UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF WEST VIRGINIA
AT CHARLESTON

BRUCE PERRONE,
ROSANNA LONG, and
SIERRA CLUB,

Plaintiffs,

v.

CHAIRMAN CHARLOTTE R. LANE,
in her official capacity, COMMISSIONER
RENEE A. LARRICK, *in her official capacity*,
and COMMISSIONER WILLIAM B. RANEY,
in his official capacity,

Defendants.

COMPLAINT FOR DECLARATORY AND INJUNCTIVE RELIEF

Plaintiffs Bruce Perrone, Rosanna Long, and Sierra Club bring this action against West Virginia Public Service Commission Chairman Charlotte Lane, Commissioner Renee Larrick, and Commissioner William Raney, in their official capacities (together, the "Defendants" or the "Commissioners"). In support, Plaintiffs respectfully state as follows:

NATURE OF THE ACTION

1. This case involves a series of unlawful orders issued by the Commissioners of the West Virginia Public Service Commission (the "Commission"), directing Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo") to fire their coal-fired power plants at a 69% capacity factor (the "69% Directive").

2. Capacity factor is the ratio (usually expressed as a percentage) of energy produced by a generating unit for a period of time (usually one year) to the energy that could have been

produced at continuous full power operation during the same period. APCo and WPCo's 7-year average capacity factors for each of its coal-fired units is 55% or below, and the 10-year average capacity factor for all coal-fired units in PJM is only 41.9%. *See infra* pars. 99–101.

3. The Commissioners issued the 69% Directive so that APCo and WPCo would fire their coal-fired power plants as much as possible and far more than they have historically.

4. However, APCo and WPCo cannot achieve a 69% capacity factor economically—if they could, they would already be doing so, and there would be no reason for imposing a capacity factor directive.

5. In essence, the 69% Directive creates a "bid-and-clear" requirement that regulates and ultimately increases APCO and WPCo's participation in the wholesale market—a matter firmly within FERC's exclusive authority.

6. Thus, because this "bid-and-clear" requirement infringes on a matter wholly within FERC's jurisdiction, it violates the Supremacy Clause and is preempted under binding precedent. *See Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 166 (2016) (striking down state program under preemption because it tethered payment on bidding into and clearing the wholesale market, which is purely FERC's jurisdiction); *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); *see also Rochester Gas & Elec. Corp. v. Pub. Serv. Comm'n of State of N.Y.*, 754 F.2d 99, 102 (2d Cir. 1985); *Coalition for Competitive Electricity v. Zibelman*, 906 F.3d 41, 52 (2d Cir. 2018) ("What mattered in *Rochester Gas* was whether the retail rate adjustment, which factored in expected wholesale revenues, intruded on FERC's jurisdictional turf by compelling wholesale market participation."); *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 compulsion—plainly involves the regulation of wholesale sales and thus falls squarely within the field that Congress has occupied" in the FPA).

7. Ratepayers in West Virginia have subsidized and will continue to subsidize higher retail electricity rates from APCo and WPCo's uneconomic dispatch of coal as a result of the Commissioners' unlawful Directive.

8. For these reasons, Plaintiffs bring this action for an order permanently enjoining the Commissioners from enforcing the 69% Directive and declaring that such Directive violates the Supremacy Clause of the United States Constitution.

PARTIES

9. Plaintiff Bruce Perrone is an individual who resides in Kanawha County, West Virginia, is served by APCo, and pays for his electricity consumption at his residence.

10. Plaintiff Rosanna Long is an individual who also resides in Kanawha County, West Virginia, is served by APCo, and pays for her electricity consumption at her residence.

11. Plaintiff Sierra Club is a nonprofit corporation incorporated in California, with more than 748,000 members and supporters nationwide, including approximately 2,400 members who reside in West Virginia and belong to its West Virginia Chapter. The Sierra Club is dedicated to exploring, enjoying, and protecting the wild places of the Earth; to practicing and promoting the responsible use of the Earth's resources and ecosystems; to educating and enlisting humanity to protect and restore the quality of the natural human environment and to using all lawful means carrying out these objectives. The Sierra Club's concerns encompass the use of coal and its effects on the climate due to its high carbon dioxide emissions, and the Sierra Club actively promotes the transition away from fossil fuels and toward local renewable energy sources.

12. Charlotte Lane is the Chairman of the West Virginia PSC. She is named in her official capacity.

13. Renee Larrick is a Commissioner of the West Virginia PSC. She is named in her official capacity.

14. William Raney is a Commissioner of the West Virginia PSC. He is named in his official capacity.

JURISDICTION AND VENUE

15. This Court has subject matter jurisdiction over Plaintiffs' claims arising under the U.S. Constitution and federal law pursuant to 28 U.S.C. § 1331.

16. The Court is empowered to grant declaratory relief by 28 U.S.C. §§ 2201 and 2202 and Rule 57 of the Federal Rules of Civil Procedure.

17. This Court is empowered to grant preliminary and permanent injunctive relief by, *inter alia*, 28 U.S.C. § 2202 and Rule 65 of the Federal Rules of Civil Procedure.

18. The West Virginia Commission itself is protected by sovereign immunity. *See Lackawanna Transp. Co. v. Pub. Serv. Comm'n of W. Va.,* No. 5:08CV66, 2008 WL 5378318, at *3 (N.D. W. Va. Dec. 23, 2008) ("Because the Public Service Commission is a state agency, it is immune from suit as to Lackawanna's claims unless Congress has abrogated immunity or the Public Service Commission has consented to suit."). However, the individual commissioners can be sued in their official capacity for injunctive relief pursuant to *Ex Parte Young*. *See Lackawanna Transp.*, 2008 WL 5378318, at *4–8 (allowing Plaintiff to amend its complaint and substitute the WV PSC out and sue the commissioners individually in their official capacity).

19. This Court has personal jurisdiction over Defendants in their official capacity because each Defendant conducts a substantial portion of his or her duties as an officer of the West

Virginia Public Service Commission in the Southern District of West Virginia. The Commission's main office is located at 201 Brooks Street, Charleston, WV 25301.

20. Venue is proper in this District under 28 U.S.C. § 1391(b)(2) because a substantial part of the events giving rise to this action occurred in Charleston, West Virginia, in the Southern District of West Virginia. Venue is also proper in this District under 28 U.S.C. § 1391(b)(1) because Chairman Lane lives in Charleston, West Virginia, and Commissioners Larrick and Raney both live in the State of West Virginia.

STANDING

21. The 69% Directive forces West Virginia ratepayers—including Bruce Perrone, Rosanna Long, and many Sierra Club members—to subsidize APCo and WPCo running their coal-fired power plants more often than they otherwise would through higher residential retail electricity rates.

22. Bruce Perrone lives at 2502 Jakes Run Road, Elkview, WV 25071. Mr. Perrone pays APCo (through AEP) for the electricity consumed at his residence, thus making Mr. Perrone a ratepayer of APCo. Mr. Perrone has experienced rising electricity rates over the past few years and does not want his rates to continue to increase, particularly in order to subsidize the uneconomic dispatch of APCo's and WPCo's power plants.

