Supreme Court of Ohio Clerk of Court - Filed May 18, 2016 - Case No. 2014-1505

IN THE SUPREME COURT OF OHIO

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan.	:	Supreme Court Case No. 2014-1505
In the Matter of the Application of The Dayton Power and Light Company for Approval of Revised Tariffs.	:	Appeal from the Public Utilities Commission of Ohio
In the Matter of the Application of The Dayton Power and Light Company for Approval of Certain Accounting Authority.	:	Public Utilities Commission of Ohio Case Nos. 12-426-EL-SSO, 12-427-EL-ATA, 12-428-EL-AAM, 12-429-EL-WVR, and 12-672-EL-RDR
In the Matter of the Application of The Dayton Power and Light Company for Waiver of Certain Commission Rules.	:	
In the Matter of the Application of The Dayton Power and Light Company to Establish Tariff Riders.	:	
Industrial Energy Users-Ohio, Appellant, v. Public Utilities Commission of Ohio, Appellee.	:	

NOTICE OF ADDITIONAL AUTHORITY

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NOTICE OF ADDITIONAL AUTHORITY

Under the authority of Supreme Court Rule of Practice 17.08, Industrial Energy Users-Ohio provides notice of its intent to rely during oral argument on the following decisions:

> *In re Application of Columbus S. Power Co.,* Slip Op. 2016-Ohio-1608 (Apr. 21, 2016) (Attachment A);

Hughes v. Talen Energy Marketing, LLC, Slip Op., (U.S. Sup. Ct. Apr. 19, 2016) (Attachment B);

Federal Energy Regulatory Commission v. Electric Power Supply Association, Slip Op. (U.S. Sup. Ct. Jan. 25, 2016) (Attachment C).

Copies of the decisions are attached.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Notice of Additional Authority* was served upon the parties of record *via* electronic transmission this 18th day of May 2016.

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ATTACHMENT A

NOTICE

This slip opinion is subject to formal revision before it is published in an advance sheet of the Ohio Official Reports. Readers are requested to promptly notify the Reporter of Decisions, Supreme Court of Ohio, 65 South Front Street, Columbus, Ohio 43215, of any typographical or other formal errors in the opinion, in order that corrections may be made before the opinion is published.

SLIP OPINION NO. 2016-OHIO-1608

IN RE APPLICATION OF COLUMBUS SOUTHERN POWER COMPANY AND OHIO POWER COMPANY FOR AUTHORITY TO ESTABLISH A STANDARD SERVICE OFFER UNDER R.C. 4928.143 IN THE FORM OF AN ELECTRIC SECURITY PLAN; THE KROGER COMPANY ET AL., APPELLANTS AND CROSS-APPELLEES; OHIO POWER COMPANY, D.B.A. AEP OHIO, APPELLEE AND CROSS-APPELLANT; PUBLIC UTILITIES COMMISSION, APPELLEE AND CROSS-APPELLEE.

[Until this opinion appears in the Ohio Official Reports advance sheets, it may be cited as *In re Application of Columbus S. Power Co.,* Slip Opinion No. 2016-Ohio-1608.]

Public utilities—Electric-security plan—Commission's orders approving modified electric-security plan—Retail stability rider—R.C. 4928.143(B)(2)(d)—Commission erred in approving RSR—RSR allows collection of unlawful transition revenue—Orders reversed in part and cause remanded.

(No. 2013-0521—Submitted May 19, 2015—Decided April 21, 2016.)

APPEAL and CROSS-APPEAL from the Public Utilities Commission, Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM.

KENNEDY, J.

SUMMARY

{¶ 1} This cause arises from the Public Utilities Commission's modification and approval of the second electric-security plan of the American Electric Power operating companies, Ohio Power Company and Columbus Southern Power Company.[1] The case below was a major proceeding in which the commission authorized new generation rates for the companies (collectively, "AEP"). Five parties appealed.[2] AEP also filed a cross-appeal. In total, the remaining parties have raised eight propositions of law that challenge various elements of the commission's orders (the original order and two entries on rehearing) approving the modified electric-security plan.

{¶ 2} After review, we conclude that the parties have demonstrated two errors: one on appeal and one on cross-appeal. Therefore, for the reasons that follow, we affirm the commission's orders in part and reverse them in part and remand the cause for further consideration.

