volumes burned each month;

6.1.1.d. Any stockpile adjustments made during the month; and

6.1.1.e. The average cost and the volumes of coal in inventory at the end of the month.

6.1.2. The volumes and costs of coal in inventory shall be reported on both a tonnage basis and million British thermal unit ("MMBTu") basis.

6.1.3. The report shall also show the detailed total dollars and weighed average cost of coal per ton for each of the four volume categories listed above, divided between F.O.B. mine, transportation, and handling costs, both transportation and in-plant related, if applicable.

6.2. Summary Price Adjustments. -- The utility shall include a summary of price adjustments at each coal stockpile location applicable to prior months that were not known at the time reports for those months were made.

6.2.1. If there was a stockpile adjustment for any report month, the utility shall file a copy of the stockpile report and the derivation of the adjustment in tons and dollars.

6.2.2. If any stockpile adjustment exceeds five percent of the tonnage or dollar value of the inventory, the electric utility shall file a verified statement or testimony explaining the reasons that the stockpile had been misreported in the past.

6.3. Solicited Bids for Coal. -- For each monthly Generated Dispatch Report, the utility shall report the expected date for its next solicitation of bids for coal. It shall also report on the results and details of any bids received and contracts consummated prior to the report month.

6.4. Coal Contracting. -- When eliciting requests for coal contracting proposals, each electric utility subject to these rules shall make it clear that contracts indexed to the price of PJM day-ahead LMP will be considered. It shall indicate that alternative indexing that is expected to follow electricity wholesale prices in PJM may also be offered and will be considered by the utility. It shall make it clear that proposals may contain only an indexed contract or a mix of fixed-price and indexed contracts. The utility shall endeavor to maintain a mix of short-term and long-term contracts that also contain a mix of fixed-price and indexed contracts.

§150-41-7. Additional information.

7.1. Additional Information. -- The information required by this rule is not exhaustive of all information that the electric utility must provide.

7.1.1. The Commission may require additional or differently formatted information if the Commission determines that the additional information is necessary:

7.1.1.a. To ensure that the utility is maximizing the production of electricity from their generating units,

7.1.1.b. To ensure that the utility is acting to reduce energy costs for West Virginia ratepayers, or

7.1.1.c. To clarify, explain, justify, or further explain any information required by the code or this rule to be provided to the Commission.

7.1.2. A modification may be achieved by general order, specific order applicable to a single utility, or as a request from the Commission or designated staff.

7.1.3. It shall be the responsibility of the utility to provide timely additional requested information.

7.2. Amended Deadlines. – If a utility is unable to meet a deadline required by this rule, and such failure is because it has not or cannot receive the PJM in time, or for any reason outside the control of the utility, then the utility may request the Commission to modify the deadline. The Commission may grant the requested modification, for good cause shown, and shall set a new deadline. The Commission may employ a standard extension timeframe for utilities, when the cause for the deadline extension is a failure to timely receive PJM information.

§150-41-8. Confidentiality

8.1. In addition to section 3.2.4 of this rule, ~~but subject to the other provisions of this section,~~ all confidential business information, including trade secrets or other proprietary data or processes, shall be exempt from disclosure pursuant to W. Va. Code §§29B-1-1 *et seq*.

8.2. ~~The Commission shall forward, share, or otherwise make available to the Director of the Office of Energy all unredacted reports and records provided to the Commission pursuant to~~

~~this rule. The Office of Energy shall be bound by the same confidentiality restrictions as the Commission, and may not publicly disclose confidential business information.~~

8.3. ~~Nothing contained herein precludes either the Commission or the Office of Energy from relying upon confidential business information or other protected information to address challenges with, and make improvements to, the state of energy in West Virginia. Protected information may be used to develop an energy plan, manage affordability, increase availability, rectify vulnerabilities, or take any other action consistent with the statutory directives of either the Commission or the Office of Energy. Any data compilation, plan, report, or other document which is made publicly available shall not include confidential business information which can be readily associated with the source utility. Such restrictions does not extend to information which is not determined to be confidential, and which is not otherwise protected by law.~~

ATTACHMENT 2

Keith D. Fisher
Senior Counsel

200 Association Drive, Suite 201
Charleston, WV 25311
304.348.4154
kdfisher@aep.com

APPALACHIAN POWER
An AEP Company
BOUNDLESS ENERGY

July 15, 2026

Via Electronic Filing
Karen Buckley, Executive Secretary
Public Service Commission of West Virginia
201 Brooks St.
Charleston, WV 25301

Re: Case Nos. 25-0859-E-IRP and 25-0860-E-IRP
Integrated Resource Plans of Appalachian Power Company and Wheeling Power Company

Dear Ms. Buckley:

I enclose herewith for filing, in the above-referenced matters, a "**Joint Stipulation and Agreement for Settlement**" signed by all parties to these matters except the Consumer Advocate Division.

Thank you for your attention to this matter.

Sincerely,

Keith D. Fisher (WV State Bar #11346)
Counsel for Appalachian Power Company and Wheeling Power Company

Enclosure
cc: Certificate of Service

**PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON**

CASE NOS. 25-0859-E-IRP and 25-0860-E-IRP

**APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY,**
public utilities.

*Integrated Resource Plans of
Appalachian Power Company and
Wheeling Power Company*

JOINT STIPULATION AND AGREEMENT FOR SETTLEMENT

Pursuant to *W. Va. Code* § 24-1-9(h) and Rule 13.4 of Title 150, Series 1, of the Public Service Commission of West Virginia's *Rules of Practice and Procedure*, the following parties to this proceeding (hereinafter the "Stipulating Parties"), Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo") (collectively the "Companies"), the Staff of the Public Service Commission of West Virginia (the "Staff"), the West Virginia Energy Users Group ("WVEUG"), the West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia ("CAG/SUN/EEWV"), and the West Virginia Coal Association ("WVCA"), join in this Joint Stipulation and Agreement for Settlement ("Agreement"), and request that the Public Service Commission of West Virginia (the "Commission") approve and adopt the Agreement, in its entirety and without modification.[1] If adopted, the Agreement would enable the above-referenced proceeding to be resolved efficiently.

[1] The only other party to these matters, the Consumer Advocate Division ("CAD"), declined to join in this Stipulation.

In support of the Agreement, the Stipulating Parties make the following representations:

PROCEDURAL HISTORY

1. On October 1, 2025, the Companies filed their Integrated Resource Plans ("IRPs") pursuant to W. Va. Code § 24-2-19 and Commission General Order No. 183.15.

2. Subsequent to the filing of the IRPs, the CAD, WVEUG, CAG/SUN/EEWV, and WVCA each filed a petition to intervene and was granted intervention in this case.

3. On November 26, 2025, the Commission entered an Order in this proceeding which, among other things, established dates for the filing of testimony and scheduled an evidentiary hearing in this matter.

4. On January 7, 2026, the Companies submitted the direct testimony of Company witnesses Randall R. Short and Mohamed M. Abukaram.

5. On March 16, 2026, the following testimony was filed in this matter by the following parties:

   a. Staff – Direct Testimony of Terry R. Eads

   b. CAG/SUN/EEWV – Direct Testimony of Chelsea Hotaling and Catherine M. Kunkel

6. On April 22, 2026, the Companies submitted the rebuttal testimony of Company witnesses Randall R. Short, Mohamed M. Abukaram, and Troy L. Bumgarner.

7. Subsequent to the filing of rebuttal testimony, the parties conferred to discuss the possibility of reaching settlement on the issues in this proceeding.

8. Following several discussions and settlement exchanges, the Stipulating Parties agreed to the terms set forth below and submitted the instant Agreement to the Commission.

SUBSTANTIVE TERMS

9. The Stipulating Parties propose to the Commission the elements set out below as a fair and just resolution of all the contested issues in this proceeding.

10. In addition to agreeing that the Companies' IRPs filed on October 1, 2025, should be accepted and approved by the Commission as filed, the Stipulating Parties agree as follows:

a. Prior to procuring capacity from any third party to meet a short-term capacity deficiency, Wheeling Power Company shall first evaluate whether sufficient capacity is available from Appalachian Power Company and, if so, shall seek to source that capacity from APCo.

b. The Companies and Commission Staff shall convene stakeholder meetings to identify measures to increase customer participation in APCo's Tariff RSD. For purposes of this provision, "stakeholders" shall mean all parties granted intervention in Case Nos. 25-0859-E-IRP and 25-0860-E-IRP.

c. In their next IRP anticipated to be filed in 2030, the Companies shall include indirect and allocated costs when presenting cost information for any thermal generating unit.

d. In their next IRP, the Companies shall include at least one environmental performance indicator in their Portfolio Performance Indicator Matrix. Any

such indicator shall be defined and calculated consistently and presented in a manner that permits comparison across resource portfolios.

e. Sensitivities:

   i. In their next IRP, if the Companies impose build limits on resources in their capacity expansion modeling, the Companies will also perform a sensitivity that omits those build limits.

   ii. In their next IRP, if the Companies use a capacity contingency, such as the 5% contingency used in the 2025 IRP, the Companies will also present a sensitivity without the contingency.

   iii. In their next IRP, if the Companies apply a degradation factor to energy efficiency savings in their capacity expansion modeling, the Companies shall (a) model each EE measure bundle using its full expected average measure life as reflected in the underlying source data, without truncation to a shorter degradation curve; and (b) perform and present a full portfolio optimization in which no degradation factor is applied, along with a comparative discussion of how EE resource selection and total resource costs differ between the two runs.

f. In the event of material changes to PJM capacity market rules, applicable environmental regulations, or the Companies' load forecast prior to the Companies' next scheduled IRP filing (anticipated to be filed in 2030), the Companies shall update their planning and cost assumptions and capacity expansion modeling in that IRP filing to reflect such changes.

g. Until the submission of the Companies' next IRP (anticipated to be filed in 2030), the Companies will file an updated load forecast each year, beginning on June 30, 2027, as a closed-case filing in this docket. The filing shall include a narrative description that identifies any significant changes since the previous load forecast was filed. Additionally, if a new load greater than 250 MW is added to the Companies' load forecast within six months of the previous closed-case filing, the Companies will file an updated load forecast within 90 days of the load addition.

h. In light of the Companies' inflation-based base rate adjustment which takes effect on July 1, 2026, the Companies do not intend to file a base rate case any sooner than June 1, 2027. In their next base rate case, the Companies will include a list of major repairs and upgrades made to each generating plant, including the capital expended for each.[2] In the event the Companies do not file a base rate case in a given calendar year subsequent to the approval of this Joint Stipulation, the Companies agree to prepare and file a list of major repairs and upgrades made to each generating plant in the previous twelve (12) months, and a list of major repairs and upgrades the Companies intend to make in the ensuing twelve (12) months, with a schedule for completion of each upgrade or repair, by June 30 of each year, and provide that list and schedule to the Stipulating Parties and Commission as a closed case filing in this matter. The obligations set forth in this

[2] For purposes of this provision, "major repairs and upgrades" shall include any project whose cost is $1 million or greater.

paragraph shall continue until, and be re-examined in, the Companies' next IRP filing expected to be made in the year 2030. In addition, within thirty (30) days of the execution and entry of this Joint Stipulation, the Companies will file a list of major plant upgrades and repairs they intend to complete at each generating plant on or before June 30, 2027, with a schedule for completion of each upgrade or repair. In their next base rate case and their closed case filings, the Companies shall also provide the following information for each generating plant: (a) total capital expenditures and total O&M expenses incurred during the previous twelve (12) months, and (b) the Companies' projection of total capital expenditures and total O&M expenses for the ensuing twelve (12) months.[3]

i. With respect to other issues raised in the Companies' IRP or the parties' testimony, all parties shall be free to take whatever position they wish in a future Commission proceeding. Nothing herein will be construed as a waiver of any party's rights to take any position in a future Commission proceeding.

GENERAL PROVISIONS

11. The substantive terms of this Agreement reflect compromises by the Stipulating Parties of their original positions and constitute a fair and reasonable resolution of all the contested issues in this proceeding, taking into consideration the

[3] If any portion of the closed-case filings contemplated by this Paragraph 10(h) contain confidential information, the Companies shall file both public (redacted) and confidential (unredacted) versions in accordance with Commission law and shall provide the confidential (unredacted) version only to those parties who have executed a protective agreement.

interests of the Companies and their customers, the other Stipulating Parties, and the public interest of West Virginia.

12. This Agreement is entered into subject to the acceptance and approval of the Commission. It results from a review of any and all filings in this proceeding, the Stipulating Parties' testimony and exhibits, and thorough discovery and discussion. It is being proposed to expedite and simplify the resolution of this proceeding. It is made without any admission or prejudice to any positions which any party might adopt during subsequent litigation. The Stipulating Parties adopt this Agreement as being in the public interest, without adopting any of the positions set forth herein as ratemaking principles applicable to future proceedings, except as expressly provided herein. The Stipulating Parties acknowledge that it is the Commission's prerogative to accept, reject, or modify any stipulation; however, in the event that this Agreement is rejected or modified by the Commission, it is expressly understood by the Stipulating Parties that they are not bound to accept this Agreement as modified, and the Stipulating Parties may avail themselves of whatever rights are available to them under law and the Commission's *Rules of Practice and Procedure*.

WHEREFORE, the Stipulating Parties respectfully request that the Commission make appropriate Findings of Fact and Conclusions of Law adopting and approving, *in toto* and without modification, all of the elements of the negotiated settlement arrived at by the Stipulating Parties as set forth in this Agreement.

Respectfully submitted this 15th day of July, 2026.

APPALACHIAN POWER COMPANY and WHEELING POWER COMPANY

By: Keith D. Fisher

Name: Keith D. Fisher

Their: Senior Counsel

STAFF OF THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

By: Victoria Wilson by KDF w/ permission

Name: Victoria Wilson

Its: Staff Attorney

WEST VIRGINIA CITIZEN ACTION GROUP, SOLAR UNITED NEIGHBORS, and ENERGY EFFICIENT WEST VIRGINIA

By: Emmett Pepper by KDF w/ permission

Name: Emmett Pepper

Its: Legal Counsel

WEST VIRGINIA ENERGY USERS GROUP

By: Barry Naum by KDF w/ permission

Name: Barry Naum

Its: Legal Counsel

WEST VIRGINIA COAL ASSOCIATION

By: Jacob Altmeyer

Name: Jacob Altmeyer

Its: Legal Counsel

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NOS. 25-0859-E-IRP and 25-0860-E-IRP

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY,
public utilities.

Integrated Resource Plans of
Appalachian Power Company and
Wheeling Power Company

CERTIFICATE OF SERVICE

I, Keith D. Fisher, counsel for Appalachian Power Company and Wheeling Power Company, do hereby certify that a true and correct copy of the foregoing filing was served electronically upon counsel of record in the above-referenced matters on this 15th day of July, 2026.

Keith D. Fisher (WV State Bar #11346)

ATTACHMENT 3

DIRECT TESTIMONY OF JASON M. STEGALL

DIRECT TESTIMONY OF
JASON M. STEGALL
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 26-_____-E-ENEC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jason M. Stegall. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by American Electric Power Service Corporation ("AEPSC") as Director of Regulatory Services. AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power ("AEP") system, which include Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo") (together, the "Companies").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the Virginia Polytechnic Institute and State University with a Bachelor of Science degree in Accounting, in 1997. I earned my Master's in Business Administration from the Ohio State University in 2011. In addition, I attended the 2018 EEI Transmission and Wholesale Markets School.

I joined AEPSC in June 1997 as an Accountant in the Regulated Accounting Division of the Accounting Department. From 1997 to 2009, I held various positions in Accounting and Risk Management. In July 2009, I joined the Regulatory Services Department as a Regulatory Consultant in Customer and Distribution Services Support. In July 2010, I transferred to Regulated Pricing & Analysis where my role focused on developing cost-of-service studies and rate designs as well as other projects related to regulatory issues and proceedings, individual customer requests, and general rate matters. In December 2017, I was promoted to Manager of Regulatory Pricing where I managed the team that supports the fuel-related and purchased power-related filings across AEP's eleven retail jurisdictions. In September 2022, I was promoted into my current position where, in addition to my previous duties, my team also provides analysis and support for owned and contracted generation resources in all of AEP's retail jurisdictions.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am providing testimony on behalf of the Companies.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring APCo/WPCo JMS-D Attachment 1, which provides plant level financial and operational information for the Companies' coal-fired plants.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony and appeared before this Commission on behalf of the Companies in Case Nos. 21-0339-E-ENEC, 22-0393-E-ENEC, 23-0377-E-ENEC, 24-0413-E-ENEC, and 25-0413-E-ENEC. In addition, I have filed testimony and appeared on behalf of APCo before the Virginia State Corporation Commission. I have also filed testimony on behalf of other AEP operating companies in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, and Texas and have appeared before the commissions in Arkansas, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, and Texas.