23. Rosanna Long lives at 1519 Autumn Road, Charleston, WV 25314. Ms. Long pays APCo for the electricity consumed at her residence, thus making her a ratepayer of APCo. Like Mr. Perrone, Ms. Long does not want her electricity rates, which are already high, to continue to increase, particularly in order to subsidize the uneconomic dispatch of APCo's and WPCo's power plants.

24. The Sierra Club has at least one office space located in West Virginia, and it pays for electricity, specifically through APCo and/or WPCo, thus making the organization itself a ratepayer that will have to subsidize higher retail electricity rates and a greater reliance on coal generation.

25. West Virginia Sierra Club also sues on behalf of their West Virginia Sierra Club members Andrew Earley, Jonah Kone, and Mattie McClanahan, who reside in Charleston, West Virginia, are served by APCo, and pay for their electricity consumption at their respective residences. They have all noticed that their electricity bills have been increasing, and they do not want to pay higher rates in order to prop up West Virginia coal plants' uneconomic dispatch in compliance with the Commissioners' 69% Directive.

26. The Sierra Club members' injuries are germane to Sierra Club's mission to replace fossil fuel generation with cleaner energy sources and the Club's "promotion of energy conservation through appropriately designed electrical utility rate structures which, in conjunction with additional regulatory activity, minimize the emission of environmental pollutants." *See Electric Utility Rate Structures*, available at https://www.sierraclub.org/policy/energy/electric-utility-rate-structures.

27. Plaintiffs' injuries are fairly traceable to the conduct of Defendants because their 69% Directive has caused and will continue to cause the uneconomic dispatch of coal units, has contributed to higher electricity prices, and threatens to raise consumer rates even more in the future.

28. A favorable order by this Court will redress Plaintiffs' injuries—an order enjoining the 69% Directive will result in APCo and WPCo operating their plants only when it is

economical to do so, thus saving ratepayers money and decreasing the amount of coal burned for baseload power generation.

FACTUAL ALLEGATIONS

PJM, the Wholesale Market, and the Retail Market

29. A wholesale sale is defined as a "sale of electric energy to any person for resale." 16 U.S.C. § 824(d).

30. The Federal Power Act gives FERC exclusive jurisdiction to regulate wholesale electricity transactions in interstate commerce, including the transactions that affect the price for wholesale energy and capacity. It thereby establishes a bright line, preempting states from regulating such wholesale sales in any way. *See* 16 U.S.C. § 824(b)(l) (giving FERC exclusive jurisdiction over the sale of electricity "at wholesale").

31. However, FERC has concluded that market-based wholesale rates are just and reasonable when they are negotiated in a fully competitive environment. In some regions of the country, including West Virginia, utilities have formed regional transmission organizations ("RTOs") that administer centralized wholesale markets. Rather than FERC setting wholesale rates directly, FERC oversees the rules that these markets operate under to ensure they lead to rates that are just and reasonable.

32. One of those RTOs, PJM Interconnection ("PJM"), operates a competitive wholesale electricity market to ensure reliability for more than 65 million customers in all or parts of 13 states (including West Virginia) and the District of Columbia. *See* "PJM Who We Are," www.pjm.com.

33. States, however, have exclusive jurisdiction over "'any other sale'—most notably, any retail sale—of electricity." *FERC v. EPSA*, 577 U.S. 260, 265 (2016) (quoting 16 U.S.C. § 824(b)).

34. The states' reserved authority includes control over in-state "facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1); *see Pacific Gas & Elec. Co. v. State Energy Resources Conservation and Development Comm'n*, 461 U.S. 190, 205 (1983) ("Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States.").

35. The electricity transmission grid serving West Virginia and the rest of the PJM region is part of an integrated interstate network. Electricity delivered into that grid by a particular generating facility cannot be segregated from electricity produced elsewhere and flowing in interstate commerce, with the result that all sales of wholesale electricity within PJM occur in interstate commerce subject to regulation by Congress and FERC.

APCo's and WPCo's Operations in PJM

36. APCo owns and operates two coal-fired electric generating facilities in West Virginia: the Amos Plant and the Mountaineer Plant. In addition, APCo owns and operates gas-fired electric generating facilities and hydroelectric facilities, and purchases power from hydroelectric, wind, solar and coal-fired facilities under agreements that are commonly known as "power purchase agreements."

37. WPCo owns a 50% undivided interest in the coal-fired Mitchell Plant, also located in West Virginia.

38. To serve the electric energy needs of their customers, APCo and WPCo rely upon their portfolio of owned generation and power purchase agreements, as well as energy purchases from the PJM Energy Market.

39. Each day, APCo and WPCo (and all other PJM participating utilities) offer their available electric generation into the PJM Energy Market.

40. The PJM Energy Market requires PJM to forecast the next day's anticipated electricity demands and secure enough bids to fulfill that demand (known as the "Day-Ahead Market").

41. The PJM Energy Market also includes a component that enables PJM to buy and sell electricity to distributors for delivery within the next hour if the bids secured on the Day-Ahead Market were not enough to satisfy the real-time demand on the grid through the "Real-Time Energy Market." Prices in the Real-Time Energy Market are often referred to as "Spot Pricing."

42. Through an auction process, PJM determines a "Market-Clearing Price" by allowing generating resources to offer in a price at which they can supply a specific number of megawatt-hours of power.

43. The cheapest resource will "clear" the market first, followed by the next cheapest option, and so forth until demand is met.

44. When supply matches demand, the market is "cleared," and the price of the last resource to offer in (plus other market operation charges) is the Market-Clearing Price and becomes the wholesale price of power for all the generators whose bids were accepted in the auction.

45. With limited exceptions, bids above the market-clearing price are not accepted and those resources will not dispatch energy into the PJM Energy Market.

46. The market auction process ensures that customer demand will be met by the lowest-cost generators.

47. "Economic Dispatch" occurs when the Market-Clearing Price is greater than or equal to the operating costs of a generator (e.g., APCo's Amos Plant). In other words, a generation unit is economically dispatched when it is able to profit or break even on an electricity sale.

48. If an operator does not receive a Market-Clearing Price greater than or equal its costs to produce and sell electricity, its dispatch will be uneconomic. In other words, it will lose money on the sale. But because the Market-Clearing Price is based on the last offer that clears the market, uneconomic dispatch will occur only if a unit clears the market with a bid that is too low to cover its operating costs—i.e., an artificially low bid.

49. As an exception to the market auction process, an operator may also self-select units for generation, in which case it will receive a price based on the Market-Clearing Price regardless of its bid. This too may result in uneconomic dispatch.

50. Pursuant to PJM's FERC-approved open access transmission tariff, APCo and WPCo must bid and sell into the PJM energy market all electricity produced at facilities designated to meet the companies' capacity obligations. *See* PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 1, section 1.10.1A (d), *available at* https://agreements.pjm.com/oa/4666.