FACTS AND PROCEDURAL BACKGROUND

{¶ 3} R.C. 4928.141(A) requires electric-distribution utilities to make a "standard service offer" of generation service to consumers in one of two ways:

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[1] According to a document filed with the Securities and Exchange Commission on January 6, 2012, Columbus Southern Power Company and Ohio Power Company merged on December 31, 2011, with Ohio Power Company as the surviving entity. *See* https://www.aep.com/investors/financialfilingsandreports/filings/HTMLView.aspx?ipage=7988106. The merger was approved by the Ohio Public Utilities Commission in *In re Application of Ohio Power Co. for Auth. to Merge,* Pub. Util. Comm. No. 10-2376-EL-UNC, *56-57 (Dec. 14, 2011).

[2] FirstEnergy Solutions and Industrial Energy Users-Ohio dismissed their appeals, leaving three appellants. *See* 139 Ohio St.3d 1475, 2014-Ohio-3028, 11 N.E.3d 1196; 144 Ohio St.3d 1436, 2015-Ohio-5451, 42 N.E.3d 770.

through a "market-rate offer" (under R.C. 4928.142) or an "electric security plan" (under R.C. 4928.143). The market-rate offer, as the name implies, sets rates using a competitive-bidding process to harness market forces.

{¶ 4} On January 27, 2011, AEP filed an application with the commission, seeking approval of an electric-security plan ("ESP"). R.C. 4928.143 does not provide a detailed mechanism for establishing rates under an ESP. Plans may contain any number of provisions in a variety of categories so long as the plan is "more favorable in the aggregate" than the expected results of a market-rate offer. R.C. 4928.143(C)(1). But the law does contain certain limits, some of which are at issue in this case.

The Commission's "Capacity Case" Order

{¶ 5} The ESP case proceeded along a parallel—and for a time a consolidated—path with Pub. Util. Comm. No. 10-2929-EL-UNC (the "Capacity Case"). The Capacity Case was argued before the court on December 15, 2015 (case Nos. 2012-2098 and 2011-0228). On December 30, 2015, the court issued an order holding this case for a joint release with the Capacity Case. *See* 144 Ohio St.3d 1438, 2015-Ohio-5468, 43 N.E.3d 450.

The Commission's ESP Order

{¶ 6} In the order under review in this appeal, the commission approved AEP's modified ESP. Pub. Util. Comm. Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM (Aug. 8, 2012) (the "ESP Order"). As part of the ESP, the commission approved a mechanism called the "Retail Stability Rider" ("RSR"). The RSR is "nonbypassable," meaning that it is paid by both shopping and nonshopping customers in AEP's service territory.

{¶ 7} The RSR serves two purposes. First, the commission determined that the RSR would be used as the mechanism for AEP to recover its deferred capacity costs from the Capacity Case. The commission authorized AEP to recover a portion of those deferred costs during the ESP period. The commission

further instructed AEP to file an application after the ESP ends that, if approved, would allow the company to recover any remaining deferred capacity costs, starting on June 1, 2015, and continuing over the following 32 months.

{¶ 8} Second, in addition to serving as the mechanism to recover deferred capacity costs, the RSR was intended to provide AEP with sufficient revenue to maintain its financial integrity and ability to attract capital during the ESP. According to the commission, the RSR was authorized under R.C. 4928.143(B)(2)(d) as a charge that promotes stable retail-electric-service prices and ensures customer certainty regarding retail electric service. ESP Order at 31-38.

{¶ 9} Appeals of the ESP Order were filed by the Kroger Company, the Office of the Ohio Consumers' Counsel ("OCC"), and the Ohio Energy Group. AEP filed a cross-appeal. The appellants primarily challenge the commission's authorization of the RSR. In AEP's cross-appeal, the company contends that the commission erred in setting the threshold for the significantly-excessive-earnings test and also violated the company's statutory right to withdraw the modified ESP.