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

A. The purpose of my testimony is to:

- Respond to certain aspects of the Commission's August 28, 2025, order in Case No. 25-0854-E-42T;

- Discuss the PJM energy market conditions during the "Review Period," the 12-month period March 1, 2025, through February 28, 2026;
- Describe the Companies' participation in the PJM market;
- Explain PJM's role in determining the level of a generation unit's output;
- Describe the Companies' response to PJM market conditions; and
- Address the capacity factors for the Companies' fossil fuel generating units and their performance relative to the PJM wide fleet.

Q. WHAT CONCLUSIONS SHOULD THE COMMISSION DRAW FROM YOUR TESTIMONY?

A. The Commission should draw the following conclusions from my testimony:

1. The Companies' PJM energy market strategy for their generating units is consistent, prudent, and reasonable, as are all of the many analyses and actions that I will describe, which must often occur on a real-time basis in support of that strategy. During the Review Period, the Companies' coal-fired generating units produced $339.5 million of revenues in excess of fuel, fuel handling, and environmental costs.
2. The Companies, through their market offer strategy and the use of a Must-Run commitment status, as discussed in my testimony, effectively offered their units into the PJM energy markets in a way that provided value to customers.

3. The Companies' market offer strategy resulted in net capacity factors at its coal-fired units that are in line with coal-fired units in PJM.

ORDER IN CASE NO. 24-0854-E-42T

Q. PLEASE PROVIDE THE LANGUAGE IN THE COMMISSION'S AUGUST 28, 2025, ORDER TO WHICH YOU ARE RESPONDING.

A. On page 22 of its Order, the Commission stated:

> If we misunderstand the flexibility for FRR [Fixed Resource Requirement] 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,.... 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.

Q. PLEASE DESCRIBE PJM'S FIXED RESOURCE REQUIREMENT.

A. PJM's Fixed Resource Requirement ("FRR") option is a means by which a Load Serving Entity ("LSE") can self-supply its capacity obligation in PJM. PJM requires every LSE in its footprint to obtain sufficient capacity to serve its peak demand while also maintaining an adequate level of reserve. LSEs

have the choice to purchase capacity through PJM's capacity auctions or supply their own capacity from resources they own and/or secure through a contract. APCo and WPCo both meet their capacity obligations in PJM by supplying their resources through the FRR option.

Q. BRIEFLY, DEFINE "SELF-SCHEDULING" AND HOW THAT RELATES TO BEING AN FRR ENTITY.

A. Self-scheduling refers to the unit commitment status of Must-Run, available to all generating units participating in the PJM energy markets. It is an option available to generating units regardless of whether they are FRR, like the Companies' generating resources, or are sold into PJM's Reliability Pricing Model capacity auctions.

Q. WITH THAT BACKGROUND AND CONTEXT, IS IT YOUR TESTIMONY THAT THE COMPANIES ARE MAXIMIZING THE SCHEDULING OF THEIR UNITS IN A REASONABLE AND PRUDENT MANNER?

A. Yes. As I will explain later in my testimony, the Companies have prudently employed the Must-Run commitment status to keep their coal-fired units online generating energy when they believed it was the best option for customers.

MARKET OVERVIEW

Q. PLEASE DESCRIBE THE COMPANIES' DAILY ACTIVITIES IN THE PJM ENERGY MARKETS.

A. Every day the Companies offer all their available generating resources and purchase all of their expected load in the PJM Day-Ahead energy market. The offering of the Companies' generation resources involves submitting a large volume of data to PJM that includes unit commitment designations, offer curves that cover per-unit costs for the range of output from economic minimum to economic maximum, and market parameters. This process involves a high level of constant and iterative coordination among AEPSC Commercial Operations personnel, AEPSC Fuel Procurement personnel, and generating unit personnel located at individual plant sites. The purpose of this intensive process is to provide the most up-to-date and accurate information to PJM prior to the market deadline. Commercial Operations relies on the generating unit personnel to provide the most up-to-date information on each generating unit's availability and capability. Commercial Operations relies on Fuel Procurement to provide the most up-to-date information on fuel availability and pricing, especially for natural gas, which has prices that change on a daily basis. The daily process concludes when Commercial Operations compiles and submits all information required by PJM in advance of the Day-Ahead market deadline.

Q. PLEASE DESCRIBE THE UNIT COMMITMENT DESIGNATIONS REFERENCED ABOVE IN MORE DETAIL.

A. As part of the Companies' daily submission to the PJM Day-Ahead energy market, they must provide a unit commitment designation for each unit. The designations are economic, must-run, emergency, or not available.

Economic units are committed and dispatched via PJM's economic dispatch model.

Must-run units, also called self-committed or self-scheduled units, are committed into the Day-Ahead market to run at their economic minimum, although the PJM economic dispatch model can run them at a level above their economic minimum.

An emergency status indicates that a unit is available only for emergency dispatch. A status of not available identifies units that are in an outage and incapable of delivering energy into the market.

Q. PLEASE DESCRIBE THE OFFER CURVES REFERENCED ABOVE IN MORE DETAIL.

A. For each operating day, the Companies submit offer curves to PJM for each generating unit that provide incremental generation costs from a unit's economic minimum level of output to its economic maximum. The first offer curve is a cost-based offer curve, strictly defined by the rules established in PJM Manual 15 and subject to a Fuel Cost Policy filed with PJM's

Independent Market Monitor. The cost-based offer curve is used by PJM when a generating unit is dispatched for reliability purposes under Schedule 1 Section 6 of the PJM Operating Agreement.

The second offer curve is a market offer curve which is not strictly regulated, although PJM and the Federal Energy Regulatory Commission have a set maximum allowed value. To clarify, both the Companies' market offer curves and cost-based offer curves include fuel costs, variable fuel transportation costs, emissions and pollution reagent costs, and variable operations and maintenance expenses. PJM can utilize either of these offer curves to determine dispatch for each unit, but most often utilizes the market offer curve.

Q. PLEASE DESCRIBE THE MARKET PARAMETERS REFERENCED ABOVE IN MORE DETAIL.

A. The market parameters submitted to PJM daily include, but are not limited to, a unit's startup cost, startup time in hours, how quickly a unit can ramp-up energy production, and other characteristics defined in PJM protocols. PJM protocols are established in various documents such as the PJM tariff, PJM manuals, and the PJM Operating Agreement, all of which are published on www.pjm.com. Utilizing the daily information provided, PJM determines the economic dispatch for the Day-Ahead energy market and publishes the results.

Q. HOW DOES THE COMPANIES' PARTICIPATION IN PJM ENERGY MARKETS SERVE THE INTERESTS OF THE COMPANIES' CUSTOMERS?

A. As Load Serving Entities in PJM, participation in the market allows the Companies to serve customers with energy from PJM when Company-owned generation is either insufficient or more expensive than market prices. The benefits of participation in PJM include improved reliability and lower prices. As Generation Owners, participation offers the Companies the opportunity to sell generation in excess of the Companies' needs when market prices exceed the Companies' offer prices. Sales in excess of the Companies' demand are off system sales that reduce customer costs.

Q. DO THE COMPANIES HAVE COMPLETE CONTROL OVER THE DISPATCH OF THEIR GENERATING UNITS AND, IF NOT, WHAT ULTIMATELY DETERMINES THE LEVEL OF OUTPUT FOR A GENERATING UNIT?

A. No. PJM, through its economic dispatch model, determines the ultimate level of generation required to meet the load based on the units available in each hour and the economics of those units. In basic terms, using the offer curves from every available unit as well as operational information like each unit's ability to ramp up and ramp down generation, PJM determines the lowest cost to serve its load in each hour. During any given hour, the

Companies' units may well not be the lowest cost units to dispatch. This allows PJM to determine the amount of available generation and cost of available generation. All available generation is then "stacked" from lowest cost to highest cost, and the resulting energy market price reflects the highest cost unit needed to serve load in each hour while also managing the transmission system by factoring in transmission constraints.

Based on the results of PJM's economic dispatch, the Companies may need to start up, shut down, or make decisions for the future economic run of an online generating unit. The PJM model is continuously updated in the Real-Time market to adjust for changing conditions in order to optimize the dispatch instructions that seek to provide the least cost solution to meet the PJM market's overall load.

As I stated, this is beneficial to the Companies' customers because it ensures that the lowest cost units are prioritized to serve the load and ensures that the Companies are not operating their units at a loss. This dynamic is important because, when the Companies' load is in excess of its supply resources, or the PJM market produces energy at a lower cost than the Companies' own resources can, the Companies' customers will be responsible for the lower of internal cost to produce or the market price for spot energy.

Q. OVER WHAT TIME PERIOD DO PJM's COMMITMENT AND DISPATCH DECISIONS OCCUR?

A. The Day-Ahead market addresses energy needs in the next calendar day, while the Real-Time market addresses energy needs in the moment.

Q. DOES PJM PLACE ANY OBLIGATIONS ON THE AVAILABILITY OF GENERATING UNITS?

A. Yes. The first obligation is that any generating unit that is a capacity resource must offer its energy into the Day-Ahead energy market. Specifically, if a generating unit either sells its capacity through the PJM capacity auctions or supplies capacity through a FRR plan, it must offer its energy every day in the Day-Ahead energy market. All the Companies' supply resources are included in their FRR plan and therefore must be offered into the energy markets each day. While this obligation requires all the Companies' generation resources to participate in the energy markets, for the reasons I have discussed, it does not always result in a decision by PJM to commit and dispatch individual generating units. The Companies' participation in the energy markets is further discussed later in my testimony.

The second obligation is that all scheduled generating unit outages must be approved by PJM before the units are allowed to be taken out of service. This includes taking units out of service for either a Planned or a Maintenance Outage, both of which are further discussed by Company

witness Bumgarner. PJM also explicitly prohibits Planned Outages during PJM Peak Period Maintenance Season, which is defined as those weeks containing the 24th Wednesday (June 9 in 2025) through the 36th Wednesday (September 5 in 2025) of each year. Peak Period Maintenance Season begins on the Monday and ends on the Friday of the period described above.[1]

Q. HOW DO THESE TRANSACTIONS RESULT IN SALES TO AND PURCHASES FROM PJM?

A. In every hour for a given period, the Companies are buying and selling energy into the PJM Day-Ahead and Real-Time energy markets. If one of the Companies purchases more energy than it sells into PJM in an individual hour, the result is a purchased power transaction. If one of the Companies sells more energy than it purchases in an individual hour, the result is an off-system sale. It is possible for the Companies to have both sales to and purchases from PJM in any given time period.

Q. HOW DO THE COMPANIES' ACTIVITIES IN PJM IMPACT THE COSTS RECOVERED THROUGH ENEC RATES?

A. The Companies incur fuel and related expenses from their own generation resources, expenses for power purchased from their contracted resources and, in hours when the load purchased exceeds the generation sold to PJM,

[1] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/2016-2057-peak-period-maintenance-seasons.ashx

expenses for power purchased from the PJM market. In hours when one of the Companies makes off-system sales, the revenues from those sales are credited back to customers.

MARKET OPERATIONS DURING THE ENEC REVIEW PERIOD

Q. PLEASE DESCRIBE THE STATE OF THE PJM ENERGY MARKETS DURING THE REVIEW PERIOD.

A. Overall, PJM energy market prices in 2025 were higher than they were in 2024. Specifically, the real-time load weighted Location Marginal Price ("LMP") increased by 50.4% in 2025 from the 2024 price levels. In 2025, the real-time load weighted LMP increased from $33.74 per MWh to $50.73 per MWh. Of the $16.99 per MWh increase, $9.94 per MWh was in the fuel and consumables cost components of LMP. Figure 1 below is from PJM's 2025 State of the Market report and reflects the components of the increase. The real time average hourly load increased in 2025 as well, from 89,274 MWh to 92,568 MWh.[2]

[2] PJM 2025 State of the Market Report, Volume 2, page 21, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-vol2.pdf

Figure 1

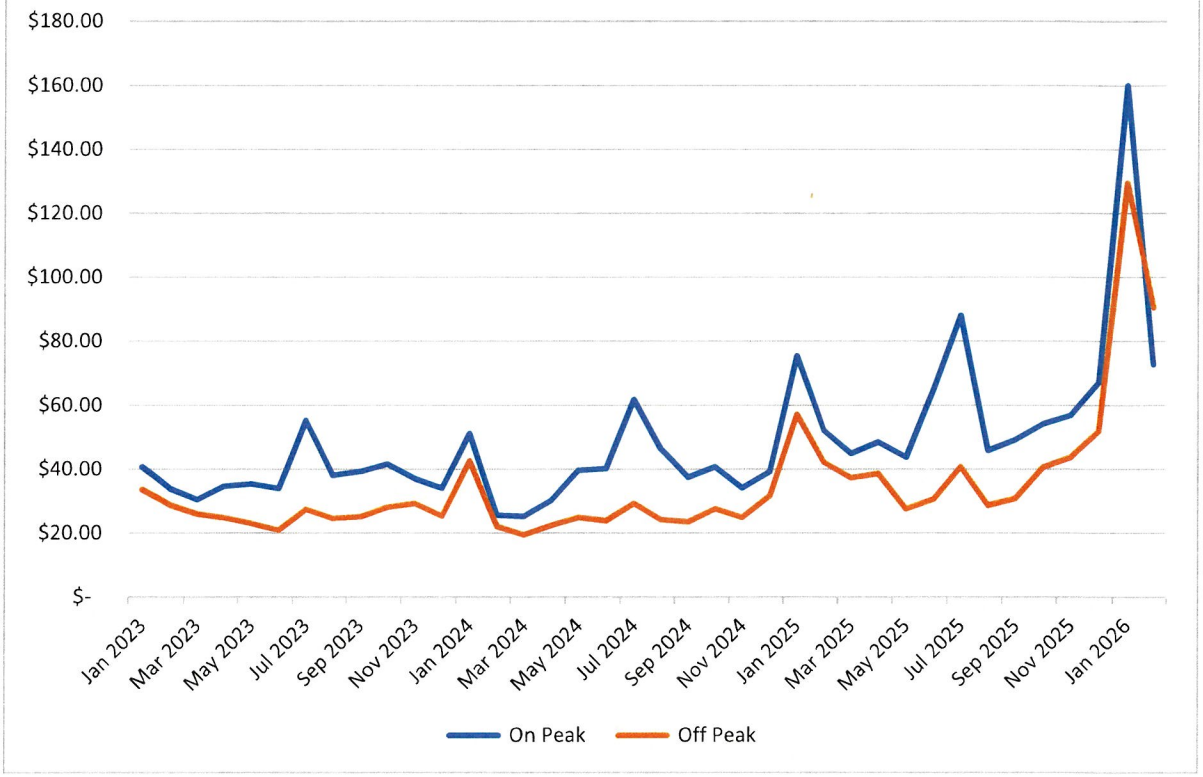
Table 3-72 Components of change in real-time load-weighted average LMP: 2024 and 2025

Component	2024	2025	Change in LMP	Percent of Total Change
Fuel and Consumables	$20.06	$29.99	$9.94	58.5%
Emission Related	$3.19	$3.44	$0.25	1.5%
Market Power Related	$5.16	$6.35	$1.20	7.1%
Scarcity	$0.17	$1.00	$0.83	4.9%
Transmission Constraint Penalty Factor	$3.01	$5.65	$2.64	15.5%
Ancillary Service Redispatch Cost	$1.33	$1.27	($0.06)	(0.3%)
Pre-emergency Demand Response	$0.00	$0.67	$0.67	4.0%
PJM Administrative Cap	$0.00	($0.08)	($0.08)	(0.5%)
All Other	$0.82	$2.43	$1.60	9.4%
Total Change	$33.74	$50.73	$16.99	100.0%

Q. PLEASE DESCRIBE THE TREND IN PJM MARKET PRICES DURING 2024 AND 2025 UP TO THE BEGINNING OF 2026.

A. As can be seen in Figure 2 below, the energy markets of 2024 and 2025 showed steady price increases versus the low prices in 2023 with sharper peaks during months when winter or summer weather increased energy demand and, therefore, average market prices. For example, the highest monthly peak hour average in 2025 was $88.00 in July 2025 compared to an average of $61.80 per MWh in July 2024, a 42% increase. Prices in the off-peak hours followed a similar trend with the highest monthly average of $57.14 per MWh occurring in January 2025 compared to an average of $42.50 in January 2024, a 34% increase. The graph also displays the extreme price spikes in January 2026, due to Winter Storm Fern that were experienced across the PJM footprint. In January 2026, the average peak price was $160 per MWh and an average off-peak price was $129.50.