51. At all relevant times, APCo and WPCo have designated the Amos, Mountaineer, and their share of the Mitchell coal-fired power plants as resources to meet their capacity obligations. *See, e.g.*, Resources Designated In 2022/2023 FRR Capacity Plans as of 4/23/2021, *available at* https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-

2023-resources-designated-in-frr-plans.ashx. This designation obligates APCo and WPCo to sell energy produced by these plants through the PJM energy market.

52. Because APCo and WPCo have coal-fired power plants, which take time to come on or offline, they are most often utilizing and bidding into the PJM Day-Ahead Market.

53. The key drivers for APCo's and WPCo's offer price into the PJM Energy Market are the cost and availability of fuel to run their electric generating units.

54. While APCo and WPCo determine the offers that they submit each day, it is PJM, through its markets, that ultimately determines how much electricity the available resources of APCo and WPCo and other utilities will generate on a day-to-day basis, based on the offers submitted. Under normal circumstances, APCo, WPCo, or any other operator would only offer a price in which it could achieve an Economic Dispatch and only dispatch when its bids clear the market auction.

55. When purchasing power from the PJM Energy Market is cheaper than self-generation, principles of economic dispatch would demand APCo and WPCo use less of their own generation and purchase more energy from that market to meet their customers' needs in the most economical manner.

56. The amount that a particular unit ultimately dispatches into PJM is commonly referred to as its capacity factor. For example, a unit that is available and dispatched 30% of the hours of the year would have a 30% capacity factor.

The Public Service Commission

57. State utility commissions regulate the electric utilities that provide retail service in their respective states. For example, because APCo serves customers in both West Virginia and

Virginia, its retail service is regulated by both the West Virginia Commission and the Virginia State Corporation Commission ("SCC").

58. Generally speaking, utility commissions are charged with assuring utilities provide reliable services to customers for a reasonable rate.

59. APCo and WPCo play a dual role in PJM's energy markets. As public utilities, APCo and WPCo are responsible under state law for delivering electricity to retail customers. In PJM's parlance, that makes them "load serving entities" who purchase energy on the PJM market to meet their customers' demand.

60. But because they operate their own power plants, they are also "generators" that sell into the PJM market. Their bids into PJM's energy market influence the Market-Clearing Price, and they may be able to offset the cost of energy purchases with revenue from energy sales.

61. The West Virginia Commission sets the retail rate that APCo, WPCo, and other utilities can charge retail customers for electricity. Under the United States Constitution, the rates approved by the Commission must allow APCo, WPCo, and other utilities to recover their prudently incurred costs and make a reasonable rate of return. *See Bluefield Waterworks & Improvement Co. v. Public Service Commission*, 262 U.S. 679, 690 (1923).

62. Retail electricity rates contain several components that are considered separately to ensure costs are allocated to the customer classes most responsible for them. *See In re Clarksburg Water Bd.*, No. 07-0541-W-MA, 2007 WL 5022606 (W. Va. P.S.C. Sept. 19, 2007).

63. One component of retail rates is the cost of fuel (and related expenses) and purchased power used to serve customers. In West Virginia, this portion of the Commission-approved rate is known as the Expanded Net Energy Cost ("ENEC").

64. Each year, electric utilities—including APCo and WPCo—file a petition to initiate the annual review and update of ENEC rates.

65. Generally, this annual filing requests that the Commission approve ENEC rate adjustments to retail electricity rates that consist of (1) a true-up of actual costs for the previous year (the "historical" or "review" period) and (2) an estimate of the next year's projected costs (the "forecast" period).

66. To "true up" their ENEC rates in any given proceeding, electric utilities will seek to increase rates for any under-recovery of their actual costs incurred during the review period or, alternatively, will seek to credit back to customers any over-recovery that exceeded their actual costs.

67. The purpose of an ENEC proceeding is to determine the component of retail rates that compensates an electric utility for the fuel, purchased power, and other related costs it prudently incurs to produce and provide electricity to its customers.

68. The Commission is tasked with determining whether APCo's and WPCo's costs were prudent. West Virginia law requires the Commission to approve rates that allow APCo and WPCo to recover prudently incurred costs.

69. The prudence of a utility decision depends on its reasonableness given what was known or reasonably knowable at the time the decision was made. *See In re Hope Gas, Inc.*, Case No. 12-1070-G-30C, 2013 WL 2370525 (W. Va. P.S.C. May 10, 2013); *In re Appalachian Power Co.*, Case No. 09-0177-E-G1, 2009 WL 3756478 (W. Va. P.S.C. Sept. 30, 2009); *In re Hope Gas, Inc.*, Case No. 04-1188-G-30C7, 2006 WL 2134651 (W. Va. P.S.C. April 3, 2006).

70. Any costs that the Commission allows APCo and WPCo to recover ultimately come from the ratepayer in the form of higher retail electricity rates.

71. APCo's and WPCo's recent ENEC proceedings and the facts surrounding them underlie this Complaint.

APCo's and WPCo's ENEC Proceedings

72. *2021 ENEC Case (21-0339-E-ENEC)*. On April 16, 2021, APCo and WPCo initiated their 2021 ENEC case and requested additional annual ENEC revenues of approximately $73 million, comprised of $55.4 million for under-recovery of costs during the review period (March 1, 2020, through February 28, 2021) and $17.6 million in projected increased costs for the forecast period (September 1, 2021, through August 31, 2022). The Commission issued its first substantive order in the 2021 ENEC case on September 2, 2021, granting only a $6 million rate increase. APCo and WPCo filed a Petition for Reconsideration or Clarification of that Order. On March 2, 2022, the Commission entered an order granting, in part, the Petition for Reconsideration and increasing the APCo's and WPCo's ENEC rates by $31.4 million and reopened the evidentiary record of the 2021 ENEC case to take additional evidence on the causes of APCo's and WPCo's growing ENEC under-recovery. On March 14, 2022, APCo and WPCo filed testimony and exhibits of six witnesses in the 2021 ENEC case. The second evidentiary hearing in the 2021 ENEC case was held on March 23, 2022. On May 13, 2022, the Commission issued a further order in the 2021 ENEC case, which granted APCo and WPCo recovery of an additional $93 million for projected increased costs, subject to future review for prudence, and ordered its Staff to conduct a prudence review of APCo's and WPCo's policies and procedures for maximizing and maintaining adequate fuel inventory levels and maximizing self-generation.