STANDARD OF REVIEW

{¶ 10} "R.C. 4903.13 provides that a PUCO order shall be reversed, vacated, or modified by this court only when, upon consideration of the record, the court finds the order to be unlawful or unreasonable." *Constellation NewEnergy, Inc. v. Pub. Util. Comm.*, 104 Ohio St.3d 530, 2004-Ohio-6767, 820 N.E.2d 885, ¶ 50. We will not reverse or modify a PUCO decision as to questions of fact when the record contains sufficient probative evidence to show that the commission's decision was not manifestly against the weight of the evidence and was not so clearly unsupported by the record as to show misapprehension, mistake, or willful disregard of duty. *Monongahela Power Co. v. Pub. Util. Comm.*, 104 Ohio St.3d 571, 2004-Ohio-6896, 820 N.E.2d 921, ¶ 29. The

appellant bears the burden of demonstrating that the commission's decision is against the manifest weight of the evidence or is clearly unsupported by the record. *Id.*

{¶ 11} Although this court has "complete and independent power of review as to all questions of law" in appeals from the commission, *Ohio Edison Co. v. Pub. Util. Comm.*, 78 Ohio St.3d 466, 469, 678 N.E.2d 922 (1997), we may rely on the expertise of a state agency in interpreting a law where "highly specialized issues" are involved and "where agency expertise would, therefore, be of assistance in discerning the presumed intent of our General Assembly." *Consumers' Counsel v. Pub. Util. Comm.*, 58 Ohio St.2d 108, 110, 388 N.E.2d 1370 (1979).

DISCUSSION

The Appeals of Appellants: OCC, Kroger, and Ohio Energy Group

{¶ 12} The appellants, taken together, raise five propositions of law, each containing several supporting arguments. The issues involving the RSR are the most prominent and generally relate to each other, so we will discuss them first.

I. Challenges to the commission's approval of the RSR

{¶ 13} The appellants raise several challenges to the commission's approval of the RSR. After review, we find that one argument has merit.

A. *OCC Proposition of Law No. 2*: Whether the commission's order is unlawful or unreasonable because it allows the company to collect unlawful transition revenue or its equivalent through the RSR

{¶ 14} OCC argues that the commission erred in approving the RSR because it permits AEP to recover unlawful "transition revenues" in the form of nonfuel generation revenues, including capacity revenues, that it will lose under its ESP. OCC claims that because the statutory time period to recover transition revenue has ended, the commission lacked authority to approve the RSR, since it

allowed the company to recover costs that are otherwise unrecoverable in the competitive generation market. We find this argument well taken.

1. What is transition revenue, and when was its recovery barred?

{¶ 15} Transition costs (also referred to as stranded costs) are costs incurred by the utility before retail competition began that will not be recoverable through market-based rates. *See FirstEnergy Corp. v. Pub. Util. Comm.*, 95 Ohio St.3d 401, 2002-Ohio-2430, 768 N.E.2d 648, ¶ 14; R.C. 4928.37 and 4928.39. In general, these are generation costs that the utility incurred to serve its customers that would have been recovered through regulated rates before competition began, but that are no longer recoverable from customers who have switched to another generation provider. *See Toledo v. Toledo Edison Co.*, 118 Ohio Misc.2d 131, 2000-Ohio-2696, 770 N.E.2d 132, ¶ 18-19, citing *Transm. Access Policy Study Group v. Fed. Energy Regulatory Comm.*, 225 F.3d 667, 683, 699-700 (D.C.Cir.2000). When such customers leave the utility's generation service, they may not have paid their share of costs that the utility incurred on their behalf. The idea behind transition revenue is to allow the utility to avoid having to either absorb these costs or shift the burden of recovery onto remaining customers. *Id.* at ¶ 22.

{¶ 16} In 1999, the General Assembly enacted Am.Sub.S.B. No. 3 ("S.B. 3"), 148 Ohio Laws, Part IV, 7962, "to facilitate and encourage development of competition in the retail electric market." *AK Steel Corp. v. Pub. Util. Comm.*, 95 Ohio St.3d 81, 765 N.E.2d 862 (2002). Enacted as part of S.B. 3, R.C. 4928.37 provided each electric utility with a limited opportunity "to receive transition revenues that may assist it in making the transition to a fully competitive retail electric generation market." Utilities had until December 31, 2005 (the end of the market-development period, *see* R.C. 4928.01(A)(26)) to receive generation transition revenue. R.C. 4928.38 and 4928.40(A). Utilities were also permitted to receive transition revenue associated with regulatory assets (i.e., deferred charges,

see R.C. 4928.01(A)(26)) until December 31, 2010. R.C. 4928.40(A). After that date, R.C. 4928.38 prohibits the commission from "authoriz[ing] the receipt of transition revenues or any equivalent revenues by an electric utility," with certain exceptions not applicable here.

{¶ 17} R.C. 4928.141(A), enacted as part of Am.Sub.S.B. No. 221, expressly prohibits the recovery of transition costs by providing that a standard service offer made through an ESP "shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the utility's rate plan."