Figure 2
PJM Monthly Average Peak and Off-Peak Day Ahead LMPs

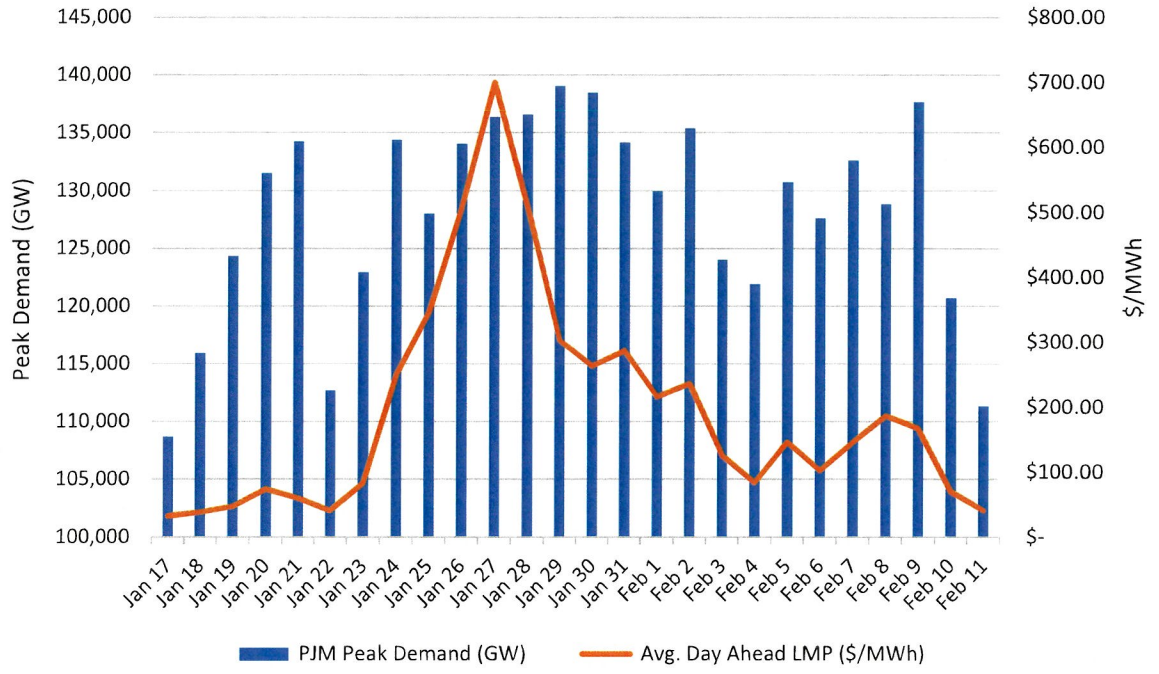


PJM classifies weekday hours between 7 a.m. and 11 p.m. as on-peak hours, except for NERC holidays. All other hours are off-peak hours.

As shown in Figure 2, and in more detail in Figure 3 below, prices sharply spiked in January 2026. This is largely due to extremely cold temperatures in the last week of the month, which included Winter Storm Fern from January 23 – 27. PJM issued a continuous Cold Weather Alert covering January 24 through February 2 and further issued a Level 1 Emergency Energy Alert (EEA1) for January 27. January 2026 also included PJM's sixth highest winter peak on January 29 and eighth highest peak on January 30. As I will discuss below, the Companies units produced

significant economic benefits for the Companies' customers during this period.

Figure 3
Peak PJM Load and Avg. Day Ahead LMP
Jan. 17 - Feb. 11, 2026

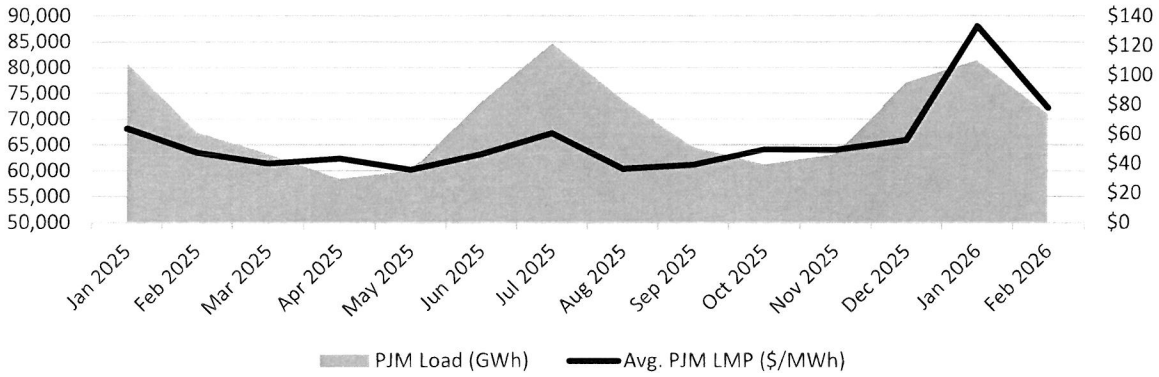


Q. PLEASE DESCRIBE THE RELATIONSHIP BETWEEN ENERGY MARKET PRICES AND ENERGY DEMAND DURING THIS PERIOD.

A. As illustrated in Figure 4 below, total PJM load experienced seasonal fluctuation throughout 2025 and the early months of 2026, with load rising during the summer and winter months in response to seasonal cooling and heating needs, respectively. However, as January 2025 and January 2026 show, there was an increased sensitivity to winter weather compared to

summer weather, which is due to higher levels of demand for natural gas during the winter heating season.

Figure 4
Total PJM Load and Monthly Average LMP's



THE COMPANIES' OPERATIONS IN PJM

Q. PLEASE DESCRIBE HOW THE COMPANIES PARTICIPATE IN THE PJM ENERGY MARKETS.

A. As stated above, the Companies use their generating resources to meet their capacity obligations under a FRR plan and, therefore, offer all their available generation into the PJM markets every day. In addition, they purchase all their load each day. While they attempt to do this entirely through the Day-Ahead energy market, the PJM Real-Time energy market exists to accommodate any changes in either expected generation or expected load. But, as I testified above, this does not mean PJM - due to market conditions and market pricing - will dispatch the Companies' units.

Q. DID THE COMPANIES' COAL-FIRED GENERATING UNITS PRODUCE A BENEFIT TO CUSTOMERS DURING THE REVIEW PERIOD?

A. Yes. APCo's coal-fired units at the Amos Plant and the Mountaineer Plant, together with the WPCo share of the coal-fired units at the Mitchell Plant, produced approximately $339.5 million of revenues in excess of the expenses for coal consumption, fuel handling, pollution reagents (consumables), and emission allowances. The results for the Review Period are summarized by plant in Figure 5 below and presented by plant on a monthly basis in APCo/WPCo JMS-D Attachment 1.

Figure 5 - Net Revenues from Coal-Fired Power Plants

	Amos Plant	Mountaineer Plant	Mitchell Plant (WPCo)	Total
PJM Energy Revenues	$504,746,191	$378,908,365	$135,756,237	$1,019,410,793
Coal Consumption	$295,755,387	$199,484,393	$79,135,842	$574,375,622
Fuel Handling	$34,081,393	$20,071,822	$11,685,767	$65,838,982
Consumables	$21,501,542	$14,436,356	$3,512,401	$39,450,299
Allowances	$190,636	$75,641	$121	$266,398
Total Expenses	$351,528,958	$234,068,212	$94,334,131	$679,931,301
Net Revenues	$153,217,232	$144,840,153	$41,422,106	$339,479,492

Q. ARE THERE COMPLEXITIES THAT THE COMPANIES' COAL-FIRED GENERATING UNITS MUST NAVIGATE WHEN PARTICIPATING IN THE PJM ENERGY MARKETS?

A. Yes, I have testified to some of those complexities and the extensive coordination required within the Companies. For the Companies' coal units

in particular, managing participation in the PJM market in conjunction with managing coal inventories and supply is an extremely complex process. Like any coal plant, the Companies' coal-fired plants must actively manage their fuel inventories in support of their ongoing efforts to participate in PJM energy markets. During periods of high PJM energy market prices, inventory management focuses on maintaining sufficient inventory to provide reliable service while accounting for the ability to replenish coal that is consumed. During periods of low market prices, inventory management focuses on actively managing contracts and deliveries to ensure inventory levels do not exceed a plant's ability to safely store coal on site. At times when coal inventory levels are expected to exceed the plant's safe storage limits and the plant is unable to modify contracts or deliveries, a market strategy may be employed to increase generation instead of risking the safety of plant personnel.

Q. PLEASE DESCRIBE HOW THE COMPANIES ACTIVELY MANAGED THEIR COAL SUPPLY.

A. The Companies actively managed their coal supply by monitoring existing inventories, monitoring deliveries, monitoring current and forward PJM energy prices, actively engaging with coal suppliers to defer deliveries or exit/amend contracts, and using market strategies to increase coal consumption. In addition, the Companies can use market strategies to

actively manage coal inventories. Regardless of whether or when the Companies choose to act, all factors are continually monitored as new information becomes available and market conditions change.

Q. PLEASE DESCRIBE THE MARKET STRATEGIES AVAILABLE TO THE COMPANIES TO MANAGE COAL INVENTORIES.

A. While the level of hourly generation by Companies' generating units is subject to PJM dispatch, there are strategies available to the Companies to ensure their generating units can increase output in order to manage coal inventories that risk exceeding safe storage levels. The Companies can (1) utilize a Must-Run commitment status, which results in a unit being automatically dispatched at its economic minimum level of output: (2) lower the price of its market offers to PJM; or (3) employ a combination of the two strategies. However, each of these actions could cause the Companies to potentially sell generation to PJM at a loss; so their use in coal inventory management is limited to times when the Companies' alternative options are projected to be more expensive.

Given that these strategies are available to the Companies in daily operations, the Companies may also reflect these strategies in their forecasts. If the Companies' forecasted generation and associated coal consumption calculated by Company witness Stanek do not reflect sufficient consumption to keep forecasted inventories within plant limits, Company

witness Stanek calculates updated forecast values for additional generation and associated coal consumption that reflect these market strategies.

Q. DID THE COMPANIES USE A MARKET STRATEGY TO INCREASE COAL CONSUMPTION DURING THE REVIEW PERIOD?

A. Yes, but the use of the market strategy was extremely limited. The units at the Amos and Mountaineer Plants did not experience any inventory concerns during the Review Period. In contrast, with Mitchell Unit 1 in an outage, Mitchell Unit 2 was committed with a Must-Run status for five days in March 2025 to address projections of unsafe storage levels for its high sulfur coal inventory. In early March, projections showed that the Mitchell Plant would exceed safe storage limits for its high-sulfur coal inventory in June and again starting in September, with projected burns in the final four months of 2025 never reaching a level of consumption that would result in a high-sulfur coal inventory level below the safe storage limit. Based on the data prepared by Company witness Bumgarner, this resulted in the generation of 17,397 Megawatt-hours of energy and the consumption of 15,800 tons of coal.

Q. WERE THE COMPANIES' IMPLEMENTATION OF THEIR MARKET STRATEGIES FLEXIBLE AND RESPONSIVE TO CHANGING CIRCUMSTANCES?

A. Yes. Market offer strategies are agreed upon prior to start of each new month, but the application and management of these strategies change as market conditions change. The goal was and is always to provide value and minimize energy costs to customers. As described above, fuel consumption, fuel delivery, short-term market prices, forward market prices, unit availability, and environmental limitations were evaluated by the Companies to remain flexible in response to changing circumstances. The Companies' limited use of a market strategy during the Review Period demonstrates their attentiveness to these factors and their willingness to adjust their strategy. Regardless of whether a market strategy was used, the goal of minimizing costs to customers remained the same.

Q. CAN YOU PROVIDE EXAMPLES OF SUCH ADJUSTMENT?

A. Yes. When managing the risks of exceeding storage limits of coal, forecast inventory levels change in response to forecasted consumption, forecasted deliveries, and changes in the market forward price curve. Forecasted consumption is driven by market prices, reflected in market forward price curve, inventory prices, and unit availability. For example, the risks of exceeding storage limits rise due to unplanned outages or an updated

forward price curve showing lower market energy prices. In response, the Companies would update their analysis and determine if their current market offer strategy needs to be adjusted. Forecasted deliveries change as a result of the efforts of Company witness Chilcote and her team to modify contracted deliveries. The Companies would also update their analysis in order to determine if a change in their market offer strategy is necessary. By updating their analysis and reevaluating their market strategy in response to new information, the Companies focus on minimizing costs to their customers.

Q. PLEASE DESCRIBE THE ECONOMIC ANALYSIS USED BY THE COMPANIES TO EVALUATE THE USE OF A MARKET STRATEGY TO MANAGE THEIR COAL SUPPLY.

A. This analysis compares the economic impact of the Companies' market strategy to the economic impact of contract violations. The economic impact of the market strategy is the net margins resulting from the hours when the Companies committed their coal-fired generating units with a Must-Run commitment status solely for the purpose of managing their coal inventories. Net margins reflect the Companies' revenues from selling energy into the PJM energy market, less the incremental costs of generating that energy. The incremental costs include fuel, fuel handling, consumables, allowances, and variable operations and maintenance expenses (O&M).

The economic impact of coal contract violations is the total cost the Companies would have incurred for coal which they would have been unable to receive. It reflects the weighted average cost of purchased coal per ton for each plant and the tons consumed during the hours when the units ran for fuel inventory management.

Q. DID THE COMPANIES' STRATEGIES TO MANAGE THEIR COAL INVENTORIES RESULT IN A LOWER COST TO CUSTOMERS?

A. Yes. Using coal consumption data for the Mitchell Plant provided by Company witness Bumgarner, Mitchell Unit 2 consumed 7,900 tons of coal during March when a Must-Run commitment status was used for coal inventory management. This generation produced $684,173 in energy revenues and resulted in fuel expense of $738,912, calculated using the average per-ton cost of consumption. This net loss of $54,738 results in a cost of $6.93 per ton, far below the cost of deliveries in March 2025 or high-sulfur coal deliveries for the remainder of the Review Period.

Q. DID THE COMPANIES USE THE MUST-RUN COMMITMENT STATUS FOR THEIR COAL-FIRED PLANTS DURING THE REVIEW PERIOD?

A. Yes, although the use was limited to 15% of hours during the Review Period for the Amos and Mitchell Plants and to 18% of hours for the Mountaineer Plant. The Companies were often able to commit their coal-fired units with an Economic commitment status when the units were available.

Q. WHY DID THE COMPANIES USE THE MUST-RUN COMMITMENT STATUS DURING THE REVIEW PERIOD?

A. Aside from its limited use to manage fuel inventories at the Mitchell Plant, throughout the Review Period, the Companies used the Must-Run commitment status to both manage their units' economics beyond the 24-hour period covered by the PJM Day-Ahead market and for operational purposes. As shown in Figure 6 below, the most common reason the Companies identified when selecting a Must-Run commitment status was Forecasted Near Term Economics. This justification indicates that the Companies believed that keeping the units online and operating to take advantage of future price increases would benefit customers compared to shutting the units down and increasing purchases from PJM.

The Companies also committed units with a Must-Run commitment status for operational purposes, specifically Testing and Supply Steam for Unit Startup. When units are scheduled to undergo testing, either their required PJM capacity testing or environmental testing, units are committed with a Must-Run status to ensure optimal use of Company staff and third-party experts rather than risk a unit not being selected for commitment and dispatch, thus disrupting the planned test. The Companies also kept units online during the course of the year to utilize heat and steam from a co-located unit, thereby reducing startup complexity and costs.

The final reason, one only used by Amos Unit 3 in January 2026, was for both economic and operational purposes. Amos Unit 3 was committed with a Must-Run status to keep the unit online in advance of the cold weather that became Winter Storm Fern. This allowed the unit to maintain operational stability while avoiding a startup immediately after shutting down so that the unit could deliver low-cost energy during what was expected to be, and was, a period of high PJM energy market prices.

Figure 6

Percentage of Must Run Hours
By Justification

	Amos Plant				Mountaineer Plant				Mitchell Plant				
	Supply Steam for Unit Start-up	Forecasted Near Term Economics	Weather	Testing	Supply Steam for Unit Start-up	Forecasted Near Term Economics	Weather	Testing	Supply Steam for Unit Start-up	Forecasted Near Term Economics	Weather	Testing	Fuel Inventory Management
Mar 2025	-	100.0%	-	-	-	100.0%	-	-	-	-	-	-	100.0%
Apr	-	100.0%	-	-	-	100.0%	-	-	-	100.0%	-	-	-
May	-	100.0%	-	-	-	100.0%	-	-	-	100.0%	-	-	-
Jun	-	81.8%	-	18.2%	-	100.0%	-	-	-	100.0%	-	-	-
Jul	-	20.0%	-	80.0%	-	-	-	-	-	66.7%	-	33.3%	-
Aug	-	82.6%	-	17.4%	-	100.0%	-	-	9.7%	48.3%	-	42.1%	-
Sep	-	52.2%	-	47.8%	-	100.0%	-	-	-	-	-	-	-
Oct	-	100.0%	-	-	-	-	-	100.0%	25.0%	8.3%	-	66.7%	-
Nov	71.4%	28.6%	-	-	-	-	-	-	-	80.0%	-	20.0%	-
Dec	10.0%	86.7%	-	3.3%	-	100.0%	-	-	22.2%	77.8%	-	-	-
Jan 2026	1.5%	57.0%	41.5%	-	-	100.0%	-	-	-	100.0%	-	-	-
Feb	-	-	-	-	-	66.7%	-	33.3%	-	86.7%	-	13.3%	-
Total	5.1%	78.5%	4.9%	11.5%	-	94.0%	-	6.0%	6.2%	68.3%	-	21.0%	4.4%

Q. IS THE COMPANIES' USE OF THE MUST-RUN COMMITMENT STATUS RESPONSIVE TO THIS COMMISSION'S ORDER IN CASE NO. 24-0854-E-42T, AND, IF SO, CAN YOU SUMMARIZE YOUR RESPONSE?