73. *2022 ENEC Case (22-0393-E-ENEC)*. On April 19, 2022, APCo and WPCo filed a petition to initiate their 2022 ENEC case, in which they sought an annual ENEC rate increase of approximately $297 million, consisting of an under-recovery balance of $212.7 million (as of

February 28, 2022) and a projected increase of approximately $83.9 million for the forecast period (September 1, 2022 through August 31, 2023), supported by the direct testimony and exhibits of eight witnesses. Other parties and Staff filed the direct testimonies of their respective witnesses on September 9, 2022. On September 23, 2022, APCo and WPCo filed the rebuttal testimonies and exhibits of seven witnesses, including an outside consultant engaged to review and opine on, inter alia, the circumstances prevailing throughout the review period. On October 4–5, 2022, the Commission held the first of two evidentiary hearings in the 2022 ENEC case. On February 3, 2023, the Commission issued an order in the 2022 ENEC case that deferred a decision on APCo's and WPCo's requested rate increase until completion of the Staffs prudence review.

74. *2023 ENEC Case (23-0377-E-ENEC)*. On April 28, 2023, APCo and WPCo filed a petition to initiate their 2023 ENEC case, in which they requested the recovery of approximately $641.7 million, comprised of an accumulated under-recovery balance of approximately $552.9 million (as of February 28, 2023) and a projected increase of approximately $88.8 million for the forecast period (September 1, 2023 through August 31, 2024).

75. On April 28, 2023, the Staff filed the "Independent Technical Prudency Review of the Activities Affecting the Operation of Amos, Mountaineer, and Mitchell Coal Plants Case Nos. 22-0393-E-ENEC and 21-0339-E-ENEC" that had been prepared by its consultant CTC (hereinafter, the "CTC Report").

76. On May 26, 2023, the Commission issued an order in the 2021, 2022, and 2023 ENEC cases, which reopened all three cases in order to set a procedural schedule for taking evidence on the CTC Report.

77. APCo and WPCo filed direct testimony in response to the CTC Report on July 28, 2023.

78. Other parties and Staff filed testimony in all three cases on August 15, 2023.

79. On August 29, 2023, APCo and WPCo filed the rebuttal testimony and exhibits of six witnesses in all three cases.

80. On September 5–7, 2023, the Commission convened an evidentiary hearing on the 2021, 2022, and 2023 ENEC cases—the third such hearing in the 2021 case, the second in the 2022 case, and the only hearing in the 2023 case.

81. On January 9, 2024, the Commission issued a final Order in the 2021, 2022, and 2023 ENEC cases.

The 69% Directive

82. Beginning in 2021, when reviewing APCo's and WPCo's ENEC rates, the Commission directed them to run their coal-fired power plants at a 69% capacity factor (the "69% Directive").

83. The Commission has reiterated and reinforced the 69% Directive in subsequent orders and hearings relating to the 2021, 2022, and 2023 ENEC proceedings.

84. Specifically, the Commission has directed APCo and WPCo to run their coal-fired power plants at a 69% capacity factor or reminded APCo and WPCo of such Directive on at least eight separate occasions:

a. In a September 2, 2021 Order relating to the 2021 ENEC proceeding, in its fourth Conclusion of Law, the Commission expressly concluded that APCo's and WPCo's "capacity factor projections are too low," and the capacity factor for Amos, Mountaineer, and Mitchell "should be 69 percent in this case with the potential for an increased capacity factor in this case with the potential for an increased capacity factor as described in this order."

b. In a March 2, 2022 Order relating to the 2021 ENEC proceeding, the Commission confirmed the intent of the September 2021 order "to require the Companies to follow a power supply policy to maximize their use of fossil-fuel generation" and reprimanded APCo and WPCo for failing to meet the 69% Directive in the months since its initial decision and set the matter for a hearing at which they could explain why they were "severely curtailing their own generation" at Amos, Mountaineer, and Mitchell.

c. At a March 23, 2022 hearing for the 2021 ENEC proceeding, Chairman Lane expressed concern that APCo and WPCo were not taking the 69% Directive seriously:

> CHAIR: Mr. Dial, I'm going to start off with a statement you made, and I can't state it exactly what you said, but the way I interpreted what you said to me was that you didn't take our 69-percent capacity seriously. That you thought we didn't really mean it, that maybe it was sort of a target that you should look at.
>
> A: Okay. So I guess I was never told by anybody that we should be procuring to a 69-percent capacity factor.
>
> CHAIR: So that's why we're in this problem that we're in today?
>
> A: I would say that's part of the problem.
>
> CHAIR: Okay. I'm sort of speechless

d. In a May 13, 2022 Order relating to the 2021 ENEC proceeding, according to the Findings of Fact, "[t]he Companies have not achieved 69 percent capacity at their coal-fired generating plants as ordered by the Commission" and, "[g]iven the large under-recovery balance and the Commission's direction to the Companies to run their coal-fired generation plants at 69 percent capacity, which has not yet been achieved," it was necessary for the "Commission Staff to conduct a separate prudency review for expenses incurred in the 2020–21 and 2021–22 ENEC years."

e. At an October 4, 2022 evidentiary hearing in the 2022 ENEC proceeding, Chairman Lane had an exchange with Randall Short, APCo's director of regulatory services for West Virginia:

> CHAIR: Mr. Short, the information that you filed with the Commission indicates that you all have not complied with the 69 percent. What is it going to take to get your attention that we really mean 69 percent?
>
> A: You fully have our attention, Chairman. I respectfully answered that question that we have sought some clarification because we believe there are issues with the 69 percent involving multi-jurisdictional recovery if another jurisdiction deems that that was outside the economic dispatch model. And I'm not trying to force anyone's hand, but those are questions that we still believe we'd like to have an answer to—
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> CHAIR: Well, let's assume that you got the answer in the Order that is out there now, and we're not going to go any further than what we've already said.

f. At the second day of the evidentiary hearing relating to the 2022 ENEC proceeding, on October 5, 2022, Chairman Lane asked Jeffrey Dial, APCo's director of coal transportation and procurement, "who is in charge of seeing that the plants are running at 69 percent?"

g. In a February 3, 2023 Order relating to the 2022 ENEC proceeding, the Commission explained in its order that "[t]he 69 percent was, therefore, an expected minimum based on the record before us at the time regarding purchased power costs and generation costs."

h. In a January 9, 2024 Order relating to the 2021, 2022, and 2023 ENEC proceedings, the Commission criticized APCo and WPCo several times for failing to have enough coal on hand to operate at a 69% capacity factor.

85. The 69% Directive compels APCo and WPCo to operate and sell their output from their coal-fired power plants into PJM more often and at lower prices than they otherwise would under Economic Dispatch principles.