2. The commission's order on the subject of transition costs is unlawful and unreasonable

{¶ 18} As noted, R.C. 4928.38 bars the commission from authorizing the "receipt of transition revenues or any equivalent revenues" after December 31, 2010. OCC maintains that the commission violated this provision when it guaranteed that AEP will receive $826 million in nonfuel generation revenues through the RSR in each year of the ESP. OCC argues that the RSR cannot be upheld because it allows the company to receive transition revenue or "equivalent" revenues that are no longer authorized in the competitive generation market after the deadlines in R.C. 4928.38 and 4928.40.

{¶ 19} In the orders below, the commission found that AEP was not receiving unlawful transition revenue through the RSR. The commission offered two reasons to support its finding. After review, we find that neither one is well taken.

a. The fact that AEP did not expressly seek transition revenues in this case does not defeat a claim that it is recovering transition revenues

{¶ 20} The commission first found that AEP was not receiving unlawful transition revenue because the company did not seek transition revenues in its modified ESP application. ESP Order at 32; First Rehearing Entry at 21 (Jan. 30,

2013). According to the commission, AEP is not receiving transition revenues or recovering stranded costs through the RSR, since AEP did not argue that the revenues received under its prior electric-transition plan were insufficient to cover costs. ESP Order at 32.

{¶ 21} But the fact that AEP did not explicitly seek transition revenues does not foreclose a finding that the company is receiving the equivalent of transition revenue under the guise of the RSR. The commission's overly narrow definition of transition revenue overlooks that R.C. 4928.38 bars "the receipt of transition revenues *or any equivalent revenues* by an electric utility" after 2010. (Emphasis added.) By inserting the phrase "any equivalent revenues," the General Assembly has demonstrated its intention to bar not only transition revenue associated with costs that were stranded during the transition to market following S.B. 3 but also any revenue that amounts to transition revenue by another name. Therefore, we find that the commission erred in focusing solely on whether AEP had sought to receive transition revenues that are now barred.

{¶ 22} Further, after looking at the nature of the revenue recovered under the RSR, we find that the record supports a finding that AEP is receiving the equivalent of transition revenues through that rider. As noted above, S.B. 3 allowed electric utilities to receive transition revenues to aid them in making the transition to a fully competitive generation market. R.C. 4928.37(A)(1). *See FirstEnergy Corp. v. Pub. Util. Comm.*, 95 Ohio St.3d 401, 2002-Ohio-2430, 768 N.E.2d 648, ¶ 14 (transition revenues represent regulatory assets and other generation costs that were incurred by the utility under regulation that would not be recovered in a competitive environment); *Toledo v. Toledo Edison Co.*, 118 Ohio Misc.2d 131, 2000-Ohio-2696, 770 N.E.2d 132, ¶ 19 (C.P.) ("stranded costs consist predominately of costs of building generation capacity that utilities incurred with the expectation that they would use the additional capacity to serve existing customers").

{¶ 23} AEP proposed the RSR as a means to ensure that the company was not financially harmed during its transition to a fully competitive generation market over the three-year ESP period. To be more specific, the RSR was intended to guarantee recovery of lost revenue resulting from certain discounted capacity prices offered to CRES providers and from expected increases in customer shopping during the ESP. According to the company's witnesses, the RSR was designed to generate enough revenue for the company to achieve a certain rate of return on its generation assets as it transitions to full auction pricing for energy and capacity by June 2015. ESP Order at 31-32.

{¶ 24} In determining how much revenue would be needed to reach the $826 million revenue target for each year, the commission focused on three categories of revenue: retail nonfuel generation revenues, CRES capacity revenues, and credit for shopped load. In calculating these revenue amounts, the commission relied on shopping projections for AEP's service territory during the three-year ESP period. That is, the shopping projections would determine a combined amount of revenue that AEP would earn for each category listed above, and the RSR would be set at the amount necessary to boost the total to the revenue target of $826 million. Importantly, the commission's calculations show that RSR revenues were tied in large part to CRES capacity revenues that AEP would expect to lose based on the projected shopping and the below-cost price of capacity charged to CRES providers during the ESP period. ESP Order at 34-35.