A. Yes. In the context of all of the complexities about which I testify, the Companies seek to maximize the generation of their units through economic dispatch, and when necessary, the use of a Must-Run commitment status. The Companies' use of the Must-Run commitment status allowed them to

keep units online in order to provide benefit to customers over a period of time longer than that addressed in PJM's Day-Ahead market. As implied in the Commission's Order, the Companies have some flexibility under the PJM protocols to generate energy at times when PJM's Day-Ahead dispatch might not otherwise dispatch the Companies' units; however, the Companies use this flexibility judiciously. The Companies made diligent and prudent efforts that kept coal-fired units online in advance of forecasted price increases, expected weather events, required testing, and co-located unit startups. This flexibility was used prudently to benefit customers based on information available to the Companies at the time of their decision.

Q. IN CONCLUSION, PLEASE SUMMARIZE THE COMPANIES' USE OF A MUST-RUN COMMITMENT STATUS DURING THE REVIEW PERIOD.

A. The Companies' PJM energy market offer strategy for their generating units is consistent, prudent, and reasonable, as are all of the many iterative analyses and actions that I describe which must often occur on a real-time basis in support of that strategy. The Companies used the Must-Run commitment status to manage fuel inventory, keep units online in advance of projected increases in market prices, and to manage operational issues such as testing and startup of a co-located unit. During the Review Period, the Companies actively managed their coal inventories based on the best information available to them at the time in a way that minimized ENEC

energy supply costs under the circumstances and prevented the Companies from exceeding maximum storage levels at their plants.

FOSSIL FLEET PERFORMANCE

Q. HOW DID THE APPLICATION OF THE COMPANIES' STRATEGY AFFECT THE TOTAL AMOUNT OF COAL GENERATION?

A. The Companies' PJM market offer strategy for their coal units likely resulted in additional generation from their coal-fired units, but as I discuss below, did not result in an extraordinary level of dispatch compared to other coal-fired generating units in PJM.

Q. PLEASE DESCRIBE THE COMPANIES' COAL AND GAS NET CAPACITY FACTORS AND HOW THEY COMPARED TO COAL-FIRED AND GAS-FIRED RESOURCES ACROSS THE ENTIRE PJM RTO.

A. Figure 7 below includes the net capacity factors achieved by the Companies' coal and gas units during this ENEC review period.

Figure 7

Net Capacity Factors - Coal & Gas			
Primary Fuel Description	**Plant**	**Unit Name**	**12 Mos. Ending Feb 26**
Coal	**Amos Plant**	Amos 1	42.21
		Amos 2	32.02
		Amos 3	25.76
	Amos Plant Total		**32.00**
	Mitchell Plant	Mitchell 1	24.53
		Mitchell 2	35.75
	Mitchell Plant Total		**30.21**
	Mountaineer Plant	Mountaineer 1	58.64
	Mountaineer Plant Total		**58.64**
Coal Total			**37.55**
Gas/Steam	**Ceredo Plant**	Ceredo 1	18.03
		Ceredo 2	17.66
		Ceredo 3	19.76
		Ceredo 4	19.51
		Ceredo 5	14.73
		Ceredo 6	13.37
	Ceredo Plant Total		**17.17**
	Clinch Plant	Clinch River 1	5.34
		Clinch River 2	6.50
	Clinch Plant Total		**6.02**
	Dresden Plant	Dresden 1A	73.60
		Dresden 1B	72.15
		Dresden 1S	66.46
	Dresden Plant Total		**70.37**
Gas/Steam Total			**35.52**

Figure 8 below is from PJM's 2025 state of the market report and includes the same information by resource type for the entire PJM generating fleet over the past two calendar years.

Figure 8

Table 5-35 Capacity factor (By unit type (GWh)): 2024 and 2025[231] [232] [233]

	2024		2025		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Capacity Factor
Battery	51.8	1.8%	80.7	2.4%	0.7%
Combined Cycle	334,577.3	66.0%	324,774.5	62.8%	(3.1%)
Single Fuel	287,727.8	70.8%	282,215.5	67.8%	(3.0%)
Dual Fuel	46,849.5	46.4%	42,559.0	42.3%	(4.1%)
Combustion Turbine	22,750.9	9.0%	26,193.7	10.4%	1.4%
Single Fuel	14,301.1	8.2%	16,471.7	9.4%	1.2%
Dual Fuel	8,449.9	10.9%	9,722.0	12.6%	1.7%
Diesel	324.6	12.5%	365.6	12.1%	(0.4%)
Single Fuel	298.4	12.9%	312.3	11.5%	(1.5%)
Dual Fuel	26.2	8.7%	53.3	17.7%	9.0%
Diesel (Landfill gas)	901.9	49.6%	756.8	41.2%	(8.3%)
Fuel Cell	215.2	89.5%	216.9	93.5%	4.0%
Nuclear	272,744.4	95.1%	270,642.3	94.7%	(0.5%)
Pumped Storage Hydro	8,143.8	17.1%	8,346.8	17.4%	0.3%
Run of River Hydro	7,857.6	43.5%	7,116.2	32.2%	(11.4%)
Solar	17,261.3	19.1%	24,780.7	21.4%	2.3%
Steam	137,407.9	33.4%	162,256.5	40.0%	6.6%
Biomass	4,993.7	64.8%	5,123.8	65.6%	0.8%
Coal	119,918.0	36.1%	143,558.6	44.0%	7.8%
Single Fuel	119,918.0	36.7%	143,558.6	44.5%	7.9%
Dual Fuel	0.0	0.0%	0.0	0.0%	0.0%
Natural Gas	11,341.0	46.0%	12,378.0	44.9%	(1.1%)
Single Fuel	519.9	54.0%	517.1	52.5%	(1.5%)
Dual Fuel	10,821.1	27.3%	11,860.9	26.7%	(0.6%)
Oil	1,155.2	4.1%	1,196.2	4.5%	0.4%
Wind	31,383.8	16.1%	32,223.1	17.9%	1.8%
Total	833,620.5	48.3%	857,753.9	48.7%	0.4%

As can be seen, the Companies' coal and combustion turbine resources are close to, or in line with, PJM RTO averages. For example, the Companies' coal plants experienced a combined capacity factor of 37.55%, which is below the PJM 2025 average of 44.5%, but that value is largely the result of outages at Amos Unit 3 and Mitchell Unit 1. Amos Unit

1 1 was very close to the PJM coal plant average while Mountaineer exceeded
2 it. In addition, the Dresden plant exceeded the PJM 2025 average for
3 combined cycle units.

4 **Q. DID THE PJM AVERAGE PRICE OF $55.34 PER MWH DURING THE**
5 **ENEC REVIEW PERIOD AFFECT THE VALUE OF THE COMPANIES'**
6 **COAL-FIRED GENERATING UNITS AS A HEDGE AGAINST MARKET**
7 **PRICES?**

8 A. No. The purpose of a hedge is to provide price stability in the face of market
9 price instability, not to guarantee the lowest possible price. Therefore, the
10 value of a hedge derives not from being lower than the market price but from
11 its stable and consistent cost over long periods, especially when markets
12 are subject to significant spikes due to external events like extreme weather.
13 Throughout the Review Period, prices remained relatively stable and
14 consistent. The Companies' coal-fired generating units continue to provide
15 generation at a relatively steady level of costs, just as they did during the
16 previous ENEC review period. While coal prices rise and fall with gas and
17 market energy costs, there is a lag in realized coal costs resulting from the
18 procurement and transportation of coal versus gas and energy. Contracted
19 for coal needs to be shipped to the plant in question, averaged into the
20 overall coal pile/fuel cost of the units and then burned to be reflected in

customers' ENEC costs. Conversely, gas and energy market fluctuations are realized from an ENEC cost perspective on an hourly basis.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ATTACHMENT 4

REBUTTAL TESTIMONY OF JASON M. STEGALL

REBUTTAL TESTIMONY OF
JASON M. STEGALL
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF
WEST VIRGINIA IN CASE NO. 26-0469-E-ENEC

Q. PLEASE STATE YOUR NAME.

A. My name is Jason M. Stegall.

Q. ARE YOU THE SAME JASON M. STEGALL WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. FOR WHOM ARE YOU TESTIFYING ON REBUTTAL?

A. I am testifying on behalf of both Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo") (collectively, the "Companies").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the findings and recommendations of Emily Medine, a witness who filed testimony on behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia ("CAD").

Q. WHAT ISSUES FROM MS. MEDINE'S TESTIMONY WILL YOU BE ADDRESSING?

A. I will be addressing Ms. Medine's claim that the Companies, "failed to develop and implement a strategy that would have allowed the Companies'

plants to operate at a higher capacity factor."[1] Ms. Medine also makes a recommendation to the Commission that the Companies, "should be directed by the Commission to explore multiple options that could improve the dispatch of their coal plants."[2]

Q. PLEASE IDENTIFY THE KEY ASPECT MISSING FROM BOTH MS. MEDINE'S CLAIM AND HER RECOMMENDATION TO THE COMMISSION.

A. Ms. Medine fails to align any proposal to increase the dispatch of the Companies' coal-fired generating units with a customer benefit, making her proposals appear as if increased dispatch is a goal on its own, without consideration of customer impacts. As the Companies established in their direct testimony in this proceeding, any proposal to increase dispatch of the Companies' coal-fired units should be focused first and foremost on reducing, not increasing, costs for customers. As Ms. Medine notes throughout her testimony in reference to prior ENEC cases as well as the current case, the Companies have employed market strategies to increase dispatch for the purposes of increasing coal consumption. However, as I note in my direct testimony, "The goal was and is always to provide value and minimize energy costs to customers."[3]

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[1] Corrected Direct Testimony of E. Medine, page 4 (Bates 000007), lines 10-11.
[2] *Ibid.*, page 5 (Bates 000008), lines 4-5.
[3] Direct Testimony of J. Stegall, page 23 (Bates 0336), lines 6-7.

Q. WOULD THE IMPLEMENTATION OF ANY OF THE OPTIONS LISTED BY CAD WITNESS MEDINE ON PAGE 27 (BATES 000030) OF HER CORRECTED TESTIMONY RESULT IN A REDUCTION IN CUSTOMERS' COSTS?

A. No. Increasing dispatch, when it is uneconomic to do so, will result in additional costs to the Companies' customers. Again, the Companies explained this in their direct testimony. Furthermore, such a strategy is likely to result in disallowances of the Companies' costs in its Federal Energy Regulatory Commission (FERC) and Virginia retail jurisdictions. The Commission would need to authorize recovery of those costs from West Virginia customers.

Q. WOULD THE OPTIONS SUGGESTED BY CAD WITNESS MEDINE THAT RESULT IN A REDUCTION TO THE COMPANIES' MARKET OFFER CURVES GUARANTEE A HIGHER LEVEL OF DISPATCH?

A. No. Any strategy that employs a reduction in the market offer curve to increase dispatch must take market prices into account. As I discuss on page 20 (Bates 0333) of my direct testimony, the Companies monitor forward PJM energy prices as part of their active management of coal supply. The size of a decrement used to increase dispatch must be determined with knowledge of both a generating unit's offer cost, provided in its market offer curve, and expected market prices. Modifying the market offer without an evaluation of market price would likely result in a decrement

that fails to achieve the desired effect, because it is too small, or has no impact at all, because the unit is already economic.

Q. DO YOU HAVE ADDITIONAL CONCERNS WITH THE OPTIONS SHE IDENTIFIES?

A. Yes. If the use of a decrement does result in increased generation, the cost of that generation will not change just because the offer cost was reduced. As a basic concept, this is a mistaken belief that higher sales of energy can overcome selling energy at a loss when in reality such a tactic results in additional losses that would be borne by customers.

Q. ARE THERE SIGNIFICANT FACTORS EXCLUDED FROM MS. MEDINE'S COMPARISON OF THE COMPANIES TO LOUISVILLE GAS & ELECTRIC COMPANY AND KENTUCKY UTILITIES (LGE/KU), WHICH BEGINS ON PAGE 40 (BATES 000043) OF HER CORRECTED TESTIMONY?

A. Yes. LGE/KU do not participate in a Regional Transmission Organization (RTO) like PJM. Any comparison of LGE/KU to the Companies needs to recognize the benefits and drawbacks of each. Witness Medine only recognizes the benefit, that LGE/KU's independence allows them the freedom to manage their coal supply without regard to economics. This means they can purchase coal without any consideration of future energy market prices. The drawback is that their customers are exposed to energy prices above the market prices of RTOs like PJM.

A major drawback of not participating in an RTO, and one more critical than price, is the increased risk that LGE/KU will be unable to meet high levels of demand, especially during major weather events. For example, during Winter Storm Elliott, LGE/KU had to implement rolling blackouts in order to maintain their system, which affected 55,000 customers during the coldest days of 2022.

Q. SHOULD THE COMMISSION DIRECT THE COMPANIES TO EXPLORE THE DISPATCH OPTIONS RECOMMENDED BY CAD WITNESS MEDINE?

A. No. Ms. Medine's recommendation is not supported by any analysis of the economics or the dispatch of the Companies' units with respect to their PJM energy market prices and ignores the negative impacts on customers. Furthermore, the Companies fully explained in great detail in direct testimony in this proceeding (and prior ENEC cases) the extensive and studied efforts they make to watch the market and maximize economic dispatch of the units.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

ATTACHMENT 5

Keith D. Fisher
Senior Counsel

200 Association Drive, Suite 201
Charleston, WV 25311
304.348.4154
kdfisher@aep.com

October 1, 2025

Via Electronic Filing
Karen Buckley, Executive Secretary
Public Service Commission of West Virginia
201 Brooks St.
Charleston, WV 25301

Re: Case No. 25-0450-E-GI
Appalachian Power Company and Wheeling Power Company
Proceeding regarding participation in the PJM Capacity Auction and continuation of Fixed Resource Requirement status in the PJM Interconnection, LLC wholesale power capacity market

RESPONSE OF APPALACHIAN POWER COMPANY AND WHEELING POWER COMPANY TO COMMISSION ORDER INITIATING GENERAL INVESTIGATION

On May 23, 2025, in the above-referenced matter, the Commission ordered Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo") (together, the "Companies") to provide the following information on or before October 1, 2025:

> IT IS FURTHER ORDERED that on or before October 1, 2025, Appalachian Power Company and Wheeling Power Company, jointly, shall file information to explain why they should maintain Fixed Resource Requirements status and how ratepayers would benefit or be harmed if the Companies transitioned to the Reliability Pricing Model status.
>
> IT IS FURTHER ORDERED that on or before October 1, 2025, Appalachian Power Company and Wheeling Power Company, jointly, shall make a filing that explains how the AEP bid-eligible MWs are assigned or allocated to them and provide: (i) the capacity obligations assigned to them for the last three PJM delivery years; (ii) the amount of PJM Installed Capacity (ICAP) and Unforced Capacity (UCAP) for each generating unit; (iii) an explanation of how the inter-AEP Company Agreement to which they are parties treats total capacity obligations and excess or deficiencies in APCo/WPCo capacity; and (iv) a copy of the current inter-AEP Company Agreement.

Pursuant to that Order, the Companies respond as follows to the Commission's questions:

1. Why should the Companies maintain Fixed Resource Requirement status and how would their ratepayers benefit or be harmed if the Companies transitioned to the Reliability Pricing Model?

ANSWER: The Fixed Resource Requirement (FRR) Alternative in PJM is an option that allows a Load Serving Entity (LSE) to meet its capacity obligation without participating in the Reliability Pricing Model (RPM) Base Residual Auction. Rather, the LSE demonstrates that it has secured sufficient capacity resources to serve its load. The FRR alternative benefits LSEs, like APCo and WPCo, by providing cost stability, resource mix flexibility, alignment with State policy, the ability to leverage owned generation, as well as netting of unit performance during Performance Assessment Interval (PAI) events. Transitioning to RPM would expose the Companies' customers to RPM price volatility, reduce the level of State control over future resource decisions versus direct self-supply via the FRR alternative, and increase exposure to financial penalty risks during PAIs.

2. How are AEP bid-eligible MWs assigned or allocated to the Companies?

ANSWER: As FRR load serving entities in PJM, the Companies have opted out of the capacity market and meet their resource adequacy requirements by self-supply. That said, if the Companies' FRR plan is approved before an auction, the Companies are allowed limited participation in the auction to the extent they have extra capacity length. The amount that AEP can sell is based on the individual and collective PJM obligations of the four participants in the Power Coordination Agreement.