86. Under the Commissioners' orders, if APCo and WPCo do not run their plants at a 69% capacity factor—which requires that they bid into and clear the PJM market 69% of the year—they risk being denied cost recovery. Conversely, they are able to justify cost recovery much more simply if the plants run at or above the 69% threshold. Specifically, in its February 3, 2023 Order, the Commissioners created what they characterize as a rebuttable presumption of reasonableness for analyzing whether APCo and WPCo would be granted cost recovery based on the 69% capacity factor:

> We made it clear that the first step in our future review of the reasonableness of net ENEC costs would be to determine if the Companies had achieved that [69% capacity factor] expectation. Reaching that goal would not, by itself, be dispositive of the question of reasonableness of net ENEC costs if the costs were challenged by competent evidence. However, it would be easier for the Companies to meet their burden of proof regarding reasonableness of costs and prudence of their management of ENEC costs if they achieve the 69 percent annual capacity factor. On the other hand, if they do not achieve the 69 percent capacity factor, we made it clear that the burden would be on the Companies to demonstrate that their actions that affected net ENEC costs were prudent and that the resulting net ENEC costs were reasonable and should be included in rates. The actions that would be necessary to demonstrate prudence will include: (1) maintaining adequate economical fuel supplies, (2) keeping plants available for generation the maximum amount of time, (3) maximum reduction, in accordance with good engineering and operating practices, of outage times related to maintenance, repairs, equipment modifications, site modifications, or other reasons, and (4) effectively bidding to clear the PJM energy market considering the possibility of some negative hourly net margins that were necessary to maximize ensuing positive hourly net margins.

Thus, the Commissioners have also directed APCo and WPCo to enter bids into PJM markets lower than their operating costs by offering to reimburse those costs through the ENEC proceeding in order to achieve a 69% capacity factor.

87. A presumption for or against the reasonableness of costs is a critical factor in utility ratemaking; a utility generally cannot recoup any costs it incurs in serving customers if the Commission deems those costs unreasonable. *See In re Monongahela Power Co.*, No. 08-1511-E-GI, 2008 WL 10624127, at *2 (W. Va. P.S.C. Dec. 29, 2008).

88. The CTC Report, prepared on behalf of the Staff for the Commission-mandated prudence review, evaluated APCo's and WPCo's compliance with the 69% Directive. The CTC Report suggested to the Commission that the Companies' costs should be denied in proportion to its failure to run at a 69% capacity factor. Specifically, CTC found that APCo and WPCo only achieved an aggregate capacity factor of 32.5%, which is only 47.1% of a 69% capacity factor. The CTC Report ultimately recommended that the Commission disallow $202 million in cost recovery.

89. In its January 9, 2024 Order, the Commission disallowed $231 million in cost recovery for APCo and WPCo—a similar amount to what the Staff's CTC Report recommended be disallowed.

90. The January 2024 Order faulted the Companies for failing to have enough coal on hand to run at the 69% factor, and thereby take advantage of high PJM energy prices.

91. However, the January 2024 Order fails to acknowledge that APCo and WPCo had no way of knowing that it would need enough coal to run at 69% capacity, as PJM prices spiked higher than they had in years with little to no warning.

92. As APCo and WPCo argue in a recent appeal of the January 2024 Order to the West Virginia Supreme Court, their procurement of coal and operation was prudent based on past experience with the market and the recovery of costs should be based on the prudency of management decisions at the time and not on hindsight. APCo Appellate Br. at 17.

93. Further, the Commission ignored APCo and WPCo's unexpected shortfall of coal during this time and constraints on getting additional coal contracts to make up for such shortfall.

94. The only reason APCo and WPCo would have had enough coal on hand to take advantage of PJM's unexpected high prices would have been to follow the 69% Directive.

95. As seen in various statements made in Commission filings and live and written testimony, APCo and WPCo did not and do not want to follow the 69% Directive but rather want to follow the principles of Economic Dispatch.

96. The Commission's January 2024 Order denying cost recovery is another strong signal to APCo and WPCo that its cost recovery will continue to be denied if it does not follow the 69% Directive, which means it would need to secure enough coal to run at a 69% capacity factor.

The 69% Directive Ignores Economic Dispatch and Thus Harms Ratepayers

97. The Commission has assumed that it is economical for APCo and WPCo to run at a 69% capacity factor; however, it is not economical for APCo and WPCo to run their coal-fired power plants at such a high capacity factor.

98. According to the Energy Information Administration ("EIA"), the annual capacity factor across U.S. coal power plants has not exceeded 50% since 2018. *See* Electric Power Monthly, EIA, available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a (last accessed July 8, 2024).

99. Further, the 10-year average capacity factor for coal units in PJM is 41.9% and was at its highest level in the past decade—50.2%—in 2014. *See* APCo Appellate Br. at 6 n.6.

100. *APCo's historical capacity factors*. According to data sourced from the Environmental Protection Agency's Continuous Emissions Monitoring System (CEMS) and the EIA's monthly and annual Form 923:[1]

a. The average capacity factor over the past seven years for APCo's John E. Amos Unit 1 is 40.18%, with the highest capacity factor being 57.03% in 2017.

b. The average capacity factor over the past seven years for APCo's John E. Amos Unit 2 is 41.9%, with the highest capacity factor being 53.97% in 2017.

c. The average capacity factor over the past seven years for APCo's John E. Amos Unit 3 is 43.51%, with the highest capacity factor being 55.46% in 2018.

d. The average capacity factor over the past seven years for APCo's Mountaineer Unit 1 is 54.85%, with the highest capacity factor being 72.55% in 2019.

101. *WPCO's historical capacity factors*. According, again, to CEMS and Form 923 data:

a. The average capacity factor over the past seven years for WPCo's Mitchell Unit 1 is 31.5%, with the highest capacity factor being 46.49% in 2017.

b. The average capacity factor over the past seven years for WPCo's Mitchell Unit 2 is 38.31%, with the highest capacity factor being 65.76% in 2017.

1 CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

102. APCo and WPCo repeatedly raised concerns with the Commission that they would have to uneconomically dispatch its coal-fired power plants to meet the 69% Directive:

a. On March 14, 2022, John J. Scalzo, APCo's Vice President for Regulatory Services and Finance, submitted the following pre-filed testimony on behalf of APCo and WPCo in the 2021 ENEC case:

> In making their recalculations, the Companies assumed that the additional tons of coal necessary to achieve a 69% capacity factor would cost at least $75 more per ton than embedded coal costs and further assumed that those additional tons would be available. This recalculation shows increased WV ENEC costs of approximately $27.2 million compared to economic dispatch.
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> * * *
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> As shown in Table 2 above, running the Companies' coal-fired units out of merit, in order to achieve a 69% (or higher) capacity factor, assuming coal is even available, will result in increased costs to customers. The Companies need clarification from the Commission that they are being ordered to "selfschedule" units to run when they otherwise would not be dispatched by PJM and, if so, under what parameters are the Companies to engage in such 'self-scheduling.' Furthermore, the Companies need assurance from the Commission that any cost premiums incurred as a result of self-scheduling can be recovered fully from West Virginia ratepayers, as it is very unlikely that regulators in other jurisdictions will approve any such higher-than-necessary costs.

b. During a March 23, 2022 evidentiary hearing in the 2021 ENEC proceeding, Mr. Scalzo gave the following testimony:

> One of the questions we have is, okay, are we supposed to hit 69 percent, regardless of economic dispatch? Because there's --- some of the other Orders they talk about, you know, hit 69 percent because coal is the economical option. And so it's still --- it's still in our mind, the question is --- is are we operating the plant still in economic dispatch and the plants run the way they do. It's a fundamental question. . . . A. But like you said, we also --- you know, if we're to run at 69 percent, are we to run out of economic dispatch? And if we are, there's additional cost associated with that that other jurisdictions may not pay.

c. Mr. Scalzo testified in support of APCo's and WPCo's April 19, 2022 petition initiating the 2022 ENEC proceeding:

> The Commission's directive that the Companies should be targeting a 69% capacity factor at their coal-fired plants would appear at odds with the flexible, least-cost approach of economic dispatch. This is precisely why the Companies have asked for, and need, express clarification in an order from the Commission as to whether the Companies should abandon the economic dispatch model. The need for such clarification is compounded by the fact that the Companies operate across multiple jurisdictions and, given past precedents, or regulations, or both, the regulators in those jurisdictions almost certainly would not approve any unnecessary, increased costs arising from running the plants contrary to an economic dispatch approach.

d. Mr. Scalzo also offered the following in his September 23, 2023, pre-filed rebuttal testimony in that case:

> Given their overarching responsibility to control costs and the Commission's long-standing adherence to safeguarding the interests of public utility customers as one of the several factors it is statutorily required to consider, the Companies have chosen to assume that economic dispatch is still a controlling concept, unless and until the Commission expressly instructs them to the contrary. With respect to the statements of CAD witnesses Medine and Smith and WVEUG witness Baron regarding the 69% capacity factor, it is surprising they have not clarified, in making those statements, whether they support or oppose the idea of the Companies running their coal-fired units out of economic merit, particularly since the increased costs that would result from operating the units out of economic merit would likely fall upon the West Virginia retail customers they represent.
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> * * *
>
> If APCo and/or WPCo were required to ignore costs in order to achieve a 69% capacity factor at Amos, Mountaineer, or Mitchell, it is doubtful, to say the least, that the Companies' other regulators would grant recovery of excess costs incurred in running the plants out of economic merit. In the event of such disallowance, the Companies trust that this Commission would recognize the need for West Virginia retail customers to shoulder the burden of such excess costs if the Commission requires the Companies to incur them.

e. During an evidentiary hearing on October 5, 2022, for the 2022 ENEC Proceeding, Ruben Moreno, a consultant hired by APCo and WPCo, gave the following testimony:

> It directly has an implication, and it has unintended consequences. Given a case where we are driving to a 69 percent capacity factor and the market price is below the cost of generation, the unintended consequence is that the utility will be selling at a loss. And obviously in a model cost of service, that would be passed on to the consumer. So 69 percent as a concept itself does have a consequence, because of this idea that sometimes the prices are lower and that the utility or the generator may not be cost effective to generate. What do we do in that case?
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> * * *
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> Like I stated earlier, it's not a contradiction. It's just requesting --- mandating a 69 percent capacity factor has unintended consequences that eventually will impact the cost. We just need to be upfront in terms of saying, how are we going to handle those?

f. During that same evidentiary hearing on October 5, 2022, Mr. Scalzo testified:

> And so we're seeking clarification of around --- you know, is it run 69 percent when it's economic to do so? Is it run 69 percent when --- at all costs? You know, we just need further clarification. Just like Mr. Baron said, you may uncover uneconomic dispatches. Mr. Moreno said there might be unintended consequences. We need clear direction, kind of like I laid out in my testimony is --- what are the parameters? Is it --- are we to run with 69 percent if it's economical or is it to run regardless of cost? And if it runs regardless of cost, I have issues with trying to recover those out-of-market costs in other jurisdictions.
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> * * *
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> And it's questionable if we could even --- if we ran the plants at a 69 percent capacity factor out of merit, it's debatable whether I'd even ask for that cost recovery from Virginia. And then sitting in the ENEC hearing last week, they're not going to cover that cost. And so that's why we've been asking for clarification. If we run it --- if you want to run it at 69 percent capacity factor, you know, regardless of cost, there is a cost to both jurisdictions that Virginia and Kentucky are probably not going to pay and our FERC customers.

> And so we would need to recover that from West Virginia. So that's why we've been asking for clarification. Like Mr. Moreno said, there's unintended consequences.

g. In pre-filed direct testimony filed by APCo and WPCo in response to the CTC Report on July 28, 2023, Jeff Plewes, the Principal of Charles River Associates—a third-party consultant APCo and WPCo retained to rebut the CTC report—testified on behalf of the Companies as follows:

> It is clear that, from late 2021 through most of 2022, a 69% capacity factor could have been met economically if the Companies hypothetically had unlimited coal supplies at historical prices. In 2023, however, economics have not supported capacity factors of 69%. Artificially forcing a 69% or above capacity factor would have been costly for customers. The following is a simple calculation of the magnitude of costs.
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> * * *
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> If instead of running economically in 2023 the plants had forced capacity factors of 69%, inclusive of outages, there would have been significant costs to customers. As it turns out, for the first six months of 2023, to meet a 69% capacity factor the units would have all needed to run at maximum output (100%) in every hour that they were not in outage. This would have resulted in a 68.6% capacity factor. Interestingly, this suggests that a 69% capacity factor was not even achievable in that timeframe given outages.

h. On September 5, 2023, during the first day of a three-day hearing regarding the 2021, 2022, and 2023 ENEC proceedings, Mr. Plewes testified on behalf of APCo and WPCo as follows:

> What I'm saying on page 14, extended to page 15, is that I thought it was not appropriate to evaluate efforts to meet a 69 percent target. And I said that's not the appropriate focus of a prudency review. I think a prudency review should be evaluating the company's decisions to provide least cost and reliable service to its customers and making decisions based on information available at the time that was reasonable --- and all of this can be inferred ad nauseam in this record. Looking at whether or not they were aiming for a 69 capacity factor target is not what I think should be the focus of a prudency review. I believe the prudency review should be focused on the

> decisions that were made in relation to were they doing what was reasonable based on reasonable information. And I don't think that you run to a set capacity factor. I've explained why I think that that is --- that very likely could be deemed very imprudent without a specific mandate to meet a specific capacity factor. Because if you do that, if you aim and put all your efforts into meeting a 69 percent targeted capacity factor and you successfully achieve your 69 percent target capacity factor in 2023, you have cost your consumers a lot of money.

103. APCo's and WPCo's concerns of uneconomic dispatch were never taken seriously by the Commission; instead, the Commission and its Staff kept assuming that a 69% capacity factor would be economic even when the national, PJM, and APCo's and WPCo's[2] own average historical capacity factors in the past decade were far below such levels.