{¶ 25} In sum, we find that the commission erred in focusing solely on whether AEP had expressly sought to receive transition revenues rather than looking at the nature of the costs recovered through the RSR. R.C. 4928.38 bars the "the receipt of transition revenues *or any equivalent revenues* by an electric utility." Based on the record before us, we find that the RSR in this case recovers the equivalent of transition revenue and the commission erred when it found otherwise.

b. The commission erred when it found that anything above PJM auction capacity prices cannot be labeled as transition costs or stranded costs

{¶ 26} The commission found that the revenues recovered through the RSR were lawful because AEP was entitled to recover its "actual costs of capacity." AEP's capacity charge is higher than the auction price of capacity in the PJM region. According to the commission, because AEP is the sole provider of capacity service in its territory, "anything over" PJM auction capacity prices "cannot be labeled as transition costs or stranded costs." ESP Order at 32. We disagree.

1. The commission's rejection of AEP's two-tiered capacity-pricing mechanism and its determination of an appropriate capacity charge

{¶ 27} At the outset, it is important to understand that AEP had proposed two separate capacity-pricing plans to the commission: one in the Capacity Case and a completely different plan in the ESP Case. The following background is therefore provided to place this issue in proper context.

{¶ 28} Before the commission issued its order in the ESP Case, the commission found in the Capacity Case that AEP was allowed to recover its actual costs to provide capacity to CRES providers. Pub. Util. Comm. No. 10-2929-EL-UNC, at 33 (July 12, 2012). In the Capacity Case, AEP had claimed that a capacity charge of $355.72 per megawatt-day would enable it to fully recover its costs and earn a reasonable return on its investments. *Id.* at 24. The commission rejected that assertion, finding instead that a charge of $188.88 per megawatt-day was sufficient to fairly compensate the company for providing capacity. *Id.* at 33.

{¶ 29} The commission, however, was concerned that AEP's cost-based capacity charge would have a negative impact on retail competition in the company's service territory. As a result, the commission ordered AEP to charge

CRES providers at the PJM auction price during the ESP period, a discount from the commission-ordered cost-based capacity charge of $188.88 per megawatt-day. The commission further ordered in the Capacity Case that AEP defer its recovery of the difference between the discounted capacity charge and the cost-based capacity charge until after the ESP ends. *Id.* at 33-35, 23.

{¶ 30} While the Capacity Case was still pending before the commission, AEP offered a capacity-pricing plan in the ESP Case that was different from the company's litigated position in the Capacity Case. In its modified ESP application, the company proposed to sell capacity to CRES providers at a discount from the $355.72 per megawatt-day price, which is the rate that AEP claimed represented its costs to provide capacity. Under this proposal, AEP would provide capacity to CRES providers under a two-tiered pricing plan, with the tier-one rate set at $145.79 per megawatt-day and the tier-two rate at $255 per megawatt-day. As part of this two-tiered pricing plan, AEP asked the commission to approve the RSR as the mechanism that would enable the company to recover the difference between the discounted capacity sold to CRES providers under the two tiers and what it claimed was its fully embedded costs of capacity (the $355.72 per megawatt-day rate). ESP Order at 50.

{¶ 31} After the commission rejected AEP's capacity charge of $355.72 per megawatt-day in the Capacity Case, it issued the order in the ESP Case. Having found that a capacity charge of $188.88 per megawatt-day would enable AEP to fully recover its capacity costs, the commission rejected the two-tiered pricing mechanism that AEP had proposed in its modified ESP application. The commission, however, approved the RSR in the ESP Case, even though it had been proposed as a component of the now-rejected two-tiered capacity plan. As noted above, with the approval of the RSR, AEP was able to recover an additional $508 million in revenue during the ESP period. *See* ESP Order at 31-32, 35-36.

2. The commission has allowed AEP to recover more than its actual capacity costs through the nondeferral portion of the RSR

{¶ 32} We do not agree with the commission's finding that "anything over" PJM auction capacity prices "cannot be labeled as transition costs or stranded costs." According to the commission, AEP is not receiving unlawful transition revenue through the RSR because AEP is entitled to recover its actual capacity costs based on its status as the sole provider of capacity in its service territory. ESP Order at 21. But the commission ignores that it has allowed AEP to recover *more* than its actual capacity costs through the nondeferral part of the RSR.