3. What are the capacity obligations assigned to the Companies for the last three PJM delivery years?

ANSWER:

PJM Delivery Year	APCo FRR Obligation	WPCo FRR Obligation	Total
2022-2023	5,679.1 MW	699.8 MW	6,378.9 MW
2023-2024	5,762.4 MW	777.8 MW	6,540.2 MW
2024-2025	6,020.1 MW	793.0 MW	6,813.1 MW

4. What is the amount of PJM Installed Capacity (ICAP) and Unforced Capacity (UCAP) for each generating unit?

ANSWER: See "APCo/WPCo Confidential Attachment 1" provided herewith. The UCAP values are confidential and, therefore, have been redacted from the public version. An unredacted copy will be provided to the Commission under seal via hand delivery.

5. How does the inter-AEP Company Agreement to which the Companies are parties treat total capacity obligations and excess or deficiencies in APCo/WPCo capacity?

ANSWER: The respective PJM capacity position of each AEP Operating Company (OPCO) is determined as follows:

1. Resource Allocation - Ownership percentage for each PJM accredited resource is determined and the accredited MWs are allocated to the respective OPCO.
2. FRR Load Obligation Allocation - AEP Load Forecasting provides a detailed allocation of the AEP FRR Plan's load obligation disaggregated by OPCO.
3. Calculated Length for PCA - The respective OPCO positions are then calculated.
4. Total Sales Volume - Sales made via PJM's RPM Auctions and any intercompany transactions are allocated by net position amongst the OPCOs and Rockport 2, which as of December 7, 2022, could no longer participate in the AEP FRR plan.

Please see Section 7.5 Off System Transactions in the attached Power Coordination Agreement (PCA) for further details.

6. Please provide a copy of the current inter-AEP Company Agreement.

ANSWER: A copy of the Power Coordination Agreement (PCA) is provided herewith as "APCo/WPCo Attachment 2."

Respectfully submitted this 1st day of October 2025.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY

By counsel,

Keith D. Fisher (WV State Bar #11346)
American Electric Power Service Corp.
200 Association Drive, Suite 201
Charleston, WV 25311
(304) 348-4154
kdfisher@aep.com

		APCO PY2022		APCO PY2023		APCO PY2024	
Resource Name	Type	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP
AMOS 1	Coal	800.0		800.0		800.0	
AMOS 2	Coal	800.0		800.0		800.0	
AMOS 3	Coal	1,330.1		1,330.1		1,330.1	
CEREDO 1	Gas - CT	75.5		75.5		75.5	
CEREDO 2	Gas - CT	75.5		75.5		75.5	
CEREDO 3	Gas - CT	75.5		75.5		75.5	
CEREDO 4	Gas - CT	75.5		75.5		75.5	
CEREDO 5	Gas - CT	75.4		75.4		75.4	
CEREDO 6	Gas - CT	75.5		75.5		75.5	
CLIFTY CREEK 1 OVEC INT	Coal	30.4		30.4		30.4	
CLIFTY CREEK 2 OVEC INT	Coal	30.4		30.4		30.4	
CLIFTY CREEK 3 OVEC INT	Coal	30.4		30.4		30.4	
CLIFTY CREEK 4 OVEC INT	Coal	30.4		30.4		30.4	
CLIFTY CREEK 5 OVEC INT	Coal	30.4		30.4		30.4	
CLIFTY CREEK 6 OVEC INT	Coal	30.4		30.4		30.4	
CLINCH RIVER 1	Gas	225.0		225.0		225.0	
CLINCH RIVER 2	Gas	231.5		231.5		231.5	
BRUNSWICK CTY LF	Diesel / LF	-		-		-	
CLOYD MOUNTAIN LF	Diesel / LF	3.0		3.0		4.1	
HENRICO COUNTY LF	Diesel / LF	-		-		3.9	
KING-QUEEN LF	Diesel / LF	8.0		8.0		1.4	
CHARLES CITY LF	Diesel / LF	-		-		-	
AEPSCG AEP DR	Demand Response	70.4		44.2		41.2	
DRESDEN CT 1	Gas - CC	167.0		167.0		167.0	
DRESDEN CT 2	Gas - CC	167.0		167.0		167.0	
DRESDEN ST 1	Gas - CC	236.0		236.0		236.0	
KYGER CREEK 1 OVEC INT	Coal	30.1		30.1		30.1	
KYGER CREEK 2 OVEC INT	Coal	30.0		30.0		30.0	
KYGER CREEK 3 OVEC INT	Coal	30.0		30.0		30.0	
KYGER CREEK 4 OVEC INT	Coal	30.0		30.0		30.0	
KYGER CREEK 5 OVEC INT	Coal	30.0		30.0		30.0	
MOUNTAINEER 1	Coal	1,305.0		1,305.0		1,305.0	
BUCK-BYLLESBY	Hydro Intermittent	5.5		30.1		30.1	
CLAYTOR 1	Hydro Intermittent	18.8		19.5		19.5	
CLAYTOR 2	Hydro Intermittent	18.8		19.1		19.1	
CLAYTOR 3	Hydro Intermittent	18.8		21.1		21.1	
CLAYTOR 4	Hydro Intermittent	18.8		20.6		20.6	
LEESVILLE 1-2	Hydro Intermittent	49.0		49.8		49.8	
LONDON 1-3	Hydro Intermittent	6.5		17.8		17.8	
MARMET 1-3	Hydro Intermittent	5.8		17.3		17.3	
NIAGARA 1-2	Hydro Intermittent	0.6		2.4		2.4	
SUMMERSVILLE 1-2	Hydro Intermittent	80.0		80.0		80.0	
WINFIELD 1-3	Hydro Intermittent	9.9		22.5		22.5	
KERR DAM 1-7	Hydro NPS	3.6		3.6		3.6	
SMITH MOUNTAIN 1	8-hr Storage	65.0		65.0		65.0	
SMITH MOUNTAIN 2	8-hr Storage	175.0		175.0		175.0	
SMITH MOUNTAIN 3	8-hr Storage	105.0		105.0		105.0	
SMITH MOUNTAIN 4	8-hr Storage	175.0		175.0		175.0	
SMITH MOUNTAIN 5	8-hr Storage	65.0		65.0		65.0	
BLUFF POINT WF	Onshore Wind	119.7		120.0		120.0	
CAMP GROVE WF	Onshore Wind	75.0		75.0		75.0	
FOWLER RIDGE 3 WF	Onshore Wind	99.0		99.0		99.0	
FIELD MOUNTAIN WF	Onshore Wind	100.5		100.0		100.0	
GRAND RIDGE 2 WF	Onshore Wind	51.0		54.4		54.4	
GRAND RIDGE 3 WF	Onshore Wind	49.5		52.8		52.8	
Totals		**7,444.2**		**7,492.2**		**7,487.6**	

		WPCO PY2022		WPCO PY2023		WPCO PY2024	
Resource Name	**Type**	**ICAP**	**UCAP**	**ICAP**	**UCAP**	**ICAP**	**UCAP**
PLEASANTS 1-2	Coal			-	-	90.9	[redacted]
MITCHELL 1 AEP	Coal	385.1	[redacted]	385.1	[redacted]	385.1	
MITCHELL 2 AEP	Coal	395.1		395.1		395.1	
Totals		**780.2**		**780.2**		**871.1**	

Sheet No. 1

RATE SCHEDULE No. 300

POWER COORDINATION AGREEMENT

among

APPALACHIAN POWER COMPANY,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY POWER COMPANY,
WHEELING POWER COMPANY

and

AMERICAN ELECTRIC POWER SERVICE CORPORATION

as Agent

Tariff Submitter: **Appalachian Power Company**
FERC Program Name: **FERC FPA Electric Tariff**
Tariff Title: **APCo Rate Schedules and Service Agreements Tariffs**
Tariff Proposed Effective Date**: 06/01/2015**
Tariff Record Title: **Power Coordination Agreement**
Option Code: **A**
Record Content Description: **Rate Schedule No. 300**

POWER COORDINATION AGREEMENT

THIS AGREEMENT is made and entered into as of this __ day of _____, 2015, by and among Appalachian Power Company ("APCo"), Indiana Michigan Power Company ("I&M"), Kentucky Power Company ("KPCo"), Wheeling Power Company ("WPCo") and American Electric Power Service Corporation ("AEPSC") as agent ("Agent") to APCo, I&M. KPCo and WPCo.

RECITALS:

WHEREAS, APCo, I&M, KPCo and WPCo (collectively the "Operating Companies" or individually "Operating Company") own and operate electric generation, transmission and distribution facilities with which they are engaged in the business of generating, transmitting and selling electric power to the general public and to other electric utilities;

WHEREAS, the Operating Companies' electric facilities are now and have been for many years interconnected through their respective transmission facilities and transmission facilities of third parties at a number of points;

WHEREAS, APCo, I&M, KPCo and WPCo provide power to serve retail and wholesale customers in Indiana, Kentucky, Michigan, Tennessee, Virginia and West Virginia;

WHEREAS, APCo, I&M, KPCo and WPCo believe that they can continue to achieve efficiencies and economic benefits through (a) participation in the organized power markets of a regional transmission organization and (b) allocation of off-system sales and purchases with other parties on bases that fairly assign or allocate the costs and benefits of these transactions;

WHEREAS, the achievement of the foregoing will be facilitated by the performance of certain services by an Agent;

WHEREAS, AEPSC is the service company affiliate of APCo, I&M, KPCo and WPCo and as such performs a variety of services on their behalf in accordance with applicable rules and regulations of the Federal Energy Regulatory Commission ("Commission"); and

WHEREAS, AEPSC is willing to serve as Agent to APCo, I&M, KPCo and WPCo under this Agreement.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein set forth, the Parties mutually agree as follows:

ARTICLE I
DEFINITIONS

1.1 Agreement means this Power Coordination Agreement among APCo, I&M, KPCo, WPCo and Agent, including all Service Schedules and attachments hereto.

1.2 Capacity Auction means auctions implemented pursuant to a Capacity Market, and may include, but is not necessarily limited to, the Base Residual Auction and other incremental auctions conducted in accordance with the PJM Interconnection, LLC ("PJM") Reliability Pricing Model market rules.

1.3 Capacity Market means any market of an applicable regional transmission organization under which the Operating Companies satisfy their capacity obligations as load serving entities, which would include, for example, the PJM capacity market as described in the PJM Reliability Assurance Agreement ("RAA") and Attachment DD of the PJM Open Access Transmission Tariff ("PJM OATT").

1.4 Dedicated Wholesale Customer means a wholesale customer whose load is served by an Operating Company that has undertaken, by contract, an obligation to serve that customer's partial or full requirements load and to acquire power supply resources and other resources necessary to meet those requirements.

1.5 Generation Hedge Transactions means Off-System Transactions entered into for the purpose of hedging the output of the generation assets of one or more of the Operating Companies.

1.6 Industry Standards means all applicable national and regional electric reliability council and regional transmission organization principles, guides, criteria, standards and practices.

1.7 Internal Load means all sales of power, plus associated line losses, by an Operating Company to its Retail Customers and Dedicated Wholesale Customers. As distinguished from Off-System Sales, Internal Load is principally characterized by the Operating Company assuming the load obligation as its own power commitment.

1.8 Off-System Sales means all wholesale power sales by an Operating Company other than sales to the Retail Customers and Dedicated Wholesale Customers that comprise the Operating Company's Internal Load. Sales of wholesale power by an Operating Company to another Operating Company are not governed by this Agreement, and will not be deemed Off-System Sales under this Agreement.

1.9 Off-System Purchases means wholesale power purchases by an Operating Company or Operating Companies for any of the following reasons: (a) to reduce power supply costs, (b) to serve load requirements, (c) to provide reliability of supply, (d) to satisfy state specific requirements or goals or (e) to engage in Off-System Sales. Purchases of wholesale power by an Operating Company from another Operating Company are not governed by this Agreement, and will not be deemed Off-System Purchases under this Agreement.

1.10 Off-System Transactions means Off-System Sales, Off-System Purchases and any other types of power-related wholesale transactions, whether physical or financial, on behalf of an Operating Company or Operating Companies, excluding sales to Internal Load customers.

1.11 Operating Committee means the administrative body established pursuant to Article VI for the purposes specified within this Agreement.

1.12 Party means each of APCo, I&M, KPCo, WPCo and Agent, individually, and **Parties** means APCo, I&M, KPCo, WPCo and Agent, collectively.

1.13 Retail Customer means a retail power customer on whose behalf an Operating Company has undertaken an obligation to obtain power supply resources in order to supply electricity to reliably meet the electric needs of that customer.

1.14 Service Schedules means the Service Schedules attached to this Agreement, as they may be amended from time to time, and those that later may be agreed to by the Parties and made part of a modified Agreement.

1.15 Spot Market means the day ahead, real time (balancing) or similar short-term energy market(s) operated by the applicable regional transmission organization(s), typically characterized by energy that is selected and delivered on an hourly, or more frequent, basis during that same day or the next calendar day.

1.16 System Emergency means a condition which, if not promptly corrected, threatens to cause imminent harm to persons or property, including the equipment of a Party or a Third Party, or threatens the reliability of electric service provided by an Operating Company to Retail Customers or Dedicated Wholesale Customers.

1.17 Third Party or Third Parties means any entity or entities that are not a Party or Parties.

1.18 Trading Transactions means Off-System Transactions that are not Generation Hedge Transactions or otherwise sourced or hedged from, dedicated to, or associated with the generation assets or Internal Load of the Operating Companies.

ARTICLE II
TERM OF AGREEMENT

2.1 Term and Withdrawal. Subject to Commission approval or acceptance for filing, this Agreement shall take effect on June 1, 2015, or such other date permitted by the Commission, and shall continue in full force and effect until (a) terminated by mutual agreement or (b) upon no less than twelve (12) months' written notice by one Party to each of the other Parties, after which time the notifying Party will be withdrawn from the Agreement and the Agreement will continue in full force and effect for the remaining Parties except for such modifications necessary to remove the withdrawn Party.

ARTICLE III
[INTENTIONALLY OMITTED]

ARTICLE IV
SCOPE AND RELATIONSHIP TO OTHER AGREEMENTS AND SERVICES

4.1 Scope. This Agreement is not intended to preclude the Parties from entering into other arrangements between or among themselves or with Third Parties. This Agreement is intended to operate in addition to, not in lieu of, power market transactions and settlements that occur between each Operating Company, or the Operating Companies collectively, and any applicable regional transmission organizations.

4.2 Transmission. This Agreement is intended to apply to the coordination of the power supply resources of, and loads served by, the Operating Companies. It is not intended to

apply to the coordination of transmission facilities owned or operated by the Operating Companies.

ARTICLE V
AGENT

5.1 Agent. The Agent will perform the activities and duties specified by this Agreement and any other activities or duties pertaining to this Agreement that may be requested from time to time by one or more Operating Companies, subject to the receipt of any necessary regulatory approvals. The Operating Companies delegate to AEPSC, as the Agent, and AEPSC hereby accepts responsibility and authority for the duties specified in this Agreement and shall perform each of those duties under the direction of the Operating Companies. With the prior written consent of the Operating Companies, AEPSC may delegate all or a part of its responsibilities under this Agreement to another entity.

ARTICLE VI
COMPOSITION AND DUTIES OF THE OPERATING COMMITTEE

6.1 Operating Committee. By written notice to the other Parties, each Party shall name one representative ("Representative") to act for it in matters pertaining to this Agreement and its implementation. A Party may change its Representative at any time by written notice to the other Parties. The Representatives of the respective Parties shall comprise the Operating Committee. The Agent's Representative shall act as the chairman of the Operating Committee ("Chairman"). All decisions of the Operating Committee shall be by a simple majority vote of the Representatives. There shall be only five voting representatives on the Operating Committee. No Party may delegate its vote to another entity.

6.2 Meeting Dates. The Operating Committee shall hold meetings at such times, means, and places as the members shall determine. Minutes of each Operating Committee meeting shall be prepared and maintained.

6.3 Duties. The Operating Committee shall have the duties listed below:

(a) reviewing and providing direction concerning the equitable sharing of costs and benefits under this Agreement among the Operating Companies;

(b) administering this Agreement and proposing amendments hereto, including such amendments that are proposed in response to a change in regulatory requirements applicable to one or more of the Operating Companies or changes concerning an applicable regional transmission organization, provided that any amendments will be subject to Section 13.2; and

(c) reviewing and, if necessary, proposing changes to the duties and responsibilities of the Agent, subject to Section 5.1.

In the event that an action of the Operating Committee results in a change to the settlement process(es) among the Operating Companies, such modified settlement will normally occur on a prospective basis only, however, this may include past billing periods back to the beginning of the first full billing month preceding the date of action of the Operating Committee. Such modifications will be subject to the terms of Article IX as applicable.