104. For example, at the October 5, 2022 evidentiary hearing, Staff witness Geoffrey Cooke was being cross examined and testified as follows:

> Q: So let me try to rephrase. Does Staff support customers paying the cost to run the plants --- the coal fired power plants, at 69 percent capacity factor even if running the plant is uneconomical at 69 percent capacity factor?
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> A: I really haven't thought much about that because it seems to appear that the 69 percent is going to be economic. There hasn't been any reason why it's assumed that its not. It would if the parties hadn't said that it could be. There has to be, you know, have to be vague where they run the numbers or something and they come up and it's okay, it's actually X amount over, you know, economically ---.
>
> Q: So you haven't considered the situation where it'd possibly be uneconomic to run at 69 percent? That's not something you considered?
>
> A: No, I have not.

2 Since at least 2004, APCo and WPCo's capacity factors have been the result of market pricing in PJM.

105. The Commission Staff are incorrect that APCo and WPCo, in general, can run at a 69% capacity factor economically. If they were correct, APCo and WPCo would have achieved that capacity factor through the normal market process within PJM.

106. The Commission and Staff assumptions are based on faulty logic and hindsight—while today the Commission is seeing that there were high PJM prices in 2021 and 2022 and APCo and WPCo had costs lower than the Market-Clearing price, the Commission ignores that APCo and WPCo did not have enough coal on hand to take advantage of those prices and had no way of knowing ahead of time that it would have a need to procure additional coal to take advantage of high PJM prices (or that it would have a coal shortfall from a breach of contracts with its coal supplier).

107. APCo and WPCo already have an incentive to procure enough coal to dispatch when it is economic to do so, since they would make a profit from economically dispatching.

108. APCo and WPCo also already have incentive to actually use this coal and run their coal-fired power plants as much as possible when it is economical to do so, thereby generating a profit.

109. APCo and WPCo do not need the 69% Directive or any other capacity factor mandate from the Commission to run their coal-fired power plants as much as possible when it is economic to do so.

110. If APCo runs its power plants when it is uneconomical to comply with the 69% Directive, it risks denial of cost recovery in Virginia's analog to the ENEC proceedings. The Virginia SCC would rightfully question why ratepayers in Virginia should have to pay for uneconomic coal procurement and plant dispatch under the 69% Directive, when APCo could have instead bought energy off the PJM market to serve their customers at a lower cost.

111. In fact, the Virginia SCC has already cautioned APCo that it will not be reimbursed for uneconomic dispatch to meet the 69% Directive. *See supra* par. 102(f) (Mr. Scalzo's testimony from October 5, 2022).

112. In summary, if APCo and WPCo could run at a 69% capacity factor economically, they would already be doing so without the need for the 69% Directive. Because the Directive ignores the principles of economic dispatch, it has and will continue to harm ratepayers, who will shoulder the extra costs associated with the uneconomic dispatch.

The 69% Directive Interferes with PJM's Operations

113. The 69% Directive also interferes with PJM's operations and its objective to set just and reasonable rates.

114. Representatives for APCo and WPCo raised this issue with the Commission, to no avail. For example, Aaron Sink—general manager of Amos—gave the following testimony during the October 4, 2022 evidentiary hearing for the 2022 ENEC proceedings:

> Q: Understood. Mr. Sink, can we --- are you familiar with the Commission directive to try to operate at 69 percent capacity factor?
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> A: I am.
>
> Q: And the fact that it was first initiated by an Order on September 2nd, 2021?
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> A: I'm generally aware of the issue. The only thing that I would add is, you know, from a power plant perspective if that capacity factor's a lagging indicator. We don't control that. It's a look back.
>
> Q: Uh-huh (yes).
>
> A: It's influenced by the way PJM dispatches it. So for us to say, hey, we're going to operate at 69 percent, that's somewhat foreign to me, although I recognize the Commission's views on the subject.

*   *   *

> A: I call it a lookback because I can't --- any plant manager can't walk up to the control room and say, give me 69 percent of the load that's the maximum ---. We just don't do that. We take our load or our dispatch signal from our dispatcher for PJM. PJM essentially says, here's where we want you to go day in and day out, hour by hour. And that output of the unit affects that capacity factor number. So I don't have any influence on that locally at the plant. It's determined by our bids, our offers, and I get those day --- so I know a day ahead of time what I think the unit's going to do, but I don't know in real time what it actually does. And so I look backwards.
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> * * *
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> A: I don't know, because it's --- what I do know is it's a market offer. It's based on, you know, lowest available generation gets dispatched first. What I can say, and that's why I referenced it in my testimony, I'm sorry, Mr. Zwick's testimony which he provided the capacity factors for June, July and August of '21, which I believe was prior to the Commission's Order of 69 percent, and it happened naturally. You know, on page six of his testimony, you know, 69.74, 73.75, and 72.78, that occurred in real time prior to this issue of 69 percent.

115. In order for APCo and WPCo to maintain a 69% capacity factor, they would have to submit artificially low bids to ensure PJM accepted them or self-select operation rather than submit a bid based on their true costs of operation. APCo and WPCo would then receive that day's clearing price for the energy they produce, regardless of whether that price exceeds the costs to APCo and WPCo of dispatching their coal plants.

116. Based on the Commission's presumption of reasonableness at a 69% capacity factor, the costs incurred by APCo and WPCo, as a result of those artificially low bids, would be recovered from ratepayers.

APCo Was Dispatching Uneconomically in 2023 and Is Dispatching Near a 69% Capacity Factor in 2024

117. Upon information and belief, APCo was uneconomically dispatching its coal-fired power plants in 2023, likely due to securing expensive coal contracts in 2022 in response to the Commission's continued hostility over APCo's low capacity factors.

118. Specifically, APCo's John Amos plant appears to have lost approximately $40 million[3] in net energy revenues in 2023 relative to market energy by running in hours where other generating units could have consistently provided power at a lower cost (as realized through the Market-Clearing price of energy).

119. In brief periods in 2023, market prices jumped, temporarily providing the potential for large profits. Amos attempted to capitalize on these periods, but then reverted to net losses in almost all other hours.

120. Specifically, in April 2023, Amos appears to have attempted to capture brief periods of profitability but those periods of profitability were not often enough to offset ongoing losses from continued operations.

121. The singular profitable month for all Amos units was in July 2023, when daily prices rose briefly above the marginal cost of energy, and two high-cost days resulted in profit. These gains offset losses for that month.

122. Upon information and belief, APCo's uneconomic dispatch of Amos in 2023 is to comply with the 69% Directive. For example, the Commission explicitly told APCo in its February 3, 2023 Order that it should run uneconomically during some hours of the day in order to take advantage of higher prices later in the day. That is what APCo is doing, but, as explained above,

3 Variance potential in this estimate is based on hub vs. specific location Locational Marginal Pricing (which is derived from the Market-Clearing price), cost of variable O&M, and the realization of timing of coal costs.

the higher prices realized during certain hours of the day have generally not offset the losses APCo has incurred in other hours in which its plants must dispatch to meet a 69% capacity factor.