{¶ 33} As we note in the preceding section, AEP will recover its actual capacity costs (based on a charge of $188.88 per megawatt-day). AEP will recover its costs in the following manner: (1) charging CRES providers during the ESP period at the PJM auction price (a discount from AEP's cost-based capacity charge of $188.88 per megawatt-day), (2) deferring for later recovery the difference between the discounted charge and AEP's cost-based capacity charge, (3) collecting a portion of the deferred capacity costs during the ESP through the RSR, and (4) collecting any remaining balance of the deferred costs (plus carrying charges) after the ESP period ends. Capacity Case Order at 33-35, 23; ESP Order at 31-38.

{¶ 34} Yet despite the fact that the commission authorized AEP to recover its actual capacity costs, the commission also allowed AEP to recover $508 million in additional revenue through the RSR during the ESP period, the amount of which appears to be tied in large part to AEP's recovery of CRES capacity charges. ESP Order at 34-35. Again, the commission calculated the RSR amount in part based on expected decreases in CRES capacity revenues during the ESP due to (1) the projected level of shopping in AEP's territory and (2) the discounted capacity price (well below AEP's costs) charged to CRES providers.

Thus, the commission awarded AEP additional capacity revenues through the nondeferral portion of the RSR, even though it had found that AEP would fully recover its incurred CRES capacity costs at a rate of $188.88 per megawatt-day. Accordingly, we find that the company is being overcompensated for providing capacity service through the nondeferral part of the RSR.

{¶ 35} Although the commission cited various reasons for approving the RSR, none justifies the additional capacity revenue recovery associated with the RSR. The commission first implied that the RSR was necessary to "ensure [that] AEP-Ohio has sufficient funds to maintain its operations efficiently and revise its corporate structure, as opposed to a deferral only mechanism." ESP Order at 36-37. But the commission found in the Capacity Case that "a capacity charge of $188.88/MW-day, in conjunction with the authorized deferral of the Company's incurred capacity costs," would "reasonably and fairly compensate the Company and should not significantly undermine the Company's ability to earn an adequate return on its investment." 10-2929-EL-UNC, at 36. The ESP Order was issued five weeks after the commission made this finding in the Capacity Case. Yet the commission fails to explain in the ESP Order why, only five weeks later, the cost-based capacity charge and "deferral only mechanism" authorized in the Capacity Case were no longer adequate.

{¶ 36} Second, according to the commission, "no party disputes that the approval of the RSR will provide AEP-Ohio with sufficient revenue to ensure it maintains its financial integrity as well as its ability to attract capital." ESP Order at 31. While no party may have disputed that this was the intended purpose of the RSR, several parties challenged whether the RSR was necessary to achieve that purpose. To be sure, after the commission had determined an appropriate cost-based capacity charge for AEP in the Capacity Case, several parties argued in the ESP Case that the additional revenue generated from the proposed RSR was no longer necessary.

{¶ 37} Beyond the lack of reasoning, we have carefully reviewed the ESP Order and find that it contains no evidence that would support approval of the additional capacity revenue recovered through the RSR under the circumstances presented in this case. *See In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 24-25 (lack of record support for portion of order justifies reversal). The critical problem is that the evidence relied on by the commission to approve the RSR was evidence that AEP had submitted to support the RSR under the two-tiered capacity-pricing plan. But the foundation for the RSR was eliminated when the commission rejected the two-tiered plan and found instead that AEP would be fully compensated for providing capacity under the cost-based charge approved in the Capacity Case. And no evidence was submitted in the ESP Case after the commission issued its decision in the Capacity Case. In short, none of the evidence cited in the ESP Order is relevant to whether it was necessary for AEP to recover additional revenue through the RSR beyond the costs that the company incurred to provide capacity service.

3. Conclusion as to transition-revenue issue

{¶ 38} Based on the foregoing, we find that the commission erred when it found that AEP was not recovering transition revenue or its equivalent through the RSR.[3] The commission's finding that the RSR does not recover unlawful

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[3] R.C. 4928.143(B) provides:

> "Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary except division (D) of this section, divisions (I), (J), and (K) of section 4928.20, division (E) of section 4928.64, and section 4928.69 of the Revised Code:
>
> * * *
>
> (2) The [electric security] plan may provide for or include, without limitation, any of the following [listing nine categories of permissible terms]." The "[n]otwithstanding" provision can be read as creating an exception to the prohibition against transition revenue. But because the commission did not rely on this language in the case below, and no party appears to have raised the issue, we decline to consider it on appeal.

transition revenue lacks sound reasoning and record support. Therefore, it cannot be upheld.