ARTICLE VII
OPERATING COMPANY PLANNING AND OPERATIONS

7.1 Operating Company and System Planning. Each Operating Company will be individually responsible for its own capacity planning. Consistent with the requirements of PJM or the applicable regional transmission or reliability organization, each Operating Company will be responsible for maintaining an adequate level of power supply resources to meet its own

Internal Load requirements for capacity and energy, including any required reserve margins, and shall bear all of the resulting costs. The Agent shall assess the adequacy of the power supply resources of the Operating Companies and make recommendations to each Operating Company regarding (1) the need for additional power supply resources and (2) whether each Operating Company has power supply resources in excess of its needs (short-term or long-term) that could be made available to the other Operating Companies or Third Parties either through separate contracts or through the power markets of the applicable regional transmission organization. The actual addition or disposition of power supply resources will be conditioned on compliance with all applicable state and other regulatory requirements and requirements of the applicable regional transmission organization.

7.2 Generation Resource Outage Planning. The Agent, on behalf of the Operating Companies, will coordinate the scheduling of planned generation resource outages in order to support reliability and manage costs.

7.3 Generation Resource Dispatch. The generation resources of each of the Operating Companies will be individually dispatched by the Agent in accordance with the direction of the applicable regional transmission organization.

7.4 Regional Transmission Organization Transactions. The Agent will administer the participation of the Operating Companies in the power markets of the applicable regional transmission organization. Each Operating Company shall be individually responsible for charges it incurs and credits it receives due to its participation in the power markets of a regional transmission organization. Such costs and revenues will be assigned or allocated directly by the applicable regional transmission organization or its agent where practical. The Operating Companies may collectively participate from time to time in specific markets of the regional

transmission organization or to meet certain regional transmission or reliability organization requirements, in which case the allocation of resulting revenues and/or costs, if any, will be performed as specified herein. The election of whether each Operating Company's load and generation resources will participate in the Capacity Market of PJM through the Reliability Pricing Model auctions or through the Fixed Resource Requirement alternative, either collectively or individually, for any planning year is not governed by this Agreement.

7.5 Off System Transactions. The Agent will engage in Off-System Transactions on behalf of or at the direction of the Operating Companies and will assign or allocate the costs and revenues of Off-System Transactions to the Operating Companies in the manner specified below.

7.5.1 Capacity Purchases and Sales with Third Parties. Except as described in Section 7.5.2 related to the PJM Capacity Auctions: (1) Off-System Transactions of capacity undertaken for an individual Operating Company will be directly assigned to that Operating Company; (2) Off-System Purchases of capacity undertaken for more than one Operating Company will be allocated among those Operating Companies ratably in proportion to the total capacity needed by each Operating Company minus each Operating Company's total capacity resources; and (3) Off-System Sales of capacity undertaken for more than one Operating Company will be allocated among those Operating Companies ratably in proportion to the total capacity resources of each Operating Company minus the total capacity obligation of each Operating Company (including any holdback required by the applicable regional transmission organization).

7.5.2 Capacity Purchases and Sales in the PJM Capacity Auctions And Related Issues. When an Operating Company participates individually in the Reliability Pricing Model or the Fixed Resource Requirement alternative, Off-System Transactions

of capacity related to a PJM Capacity Auction will be directly assigned to the specific Operating Company based on the results of such auctions.

When two or more Operating Companies collectively participate in the Fixed Resource Requirement alternative, any Off-System Transactions of capacity related to a PJM Capacity Auction will be allocated to each participating Operating Company ratably in proportion to the total capacity resources of each Operating Company minus the total capacity obligation of each Operating Company (including any holdback required by PJM) for the applicable planning year(s), and Service Schedule A will apply to delivery year and post-delivery year obligations of the participating Operating Companies associated with the Fixed Resource Requirement alternative.

7.5.3 Directly Assigned Energy Purchases and Sales with Third Parties. Off-System Transactions of energy will be directly assigned to the applicable Operating Company. Costs and revenues associated with each Operating Company's Off-System Sales of energy and Internal Load energy purchases from the applicable regional transmission organization in the Spot Market, including the purchase of any energy deficits or sales of any energy surpluses, will be directly assigned to that Operating Company.

7.5.4 Generation Hedge Transactions and Trading Transactions. Revenues and costs associated with Generation Hedge Transactions, including revenues and costs associated with the settlement of Generation Hedge Transactions in the Spot Market or other markets of the applicable regional transmission organization, will be allocated among the Operating Companies by the Agent as specified under Service Schedule B.

Revenues and costs associated with Trading Transactions, including revenues and costs associated with the settlement of Trading Transactions in the Spot Market or other markets of the applicable regional transmission organization, will be allocated among the Operating Companies by the Agent as specified under Service Schedule C.

7.6 Emergency Response. In the event of a System Emergency, no adverse distinction shall be made between the customers of any of the Operating Companies. Each Operating Company shall, under the direction of the applicable regional transmission organization, make its power supply resources available in response to a System Emergency. Notwithstanding the foregoing, it is understood that transmission constraints or other factors may limit the ability of an Operating Company to respond to a System Emergency.

ARTICLE VIII
ASSIGNMENT OF COSTS AND BENEFITS OF COORDINATED OPERATIONS

8.1 Service Schedules. The costs and revenues associated with coordinated operations as described in Article VII shall be distributed among the Operating Companies in the manner provided in the Service Schedules utilizing the billing procedures described in Article IX. It is understood and agreed that all such Service Schedules are intended to establish an equitable sharing of costs and/or benefits among the Operating Companies, and that circumstances may, from time to time, require a reassessment of the relative costs and benefits of this Agreement, or of the methods used to apportion costs and benefits under the Service Schedules. Upon a proposal of the Operating Committee, any of the Service Schedules may be amended as of any date agreed to by the Operating Committee by majority vote, subject to Section 13.2.

ARTICLE IX
BILLING PROCEDURES

9.1 Records. The Agent shall maintain such records as may be necessary to determine the assignment of costs and revenues of coordinated operations pursuant to this Agreement. Such records shall be made available to the Parties upon request for a period not to exceed three (3) years.

9.2 Monthly Net Billing Statements. As promptly as practicable after the end of each calendar month, the Agent shall prepare a statement setting forth the monthly summary of costs and revenues allocated or assigned to the Operating Companies in sufficient detail as may be needed for settlements under the provisions of this Agreement. As required, the Agent may provide such statements on an estimated basis and then adjust those statements for actual results.

9.3 Billings and Payments. The Agent shall be responsible for all billing between the Operating Companies and other entities with which they engage in Off-System Transactions pursuant to this Agreement. Payments among the Operating Companies, if any, shall be made by remittance of the net amount billed or by making appropriate accounting entries on the books of the Parties. The entire amount shall be paid when due.

9.4 Taxes. Should any federal, state, or local tax, surcharge or similar assessment, in addition to those that may now exist, be levied upon the electric capacity, energy, or services to be provided in connection with this Agreement, or upon the provider of service as measured by the electric capacity, energy, or services, or the revenue there from, such additional amount shall be included in the net billing described in Section 9.3.

9.5 Undelivered and Unpaid Monthly Billing Statements. Within one (1) year from the date on which a billing statement should have been delivered, if a Party's records reveal that the bill was not delivered, then the Agent shall deliver to the appropriate Party a bill within

one (1) month of this determination. Any amounts collected or reimbursed due to such delay shall not include interest.

9.6 Billing Errors and Disputes. If a Party discovers a billing error pertaining to a prior billing for reasons including, but not limited to, missing or erroneous data or calculations, including those caused by meter, computer or human error, a correction adjustment will be calculated through the second full month preceding discovery of the error. The Parties shall have the right to dispute the accuracy of any bill or payment for a period not to exceed two months from the date on which the bill or, if applicable, the corrected bill was initially delivered. Following this two-month period, the right to dispute a bill is permanently waived for any and all reasons including but not limited to, (a) errors, (b) omissions, (c) Agent's actions, and (d) the Operating Committee's decisions, Agreement interpretations and direction in the administration of the Agreement. Any amounts collected or reimbursed due to such disputes shall not include interest.

ARTICLE X
FORCE MAJEURE

10.1 Events Excusing Performance. No Party shall be liable to another Party for or on account of any loss, damage, injury, or expense resulting from or arising out of a delay or failure to perform, either in whole or in part, any of the agreements, covenants, or obligations made by or imposed upon the Parties by this Agreement, by reason of or through strike, work stoppage of labor, failure of contractors or suppliers of materials (including fuel, consumables or other goods and services), failure of equipment, environmental restrictions, riot, fire, flood, ice, invasion, civil war, commotion, insurrection, military or usurped power, order of any court or regulatory agency granted in any *bona fide* legal proceedings or action, or of any civil or military

authority either *de facto* or *de jure,* explosion, Act of God or the public enemies, or any other cause reasonably beyond its control and not attributable to its neglect. A Party experiencing such a delay or failure to perform shall use due diligence to remove the cause or causes thereof; however, no Party shall be required to add to, modify or upgrade any facilities, or to settle a strike or labor dispute except when, according to its own best judgment, such action is advisable.

ARTICLE XI
DELIVERY POINTS

11.1 Delivery Points. All electric energy delivered under this Agreement shall be of the character commonly known as three-phase sixty-cycle energy, and shall be delivered at the various points where the transmission systems of the Operating Companies are interconnected, either directly or through transmission facilities of third parties, at the nominal unregulated voltage designated for such points, and at such other points and voltages as may be determined and agreed upon by the Operating Companies.

ARTICLE XII
GENERAL

12.1 Adherence to Industry Standards. The Parties agree to make their best efforts to conform to Industry Standards as they affect the implementation of and conduct pertaining to this Agreement.

12.2 No Third Party Beneficiaries. This Agreement does not create rights of any character whatsoever in favor of any person, corporation, association, entity or power supplier, other than the Parties, and the obligations herein assumed by the Parties are solely for the use and benefit of the Parties. Nothing in this Agreement shall be construed as permitting or vesting, or attempting to permit or vest, in any person, corporation, association, entity or power supplier,

other than the Parties, any rights hereunder or in any of the resources or facilities owned or controlled by the Parties or the use thereof.

12.3 Waivers. Any waiver at any time by a Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this Agreement, shall not be deemed a waiver of such right.

12.4 Successors and Assigns. This Agreement shall inure to the benefit of and be binding upon the Parties only, and their respective successors and assigns, and shall not be assignable by any Party without the written consent of the other Parties except to a successor in the operation of its properties by reason of a reorganization to comply with state or federal restructuring requirements, or a merger, consolidation, sale or foreclosure whereby substantially all such properties are acquired by or merged with those of such a successor.

12.5 Liability and Indemnification. SUBJECT TO ANY APPLICABLE STATE OR FEDERAL LAW THAT MAY SPECIFICALLY RESTRICT LIMITATIONS ON LIABILITY, EACH PARTY (AN "INDEMNIFYING PARTY") SHALL RELEASE, INDEMNIFY, AND HOLD HARMLESS THE OTHER PARTIES (EACH AN "INDEMNIFIED PARTY"), THEIR DIRECTORS, OFFICERS AND EMPLOYEES FROM AND AGAINST ANY AND ALL LIABILITY FOR LOSS, DAMAGE OR EXPENSE (1) ALLEGED TO ARISE FROM, OR BE INCIDENTAL TO, INJURY TO PERSONS AND/OR DAMAGE TO PROPERTY IN CONNECTION WITH THE INDEMNIFYING PARTY'S FACILITIES OR THE PRODUCTION OR TRANSMISSION OF ELECTRIC ENERGY BY OR THROUGH THE INDEMNIFYING PARTY'S FACILITIES OR (2) RELATED TO PERFORMANCE OR NON-

PERFORMANCE OF THIS AGREEMENT OR (3) RELATED TO ANY NEGLIGENCE ARISING UNDER THIS AGREEMENT. IN NO EVENT SHALL ANY PARTY BE LIABLE TO ANOTHER PARTY FOR ANY INDIRECT, SPECIAL, INCIDENTAL, OR CONSEQUENTIAL DAMAGES WITH RESPECT TO ANY CLAIM ARISING OUT OF THIS AGREEMENT.

12.6 Headings. The descriptive headings of the Articles, Sections and Service Schedules of this Agreement are used for convenience only, and shall not modify or restrict any of the terms and provisions thereof.

12.7 Notice. Any notice or demand for performance required or permitted under any of the provisions of this Agreement shall be deemed to have been given on the date such notice, in writing, is deposited in the U.S. mail, postage prepaid, certified or registered mail, addressed to the Parties at their principal place of business at 1 Riverside Plaza, Columbus, Ohio 43215, or in such other form or to such other address as the Parties may stipulate.

12.8 Interpretation. In this Agreement: (a) unless otherwise specified, references to any Article or Section are references to such Article or Section of this Agreement; (b) the singular includes the plural and the plural includes the singular; (c) unless otherwise specified, each reference to a requirement of any governmental entity or regional transmission organization includes all provisions amending, modifying, supplementing or replacing such governmental entity or regional transmission organization from time to time; (d) the words "including," "includes" and "include" shall be deemed to be followed by the words "without limitation"; (e) unless otherwise specified, each reference to any tariff or agreement includes all amendments, modifications, supplements, and restatements made to such tariff or agreement from time to time which are not prohibited by this Agreement; (f) the descriptive headings of the various Articles

and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict the terms and provisions thereof; and (g) "herein," "hereof," "hereto" and "hereunder" and similar terms refer to this Agreement as a whole.

ARTICLE XIII
REGULATORY APPROVAL

13.1 Regulatory Authorization. This Agreement is subject to and conditioned upon its approval or acceptance for filing without material condition or modification by the Commission. In the event that this Agreement is not so approved or accepted for filing in its entirety or without conditions or modifications unacceptable to any Party, or the Commission subsequently modifies this Agreement upon complaint or upon its own initiative (as provided for in Section 13.2), any Party may, irrespective of the notice provisions in Section 2.1, withdraw from this Agreement by giving thirty (30) days' advance written notice to the other Parties.

13.2 Changes. It is contemplated by the Parties that it may be appropriate from time to time to change, amend, modify, or supplement this Agreement, including the Service Schedules and any other attachments that may be made a part of this Agreement, to reflect changes in operating practices or costs of operations or for other reasons. Any such changes to this Agreement shall be in writing executed by the Parties and subject to approval or acceptance for filing by the Commission.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

APPALACHIAN POWER COMPANY

By: Charles Patton

Title: President & COO

INDIANA MICHIGAN POWER COMPANY

By: _____

Title: _____

KENTUCKY POWER COMPANY

By: _____

Title: _____

WHEELING POWER COMPANY

By: Charles Patton

Title: President & COO

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: _____

Title: _____

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

APPALACHIAN POWER COMPANY

By: _____

Title: _____

INDIANA MICHIGAN POWER COMPANY

By: _____

Title: President + COO

KENTUCKY POWER COMPANY

By: _____

Title: _____

WHEELING POWER COMPANY

By: _____

Title: _____

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: _____

Title: _____

Sheet No. 19

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

APPALACHIAN POWER COMPANY

By: _____

Title: _____

INDIANA MICHIGAN POWER COMPANY

By: _____

Title: _____

KENTUCKY POWER COMPANY

By: Greg B Pauley

Title: President & COO

WHEELING POWER COMPANY

By: _____

Title: _____

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: _____

Title: _____

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

APPALACHIAN POWER COMPANY

By: _____

Title: _____

INDIANA MICHIGAN POWER COMPANY

By: _____

Title: _____

KENTUCKY POWER COMPANY

By: _____

Title: _____

WHEELING POWER COMPANY

By: _____

Title: _____

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: Roland E. Moenich

Title: SVP Regulatory Svcs.

SERVICE SCHEDULE A
COLLECTIVE PARTICIPATION IN THE
FIXED RESOURCE REQUIREMENT ALTERNATIVE

A1– Duration. This Service Schedule A shall become effective and binding when the Agreement of which it is a part becomes effective, and shall continue in full force and effect throughout the duration of the Agreement unless terminated or suspended.

A2 – Availability of Service. This Service Schedule A governs the administration and settlement of capacity during such times that multiple Operating Companies are participating, on a collective basis, in the Fixed Resource Requirement alternative.

A3 – Delivery Year and Post-Delivery Year Settlement. During a given PJM planning year (i.e., the delivery year), the Agent will manage the capacity resources needed to meet the combined Operating Companies' capacity obligations and commitments to PJM.

If capacity resource performance charges are assessed by PJM for a given delivery year, the total net charge will be allocated among the Operating Companies ratably in proportion to each Operating Company's contribution to the total charge, taking into account the effect of collective participation of the Operating Companies in the Fixed Resource Requirement alternative. Each Operating Company's contribution to the total net charge will be determined by the Agent by computing a total MW position for each Operating Company by subtracting its total capacity obligation in MWs from its total capacity resources in MWs. This result will be further adjusted by adding or subtracting as applicable the net total MWs of actual under-performance or over-performance of each Operating Company's capacity resources during the delivery year as computed by PJM. Any Operating Company with a resulting net short MW position, meaning that its capacity obligation MWs are greater than its capacity resource MWs including any MWs of over-performance or under-performance, will be allocated a share of the

total net performance charge from PJM based on the Operating Company's net short MW position. Any performance charge not allocated as set forth above will be directly assigned to the Operating Company that caused the performance charge.