123. Further, APCo's Mountaineer unit fired at a roughly 63.4% capacity factor in the first quarter of 2024 and an 64.5% capacity factor in the second quarter of 2024.[4] Upon information and belief, the Mountaineer unit was unable to reach this capacity factor economically and only did so in an effort to comply with the 69% Directive.

124. APCo and WPCo have also admitted in recent 2024 ENEC filings that they have been running units uneconomically—using "Must Run" designations and price discounts—in 2023 and 2024 in response to excess coal supplies, which resulted in over $80 million in operational losses.

125. Because the costs necessary to comply with the 69% Directive have and will continue to exceed the revenues generated thereunder, West Virginia's ratepayers will unfairly subsidize this uneconomic dispatch.

4 According to data APCo reported to the EPA available through EPA's Clean Air Markets Program Data, APCo's Mountaineer plant had a gross load of 1,827,544.7 MWh in Quarter 1 of 2024 (January 1, 2024, through March 31, 2024) and 1,860,922.82 in Quarter 2 of 2024 (April 1, 2024, to June 30, 2024). According to the CTC Report, Mountaineer has a capacity of 1,320 MW. Multiplying this capacity by the number of hours in Quarter 1 and 2 of 2024 (which is 2,184 hours each Quarter) equals 2,882,880 MW, which is the maximum amount of MW APCo's Mountaineer plant could have generated in Quarter 1 and Quarter 2 of 2024. Dividing the amount Mountaineer actually generated in Quarter 1 and Quarter 2 by the maximum results in a 63.4% capacity factor in Quarter 1 and a 64.5% capacity factor in Quarter 2.

CLAIMS FOR RELIEF

COUNT I

(Violation of the Supremacy Clause, U.S. Constitution, art. VI, cl. 2)

126. Plaintiffs restate and incorporate by reference each and every allegation in Paragraphs 1 through 125 as if fully set forth herein.

127. The Commission has the exclusive authority to set retail rates. However, the Commission does not have unlimited authority over public utilities. *See Lumberport-Shinnston Gas Co. v. Public Service Commission of West Virginia*, 271 S.E.2d 438, 443 (W. Va. 1980) ("[T]he PSC is not to be seen as a super board of directors for the public utility companies of the State . . . .").

128. While the Commission has exclusive jurisdiction over retail rates, FERC has exclusive power in regulating wholesale rates and the wholesale market, and FERC must ensure such rates are "just and reasonable." *See* 16 U.S.C. § 824d(a).

129. Rather than ensuring the reasonableness of interstate transactions by directly setting rates, FERC has chosen instead to achieve its regulatory aims indirectly by protecting "the integrity of the interstate energy markets." *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 81 (3d Cir.2014).

130. FERC ensures these "just and reasonable" wholesale rates by enhancing competition—attempting "to break down regulatory and economic barriers that hinder a free market in wholesale electricity." *Morgan Stanley Capital Group Inc. v. Public Util. Dist. No. 1 of Snohomish Cnty.*, 554 U.S. 527, 536 (2008).

131. FERC extensively regulates the structure of these competitive markets to ensure that they efficiently balance supply and demand, producing a just and reasonable clearing price. *See EPSA*, 577 U.S. at 268 (the clearing price is "the price an efficient market would produce").

132. Under the Supremacy Clause of the United States Constitution, a state law is preempted when Congress intends federal law to occupy the field (field preemption), as well as in cases where the state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress (conflict preemption).

133. "The FPA leaves no room either for direct state regulation of the prices of interstate wholesales or for regulation that would indirectly achieve the same result." *EPSA*, 577 U.S. at 288 (internal quotation marks omitted).

134. *The 69% Directive Is Preempted.* The 69% Directive compels APCo and WPCo to achieve a particular outcome—a 69% capacity factor for its coal-fired power plants—which is higher than they would otherwise achieve under principles of Economic Dispatch. Because APCo and WPCo must sell all the power they generate into PJM, the 69% Directive compels APCo and WPCo to reach this outcome by bidding into and clearing the PJM energy market for a substantial percentage of the year. Thus, the 69% Directive creates a "bid-and-clear" requirement that aims at regulating APCO and WPCo's participation in the wholesale market—a matter firmly within FERC's exclusive authority—and is therefore preempted under binding precedent. *See Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 166 (2016) (striking down State program under preemption because it tethered payment on bidding into and clearing the wholesale market, which is purely FERC's jurisdiction); *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); *see also Rochester Gas & Elec. Corp. v. Pub. Serv. Comm'n of State of N.Y.*, 754 F.2d 99, 102 (2d Cir. 1985); *Coalition for Competitive Electricity v. Zibelman*, 906 F.3d 41, 52 (2d Cir. 2018) ("What mattered in *Rochester Gas* was whether the retail rate adjustment, which factored in expected wholesale revenues, intruded on FERC's jurisdictional turf by compelling

wholesale market participation."); *Allco Fin. Ltd. v. Klee*, 861 F.3d 82, 97 (2d Cir. 2017) (arguing that "[c]ompelling a wholesale transaction—one that would not have taken place but for the State's compulsion—plainly involves the regulation of wholesale sales and thus falls squarely within the field that Congress has occupied" in the FPA).

135. Plaintiffs have no adequate remedy at law and no opportunity for compensation for the Order's violation of the Supremacy Clause because the Commission has sovereign immunity for damages.

136. Plaintiffs will suffer irreparable harm by the violation of the Supremacy Clause, because the Commission's interference with the wholesale interstate electricity markets will cause Plaintiffs, and ratepayers at large, to sustain economic losses. As APCo and WPCo alter their behavior and dispatch their coal units uneconomically to comply with the PSC's directive, Plaintiffs—as ratepayers—will have to subsidize APCo's and WPCo's uneconomic dispatch.

137. The public interest will be harmed by the violation of the Supremacy Clause because the Order frustrates Congress's desire to place regulation of wholesale electricity sales under the exclusive purview of FERC. Additionally, all West Virginia ratepayers served by APCo and WPCo will be required to pay for the uneconomic dispatch of coal as a result of the 69% Directive.

138. Plaintiffs are entitled to judgment under 28 U.S.C. §§ 2201(a) and 2202, declaring that the 69% Directive violates the Supremacy Clause (Article VI, Clause 2) of the United States Constitution.

139. Plaintiffs also are entitled for this reason to injunctive relief preventing the Commission from requiring APCo and WPCo to run at 69% capacity or any other capacity factor percentage, regardless of the economics.

PRAYER FOR RELIEF

Plaintiffs respectfully request that the Court:

1. Declare that the 69% Directive violates the Supremacy Clause of the United States Constitution;

2. Enjoin Defendants from executing or otherwise putting into effect the 69% Directive, including denying cost recovery for failure to dispatch at any arbitrary capacity factor when such dispatch is uneconomic;

3. Award Plaintiffs their attorney fees and costs, if appropriate; and

4. Award Plaintiffs such further relief as the Court may deem just and equitable.

Dated: August 20, 2024

Respectfully submitted,

/s Amanda Demmerle

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