SERVICE SCHEDULE B
GENERATION HEDGE TRANSACTIONS

B1 – Duration. This Service Schedule B shall become effective and binding when the Agreement of which it is a part becomes effective, and shall continue in full force and effect throughout the duration of the Agreement unless terminated or suspended.

B2 – Service. This Service Schedule B governs energy-related Off-System Transactions made pursuant to Section 7.5.4 of the Agreement that are associated with Generation Hedge Transactions as defined in Section 1.5. The total monthly net costs and revenues from the settlement of Generation Hedge Transactions will be allocated among the Operating Companies ratably in proportion to the total of each Operating Company's surplus MWhs for the month, as determined by the Agent. Surplus MWhs will be computed as the total of all MWs in hours in which an Operating Company's MW output of its generation assets and energy purchases exceeded that Operating Company's Internal Load.

If the above allocation would result in any Operating Company being allocated revenues or costs associated with more than one hundred and fifteen percent (115%) of its monthly surplus MWhs as computed above, such excess(es) above that amount will be allocated to all of the Operating Companies ratably in proportion to the sum of each Operating Company's hourly MW output of its generation assets for the month.

SERVICE SCHEDULE C
TRADING TRANSACTIONS

C1 – Duration. This Service Schedule C shall become effective and binding when the Agreement of which it is a part becomes effective, and shall continue in full force and effect throughout the duration of the Agreement unless terminated or suspended.

C2 – Service. This Service Schedule C governs the financial allocation and settlement of Off-System Transactions made pursuant to Section 7.5.4 of the Agreement that are associated with Trading Transactions as defined in Section 1.18. All Trading Transactions settled for a given month will be allocated among the Operating Companies ratably in proportion to each Operating Company's total common shareholder equity balance. The total common shareholder equity balance for each Operating Company as of the end of the previous calendar year will be as stated in the FERC Form 1, currently page 112 (Total Proprietary Capital). These balances will then be applied to allocate settled Trading Transactions among the Operating Companies during the subsequent twelve-month period beginning June 1 and ending May 31.

ATTACHMENT 6

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF WEST VIRGINIA
AT CHARLESTON

BRUCE PERRONE, ROSANNA LONG,
and SIERRA CLUB,

Plaintiffs,

v. CIVIL ACTION No. 2:24-cv-00434

CHAIRMAN CHARLOTTE R. LANE,
COMMISSIONER RENEE A. LARRICK,
and COMMISSIONER WILLIAM B. RANEY,
in their official capacities,

Defendants,

and,

APPALACHIAN POWER COMPANY and,
WHEELING POWER COMPANY,

Defendant-Intervenors.

ORDER & CONSENT DECREE

I. RECITALS

WHEREAS, Plaintiffs filed this action on August 20, 2024;

WHEREAS, the Parties agree to resolve this matter through the entrance of this Consent Decree;

WHEREAS, the Parties recognize, and the Court by entering this Consent Decree finds, that the Consent Decree has been negotiated by the Parties in good faith and will avoid further litigation between the Parties, and that this Consent Decree is fair, reasonable, and in the public interest;

NOW, THREFORE, upon the consent of the parties hereto, **IT IS HEREBY**

ORDERED, ADJUDGED AND DECREED[1] as follows:

II. JURISDICTION AND VENUE

1. For the purposes of this Consent Decree, the Parties stipulate that the Court has jurisdiction over the subject matter of this action pursuant to 28 U.S.C. § 1331 and personal jurisdiction over the Parties.

2. Venue is proper in the Southern District of West Virginia, pursuant to 28 U.S.C. § 1391(b)(2) because a substantial part of the events giving rise to this action occurred in Charleston, West Virginia, and within the Southern District of West Virginia.

III. APPLICABILITY

3. Upon the Effective Date, the provisions of this Consent Decree shall apply to and be binding upon the Parties and their successors and assigns.

4. Commission Defendants shall provide a copy of this Consent Decree to all officers, employees, and agents whose duties include direct responsibility for compliance with any provision of this Consent Decree, as well as to any contractor retained to perform work required under this Consent Decree.

IV. DEFINITIONS

5. Whenever the terms set forth below are used in this Consent Decree, the following definitions shall apply:

a. "Commission" shall mean the Public Service Commission of West Virginia;

b. "Commission Defendants" shall mean Chairman Charlotte R. Lane, Commissioner Renee A. Larrick, and Commissioner William B. Raney, in their official capacities;

c. "Companies" shall mean Appalachian Power Company and Wheeling Power

[1] The parties' Joint Motion for Approval and Entry of Proposed Consent Decree is **GRANTED**. (ECF No. 54.)

Company;

d. "Complaint" shall mean the Complaint filed by Plaintiffs in this action on August 20, 2024;

e. "Consent Decree" shall mean this document;

f. "Defendant-Intervenors" shall mean the Companies;

g. "Effective Date" shall have the definition provided in Section VIII;

h. "Paragraph" shall mean a portion of this Consent Decree identifiable by an Arabic numeral;

i. "Parties" shall mean Plaintiffs, Commission Defendants, and Defendant-Intervenors collectively;

j. "Plaintiffs" shall mean Bruce Perrone, Rosanna Long, and Sierra Club;

k. "Section" shall mean any portion of this Consent Decree identified by a Roman numeral;

V. AGREEMENTS OF THE PARTIES

6. Notwithstanding the Parties' disagreements regarding the Commission Defendant's past orders at issue in the Complaint, the Parties agree, for the purposes of this Consent Decree, that the Commission Defendants, in their official capacities, have not in their orders issued prior to the date of this Consent Decree—including, but not limited to, its orders issued in the Companies' 2021, 2022, and 2023 Expanded Net Energy Cost ("ENEC") cases—ordered or required the Companies to run their coal-fired power plants at a 69 percent capacity factor or other minimum capacity factor when doing so is uneconomic.

7. It is further agreed that the Commission Defendants have not and will not, in their official capacities, interpret a 69 percent capacity factor as setting a minimum operational threshold but may evaluate the capacity factors of the coal-fired generation plants of the

Companies as part of a wholistic evaluation of whether such plants are being reasonably and prudently operated.

8. If the Commission Defendants, in their official capacities, issue an order in the future that Plaintiffs claim is inconsistent with this Agreement in Section V, Plaintiffs may file a complaint, motion, or any appropriate administrative pleading, such as a petition for reconsideration, challenging that order (subject to all defenses, procedural and substantive, to such a challenge), notwithstanding any other provisions of this Consent Decree.

VI. EFFECT OF SETTLEMENT AND RESERVATION OF RIGHTS

9. This Consent Decree represents a full and final settlement among the Parties.

10. This Consent Decree resolves and discharges, and Plaintiffs release and waive, any and all civil claims, causes of action, demands, actions, and/or rights of action that Plaintiffs brought in the Complaint against Commission Defendants for alleged violations of federal law.

11. This Consent Decree shall not be taken as an admission of any wrongdoing or illegal action by the Commission Defendants or any of the other Parties.

12. This Consent Decree shall not be interpreted as an admission by any of the Parties that positions taken during this action were improper, frivolous, or without merit.

VII. COSTS

13. The Parties shall bear their own costs of this civil action, including attorneys' fees.

VIII. NOTICES

14. Unless otherwise specified herein, whenever notifications, submissions, reports, or communications are required by the Consent Decree, they shall be made in writing and addressed as follows:

a. To Plaintiffs:

By mail to:
Amanda Demmerle
Appalachian Mountain Advocates, Inc.
P.O. Box 1157
Charleston, WV 25331

And by email to:
ademmerle@appalmad.org

b. To Commission Defendants:

Public Service Commission of West Virginia
Office of the General Counsel
201 Brooks Street
Charleston, WV 25301

c. To the Companies:

Appalachian Power Company
Wheeling Power Company
200 Association Drive
Charleston, WV 25311

IX. EFFECTIVE DATE

15. The Effective Date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court or a motion to enter this Consent Decree is granted, whichever occurs first, as recorded on the Court's docket.

X. RETENTION OF JURISDICTION

16. The Court shall retain jurisdiction over this action until termination of this Consent Decree, for the purpose of resolving disputes arising under this Consent Decree, enforcing the terms of this Consent Decree, or entering orders modifying this Consent Decree or effectuating or enforcing compliance with the terms of this Consent Decree.

17. Except as provided specifically herein, the Parties reserve all legal and equitable rights and defenses available to them to enforce or defend against enforcement of the provisions

of this Consent Decree. Before a Party invokes the Court's jurisdiction to resolve a dispute among the Parties, the Party shall send a written notice to the other Party outlining the nature of the dispute and requesting informal negotiations among the Parties to resolve the matter. If the Parties are unable to resolve the matter within fifteen (15) days from the date of the notice (or within an additional period of time agreed to by the Parties), the noticing Party shall provide the other Party with a subsequent written notice giving an opportunity to remedy such asserted breach within a reasonable time period (no less than fifteen (15) days) of receiving the notice. If the asserted breach is not cured within the applicable time period, any Party may seek relief from the Court.

XI. MODIFICATION

18. Except as specifically provided herein, the terms of this Consent Decree, including the attached appendices, may be modified only by a subsequent written agreement signed by the Parties. Where the modification constitutes a material change to this Decree, it shall be effective only upon approval by the Court.

XII. TERMINATION

19. This Consent Decree shall automatically terminate at the time that none of the Commission Defendants remain on the Commission.

XIII. LODGING AND ENTRY OF DECREE

20. The Parties agree to cooperate in good faith in order to obtain the Court's review and entry of this consent Decree.

XIV. SIGNATORIES/SERVICE

21. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

22. The Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis.

XV. INTEGRATION

23. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding between and amongst the Parties with respect to the settlement embodied in the Consent Decree and supersedes all prior agreements and understandings, whether oral or written, concerning the settlement embodied herein. No other document, nor any representation, inducement, agreement, understanding, or promise constitutes any part of this Consent Decree or the settlement it represents, nor shall it be used in construing the Terms of this Consent Decree.

XVI. FINAL JUDGMENT

24. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment of the Court as to the Parties. The Court finds that there is no just reason for delay and therefore enters this judgment as a final judgment under Rules 54 and 58 of the Federal Rules of Civil Procedure.

ENTER: April 2, 2025

THOMAS E. JOHNSTON
UNITED STATES DISTRICT JUDGE

_/s/ *J. Michael Becher*_____ Dated: _March 14, 2025_____

For the Plaintiffs Bruce Perrone, Rosanna Long, and Sierra Club

/s/ *Jeffrey A. Foster* Dated: March 14, 2025

For Commission Defendants Chairman Charlotte R. Lane, Renee A. Larrick, and William B. Raney, in their official capacities

/s/ Zachary C. Schauf Dated: March 14, 2025

For Intervenor Defendants Appalachian Power Company and Wheeling Power Company

ATTACHMENT 7

WEST VIRGINIA SECRETARY OF STATE

KRIS WARNER

ADMINISTRATIVE LAW DIVISION

eFILED
7/20/2026 1:43:53 PM
Office of West Virginia
Secretary Of State

NOTICE OF PUBLIC COMMENT PERIOD

AGENCY: Public Service Commission TITLE-SERIES: 150-41

RULE TYPE: Legislative Amendment to Existing Rule: No Repeal of existing rule: No

RULE NAME: General Investigation into adopting and implementing Rules governing Electric Generating Capacity Regulations

CITE STATUTORY AUTHORITY: 24-2-1d

COMMENTS LIMITED TO:

Written

DATE OF PUBLIC HEARING:

LOCATION OF PUBLIC HEARING:

DATE WRITTEN COMMENT PERIOD ENDS: 08/20/2026 4 PM

COMMENTS MAY BE MAILED OR EMAILED TO:

NAME: Karen Buckley

ADDRESS: Public Service Commission

PO Box 812, Charleston WV 25323

EMAIL: jneal@psc.state.wv.us

PLEASE INDICATE IF THIS FILING INCLUDES:

RELEVANT FEDERAL STATUTES OR REGULATIONS: No

(IF YES, PLEASE UPLOAD IN THE SUPPORTING DOCUMENTS FIELD)

INCORPORATED BY REFERENCE: No

(IF YES, PLEASE UPLOAD IN THE SUPPORTING DOCUMENTS FIELD)

PROVIDE A BRIEF SUMMARY OF THE CONTENT OF THE RULE:

The new Rule is designed to meet the purposes of HB 2014 to maximize the generation of electricity within this State using coal produced in the State of West Virginia. In 2025, the West Virginia Legislature amended W. Va. Code § 24-2-1d, by adding new subsections (d) through (f). In newly enacted subsection (d), the Commission is required to evaluate each capacity auction conducted by PJM Interconnection, LLC, or its successor and, to the maximum extent permitted by law, encourage the coordination of the voluntary participation of every electric generating unit in the state in each capacity auction for the benefit of ratepayers in the state. In subsection (e), in order to ensure the states existing generating units can continue to meet future generating needs, the Legislature charged the Commission to conduct a review of each generating units current consumer economic dispatch.

SUMMARIZE IN A CLEAR AND CONCISE MANNER CONTENTS OF CHANGES IN THE RULE AND A STATEMENT OF CIRCUMSTANCES REQUIRING THE RULE:

On April 12, 2025, the West Virginia Legislature passed Enrolled Committee Substitute for House Bill 2014 (HB 2014), the Power Generation and Consumption Act, effective ninety days from passage, July 11, 2025. Among other things, HB 2014 amended W. Va. Code § 24-2-1d, added a new subsections (d) through (f). In newly enacted subsection (d), the Commission is required to evaluate each capacity auction conducted by PJM Interconnection, LLC, or its successor and, to the maximum extent permitted by law, encourage the coordination of the voluntary participation of every electric generating unit in the state in each capacity auction for the benefit of ratepayers in the state. In subsection (e), in order to ensure the states existing generating units can continue to meet future generating needs, the Legislature charged the Commission to conduct a review of each generating units current consumer economic dispatch. Subsection (f) required the Commission to propose rules for legislative approval in accordance with the provisions of W. Va. Code § 29A-3-1, et seq., to carry out its duties and obligations contained in the newly enacted W. Va. Code § 24-2-1d.

SUMMARIZE IN A CLEAR AND CONCISE MANNER THE OVERALL ECONOMIC IMPACT OF THE PROPOSED RULE:

A. ECONOMIC IMPACT ON REVENUES OF STATE GOVERNMENT:

n/a

B. ECONOMIC IMPACT ON SPECIAL REVENUE ACCOUNTS:

n/a

C. ECONOMIC IMPACT OF THE RULE ON THE STATE OR ITS RESIDENTS:

n/a

D. FISCAL NOTE DETAIL:

Effect of Proposal	Fiscal Year		
	2026 Increase/Decrease (use "-")	2027 Increase/Decrease (use "-")	Fiscal Year (Upon Full Implementation)
1. Estimated Total Cost			n/a
Personal Services			
Current Expenses			
Repairs and Alterations			
Assets			
Other			
2. Estimated Total Revenues			n/a

E. EXPLANATION OF ABOVE ESTIMATES (INCLUDING LONG-RANGE EFFECT):

n/a

BY CHOOSING 'YES', I ATTEST THAT THE PREVIOUS STATEMENT IS TRUE AND CORRECT.

Yes
Jane Neal -- By my signature, I certify that I am the person authorized to file legislative rules, in accordance with West Virginia Code §29A-3-11 and §39A-3-2.

TITLE 150
LEGISLATIVE RULE
PUBLIC SERVICE COMMISSION

SERIES 41
RULES GOVERNING ELECTRIC GENERATING CAPACITY UTILIZATION

§150-41-1. General

1.1. Scope. -- The following rules govern the regulation of electric generating capacity requirements subject to the jurisdiction of the Public Service Commission pursuant to W. Va. Code §24-2-1d.

1.2 Authority. -- W. Va. Code §24-2-1d.

1.3. Filing Date. -- [ ] 2026.

1.4. Effective Date. -- [ ].

1.5. Sunset Date. – This rule shall terminate and have no further force and effect on August 1, 2031.

1.6. Intent. -- This Rule is promulgated pursuant to the mandate contained in W. Va. Code §24-2-1d(f), which required the Commission to issue rules regarding the regulation of future electric generating capacity requirements.

1.7. The contact information for the Commission is:

Public Service Commission of West Virginia
201 Brooks St.
P.O. Box 812
Charleston, WV 25323
Main switchboard telephone 304-340-0300
Main telefax 304-340-0325
Web site: www.psc.state.wv.us

§150-41-2. Definitions.

The definitions set forth in W. Va. Code §24-1-2, and the definitions for "projected deficient capacity" and "consumer economic dispatch," set forth in W. Va. Code §24-2-1d, shall apply to this rule, and have the same meanings when used herein, unless the context clearly indicates otherwise. For purposes of this rule, the following additional terms have the meanings as described below:

2.1. "Capacity factor" means the ratio of the actual energy produced by a power plant or unit within a power plant over a specific period to the maximum possible energy it could have produced if running at full capacity during that same period. Capacity factors can be calculated based on various measures of maximum possible energy production, including, but not limited to:

2.1.1. "Gross installed capacity factor" means the ratio of the gross energy produced by a power plant or unit to the maximum possible energy it could have produced if running at full installed capacity during the same period.

2.1.2. "Net installed capacity factor" means the ratio of the net energy delivered to the grid after deducting parasitic load to the maximum energy that could have been delivered to the grid after deducting parasitic load if running at full installed capacity during the same period.

2.1.3. "Gross available capacity factor" means the ratio of the gross energy produced by a power plant or unit to the maximum possible energy it could have produced if running at full available capacity during the same period.

2.1.4. "Net available capacity factor" means the ratio of the net energy delivered to the grid after deducting parasitic load to the maximum possible energy that could have been delivered to the grid after deducting parasitic load if running at the available capacity during that same period.

2.2. "Capacity Resources" means a resource that can provide electricity or reduce the demand for electricity and includes megawatts of net capacity from existing or planned Generation Resources or load reduction capability provided by demand resources.

2.3. "Effective Load Carrying Capability" (ELCC) is the capacity value fractional multiplier applied by PJM to various resources' maximum rated capacity to define their expected output during periods of maximum stress on the system. ELCC values are revised annually by PJM.

2.4. "Fixed Resource Requirement" (FRR) is an alternative option for Load Serving Entities (LSEs) to self-supply resources rather than participate in the PJM RPM auction process.

2.5. "Generation Resource" means any generating unit that meets the qualification requirements to participate in the PJM capacity market or energy market.

2.6. "Installed Capacity" (ICAP) is the summer capacity rating for capacity resources before adjustments for expected forced outages.

2.7. "Locational Marginal Price" (LPM) is the pricing mechanism used in the PJM wholesale electricity market and represents the hourly integrated marginal market clearing price for electrical energy at the location where the energy is delivered into PJM or received to serve load.

2.8. "Office of Energy" means the West Virginia Office of Energy established in W.Va. Code §5B-2F-2.

2.9. "PJM" stands for the PJM Interconnection LLC, the regional transmission organization responsible for coordinating, controlling, and transmitting electricity throughout its authorized footprint.

2.10. "Reliability Pricing Model" (RPM) is PJM's resource adequacy construct designed to acquire capacity resources to meet net capacity requirements on the PJM system.

2.11. "Self-schedule" as applied to electrical energy means the daily scheduling and control of a Generation Resource by the owner or operator of the facility that is not dependent on economic dispatch control by PJM.

2.12. "Self-schedule" as applied to electrical capacity means resources specified price takers by a resource provider in the PJM Capacity Auctions to guarantee that the resource will clear in the auction. If a resource is designated as Self-scheduled by the resource provider, the Self-Scheduled resources is cleared first in the auction before clearing any market bids.

2.13. "Unforced Capacity" (UCAP) is the MW value of a capacity resource that is available to meet demand, adjusted for the resource's expected forced outage rate.

§150-41-3. Participation in PJM Capacity Auctions.

3.1. Capacity Auctions. -- The Commission encourages voluntary participation by every electric generating unit subject to the jurisdiction of the Commission in each capacity auction.

3.2. RPM Option. -- To enable the Commission to monitor and evaluate the participation in the capacity market each electric utility subject to jurisdiction of the Commission that owns or is contractually entitled to a capacity resource and is operating under the RPM option in PJM, shall report to the Commission its proposed capacity offers for the next upcoming RPM capacity auction.

3.2.1. The utility report shall include the following:

3.2.1.a. A listing of its owned or under contract capacity resources,

3.2.1.b. The ICAP and UCAP of each resource,

3.2.1.c. The PJM assigned ELCC of each resource,

3.2.1.d. Identification of units that are eligible to bid into the capacity auction,

3.2.1.e. The UCAP quantity of each eligible resource proposed to be bid into the market,

3.2.1.f. The price proposed for each bid, which may be zero for self-scheduled capacity, and

3.2.1.g. Other information which the Commission determines is necessary to allow the Commission to meet the objectives of this subsection.

3.2.2. This report shall be submitted to the Commission at least 28 calendar days prior to submitting the capacity bid. The Commission may modify the filing deadline by a general or specific order.

3.2.3. The utility participating in this model shall also file a verified statement or testimony explaining why it chooses to forego the FRR option and the benefits to West Virginia ratepayers of remaining in the RPM. The benefits should be quantified with comparisons of the costs to ratepayers of RPM participation versus the costs of FRR participation using the RPM capacity to meet its FRR obligation. The comparisons should cover the last three PJM delivery years. The statement or testimony shall provide information on the timing and steps necessary to switch to FRR and any jurisdictional issues that would complicate such switching if required by the Commission.

3.2.4. The utility shall simultaneously file a public version and a confidential version of the quantity and price information contained in its report, which shall comply with the Commission directives for limiting and marking redacted information. The confidential version of the quantity and price information shall be deemed to be a confidential trade secret, as recognized in W.Va. Code §29B-1-4, and shall not be available to any entity seeking access to the information, unless access under a Confidentiality Agreement is required by order of the Commission.

3.3. FRR Option. -- To enable the Commission to monitor and evaluate the participation of the utility in the capacity market each electric utility subject to the jurisdiction of the Commission that owns or is contractually entitled to a capacity resource and is operating under the FRR option in PJM shall report to

the Commission its current capacity requirement as assigned by PJM, and the resources that it owns or has under contract that qualify to satisfy its PJM FRR capacity obligation.

3.3.1. The information filed shall include the following:

3.3.1.a. A description of the timing for the development of the capacity obligation by PJM,

3.3.1.b. The current ICAP and UCAP of each FRR resource,

3.3.1.c. The PJM assigned ELCC of each capacity resource, and

3.3.1.d. Other information which the Commission determines is necessary to allow the Commission to meet the objectives of this subsection.

3.3.2. This report shall be submitted to the Commission at least 28 calendar days prior to submitting the capacity bid. The Commission may modify the filing deadline by a general or specific order.

3.3.3. The FRR utility shall file a verified statement or testimony explaining why it chooses to forego the RPM and the corollary benefits to West Virginia ratepayers. The benefits should be quantified with comparisons of the costs to ratepayers of FRR capacity versus the costs of RPM participation using the FRR capacity within the RPM. The comparisons should cover the last three PJM delivery years. The statement or testimony shall also provide information on the timing and steps necessary to switch to the RPM and any jurisdictional issues that would complicate such switching if required by the Commission.

§150-41-4. Consumer Economic Dispatch.

4.1. Consumer Economic Dispatch. -- In accordance with W. Va. Code §24-2-1d(e) the commission shall review each generating unit's consumer economic dispatch to determine if each unit is operated to produce electricity at its lowest cost consistent with consumer demand, and operational limits of the generation facility and transmission facilities. To determine if the utility is operating each generating unit at its lowest cost, the Commission will review the cost of producing electricity per kilowatt hour of output at each generating unit at varying capacity utilization levels. Each electric utility subject to the jurisdiction of the Commission must plan the operation of each generating unit under its control to produce electricity at the lowest achievable cost per kilowatt hour. The Commission will review consumer economic dispatch results on a daily, weekly, monthly, and annual basis.

4.2. Generation Dispatch Reports. -- Each electric utility subject to this rule that owns or controls energy resources shall file a Generation Dispatch Report, which shall include monthly information regarding the hourly dispatch of each of its generation units into the PJM day-ahead and real-time energy markets for the month prior to the filing month. The Generation Dispatch Report is due on the tenth business day of each month, and shall include information for the month immediately preceding the filing month.

4.3. Information on Consumer Economic Dispatch. -- Each Generation Dispatch Report filed pursuant to this rule shall provide the cost of generation at various output levels. If plants are run at less than the lowest cost output levels the utility shall quantify the impact on consumer economic dispatch from running plants at less than their optimum economic capability. If running generation units at higher output levels than those achieved during any reporting period would have resulted in lower cost per kilowatt hour of output, the utility must explain why it did not maximize consumer economic dispatch of the generating units.

4.3.1. The utility should report the actual or estimated impact on maintenance costs and future equipment replacement attributable to significant ramping of unit output throughout each 24-hour period. If ramping output resulted in generating at less than optimum consumer economic dispatch was a trade-off between optimum consumer economic dispatch of generation units and lower cost market purchases, then the utility must quantify benefits of market purchases as compared to the total cost of generation, after considering the actual or estimated impact on maintenance costs and future equipment replacement attributable to ramping of unit output.

4.3.2. In a working and editable spreadsheet with the formulas intact, the report shall show for each hour of each day the following information:

4.3.2.a. The hourly installed gross and net capacity available to be bid or self-scheduled into the day-ahead market,

4. 3.2.b. The hourly volume of net capacity bid into the market and the related cost-based and market-based bid amounts as dollars per megawatt hour,

4. 3.2.c. The hourly net capacity that cleared the day-ahead market,

4. 3.2.d. The hourly self-scheduled capacity delivered into the day-ahead market, and

4.3.2.e. The hourly PJM LMP at the pricing nodes for each capacity resource, including the PJM identification number for each node. The report shall also show energy delivered into the PJM real-time energy market.

4.3.3. Each Generation Dispatch Report shall provide the schedules of availability for seven days in advance provided to PJM during the report month as required by PJM Manual 11 as follows: "Generation Capacity Resources that have an RPM or FRR commitment shall submit a schedule of availability for the next seven (7) days and may submit non-binding offer prices for the days beyond the next Operating Day." (*See* PJM Manual 11 at page 27, https://www.pjm.com/-/media/DotCom/documents/manuals/m11.pdf, effective October 1, 2025.)

4.3.4. The Generation Dispatch Report shall also indicate multiple-day volumes and offer prices if energy market offers or Self-scheduled volumes were submitted for days beyond the next Operating Day.

4.4. Alternative. -- If a utility subject to this rule has chosen not to self-schedule all or any of its generation capacity during any day or portions of a day it shall explain why it made that decision. This explanation must be included in its monthly Generation Dispatch Report.

§150-41-5. Capacity Factors.

5.1. Information on Capacity Factors. -- Each electric utility subject to the rate jurisdiction of the Commission that operates generation facilities shall report in its Generation Dispatch Report the capacity factors achieved at each generating unit relative to the following:

5.1.1. Maximum nameplate generation capacity of each unit,

5.1.2. Net maximum generation capacity of each unit after plant parasitic load,

5.1.3. Available nameplate generation capacity of each generating unit,

5.1.4. Available net maximum generation capacity of each unit after plant parasitic load; and

5.1.5 The underlying values supporting the calculated capacity factors.

5.2. Verified Statement. -- Each electric utility shall include in its Generation Dispatch Report a verified statement which may be in standard narrative format or in question and answer format explaining the causes and reasons that the net capacity after parasitic plant use was not one hundred percent of installed capacity net of typical plant use. The report shall include:

5.2.1. Reasons for outages;

5.2.2. Duration of outages;

5.2.3. Remedial action scheduled to remedy outages;

5.2.4. Time when the outage first occurred;

5.2.5. Time when the outage was remediated;

5.2.6. Total elapsed hours of each outage; and,

5.2.7. Direct incremental cost of each remediation, excluding overheads. Direct incremental costs are those costs that would not have been incurred but for the remediation.

5.3. Capacity Factor. -- The Commission expects generating electric utilities subject to the rate jurisdiction of the Commission to maintain their generation plants and schedule maintenance to minimize down time to allow it to achieve a minimum capacity factor of sixty-nine (69%) percent. The success in achieving a minimum capacity factor will initially be measured over a twelve-month period.

5.3.1. The utilities will include in their monthly Generation Dispatch Reports their actual capacity factors in tabular format for the report month and a rolling average up to December. Beginning with January of each year the rolling average reported shall restart. All prior month's data shall continue to be reported even though the rolling average is restarted.

5.3.2. The utilities are expected to take advantage of PJM Manual 11 Market Rules 2.3.3., *et seq.*, which allow self-scheduling rather than allowing PJM to accept or reject their output into the day-ahead market. The utility is not expected to operate at a net-positive margin in all hours of the day. It is expected to reasonably anticipate and project expected day-ahead market prices and schedule increments of generation to minimize negative margins during periods of low market prices while allowing for reasonable, and limited ramping of generation levels as market prices fluctuate in the day-ahead market.

§150-41-6. Management of fuel supplies and contracts.

6.1. Information on Fuel. -- At the time of filing of the Generation Dispatch Report, the electric utility shall file a PDF file properly formatted for printing as an 8 ½ x 11 inch document or a printed document along with a spreadsheet relating to the fuel supplies for the utility.

6.1.1. The Generation Dispatch Report shall include the following information:

6.1.1.a. The average cost and the volumes of coal in inventory at the beginning of the report

month at each coal stockpile location;

6.1.1.b. The volumes and cost of coal delivered into the stockpile(s) during the month;

6.1.1.c. The volumes burned each month;

6.1.1.d. Any stockpile adjustments made during the month; and

6.1.1.e. The average cost and the volumes of coal in inventory at the end of the month.

6.1.2. The volumes and costs of coal in inventory shall be reported on both a tonnage basis and million British thermal unit ("MMBTu") basis.

6.1.3. The report shall also show the detailed total dollars and weighed average cost of coal per ton for each of the four volume categories listed above, divided between F.O.B. mine, transportation, and handling costs, both transportation and in-plant related, if applicable.

6.2. Summary Price Adjustments. -- The utility shall include a summary of price adjustments at each coal stockpile location applicable to prior months that were not known at the time reports for those months were made.

6.2.1. If there was a stockpile adjustment for any report month, the utility shall file a copy of the stockpile report and the derivation of the adjustment in tons and dollars.

6.2.2. If any stockpile adjustment exceeds five percent of the tonnage or dollar value of the inventory, the electric utility shall file a verified statement or testimony explaining the reasons that the stockpile had been misreported in the past.

6.3. Solicited Bids for Coal. -- For each monthly Generated Dispatch Report, the utility shall report the expected date for its next solicitation of bids for coal. It shall also report on the results and details of any bids received and contracts consummated prior to the report month.

6.4. Coal Contracting. -- When eliciting requests for coal contracting proposals, each electric utility subject to these rules shall make it clear that contracts indexed to the price of PJM day-ahead LMP will be considered. It shall indicate that alternative indexing that is expected to follow electricity wholesale prices in PJM may also be offered and will be considered by the utility. It shall make it clear that proposals may contain only an indexed contract or a mix of fixed-price and indexed contracts. The utility shall endeavor to maintain a mix of short-term and long-term contracts that also contain a mix of fixed-price and indexed contracts.

§150-41-7. Additional information.

7.1. Additional Information. -- The information required by this rule is not exhaustive of all information that the electric utility must provide.

7.1.1. The Commission may require additional or differently formatted information if the Commission determines that the additional information is necessary:

7.1.1.a. To ensure that the utility is maximizing the production of electricity from their generating units,

7.1.1.b. To ensure that the utility is acting to reduce energy costs for West Virginia ratepayers, or

7.1.1.c. To clarify, explain, justify, or further explain any information required by the code or this rule to be provided to the Commission.

7.1.2. A modification may be achieved by general order, specific order applicable to a single utility, or as a request from the Commission or designated staff.

7.1.3. It shall be the responsibility of the utility to provide timely additional requested information.

7.2. Amended Deadlines. – If a utility is unable to meet a deadline required by this rule, and such failure is because it has not or cannot receive the PJM in time, or for any reason outside the control of the utility, then the utility may request the Commission to modify the deadline. The Commission may grant the requested modification, for good cause shown, and shall set a new deadline. The Commission may employ a standard extension timeframe for utilities, when the cause for the deadline extension is a failure to timely receive PJM information.

§150-41-8. Confidentiality

8.1. In addition to section 3.2.4 of this rule, but subject to the other provisions of this section, all confidential business information, including trade secrets or other proprietary data or processes, shall be exempt from disclosure pursuant to W. Va. Code §§29B-1-1 *et seq.*

8.2. The Commission shall forward, share, or otherwise make available to the Director of the Office of Energy all unredacted reports and records provided to the Commission pursuant to this rule. The Office of Energy shall be bound by the same confidentiality restrictions as the Commission, and may not publicly disclose confidential business information.

8.3. Nothing contained herein precludes either the Commission or the Office of Energy from relying upon confidential business information or other protected information to address challenges with, and make improvements to, the state of energy in West Virginia. Protected information may be used to develop an energy plan, manage affordability, increase availability, rectify vulnerabilities, or take any other action consistent with the statutory directives of either the Commission or the Office of Energy. Any data compilation, plan, report, or other document which is made publicly available shall not include confidential business information which can be readily associated with the source utility. Such restrictions does not extend to information which is not determined to be confidential, and which is not otherwise protected by law.