{¶ 39} As to the question of remedy, we note that AEP is currently collecting the deferred capacity costs with carrying charges through the RSR. *In re Application of Ohio Power Co. to Adopt a Final Implementation Plan for the Retail Stability Rider,* Pub. Util. Comm. No. 14-1186-EL-RDR, at 11-12 (Apr. 2, 2015). In addition, in the Capacity Case appeals, we affirmed the commission's decision that AEP is entitled to charge a cost-based state compensation mechanism and that the $188.88 per megawatt-day rate is reasonable.

{¶ 40} Because AEP is entitled to recover only its actual capacity costs, we order the commission to adjust the balance of its deferred capacity costs to eliminate the overcompensation of capacity revenue recovered through the nondeferral part of the RSR during the ESP. However, because of the method employed by the commission to calculate the RSR, we are unable to determine exactly how much of the revenue recovered through the nondeferral part of the RSR is allocable to CRES capacity revenues. We therefore remand this matter to the commission to determine that amount and offset the balance of deferred capacity costs by the amount determined.

B. *Ohio Energy Group Proposition of Law No. 1*: Whether the commission erred in incorporating deferred capacity costs in the RSR and deferring those costs under R.C. 4928.144

{¶ 41} Ohio Energy Group next argues that the commission's order violated R.C. 4928.144 by deferring capacity costs that were approved in the Capacity Case and not as part of the ESP. R.C. 4928.144 provides that the commission "may authorize any just and reasonable phase-in of any electric distribution utility rate or price established under sections 4928.141 to 4928.143 of the Revised Code." According to Ohio Energy Group, because the capacity charges were not established under R.C. Chapter 4928, the commission erred

when it deferred those costs through the RSR for later recovery. We find that this argument lacks merit.

{¶ 42} Ohio Energy Group challenges only the $144 million in revenue that was collected through the RSR to pay down the balance of the deferred capacity costs. But these costs were not deferred; they were collected during the ESP. Therefore, Ohio Energy Group's challenge under R.C. 4928.144 in this context is misplaced.

C. Challenges to the commission's determination that the RSR was authorized under R.C. 4928.143(B)(2)(d)

{¶ 43} In its modified ESP application, AEP sought approval of the nonbypassable RSR under R.C. 4928.143(B)(2)(d). This section states that an ESP may include

> [t]erms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service.

Thus, a proposed item in an ESP is authorized if it meets three criteria: (1) it is a term, condition, or charge, (2) it relates to one of the listed items (*e.g.*, limitations on customer shopping, bypassability, carrying costs), and (3) it has the effect of stabilizing or providing certainty regarding retail electric service. The commission found that the RSR was authorized under this section as a charge that relates to default service, promotes stable retail-electric-service prices, and ensures customer certainty regarding retail electric service. ESP Order at 31-32;

First Rehearing Entry at 15. Appellants raise several challenges to the commission's determination. None have merit.

1. *OCC's Proposition of Law No. 3 (Sections A.1 and A.2)*: Whether the commission failed to apply the statutory definition of "default service" when construing R.C. 4928.143(B)(2)(d)

{¶ 44} OCC first argues that the commission misconstrued the term "default service" in R.C. 4928.143(B)(2)(d) when it approved the RSR. According to OCC, the commission erred when it failed to apply the statutory definition of "default service" set forth in R.C. 4928.14. We find that OCC has forfeited this argument.

{¶ 45} In its First Rehearing Entry on January 30, 2013, the commission decided for the first time that the RSR was authorized under R.C. 4928.143(B)(2)(d) as a charge that relates to default service. OCC filed a second application for rehearing, but it never alleged in its second application that the commission erred when it failed to apply the statutory definition of default service. Instead, it argued that the commission's finding that the RSR related to default service was unsupported by the record and not based on specific findings of fact, thereby violating R.C. 4903.09 and 4903.13.

{¶ 46} R.C. 4903.10 requires the commission's ruling on any particular issue to be challenged through an application for rehearing before that issue can be appealed. OCC may not argue for the first time in this court that the commission's entry violated R.C. 4928.14. It must first raise the issue with the commission, giving the commission an opportunity to correct the alleged error. Because OCC did not give the commission the opportunity to first address this argument, we lack jurisdiction to consider the argument now. *Discount Cellular, Inc. v. Pub. Util. Comm.*, 112 Ohio St.3d 360, 2007-Ohio-53, 859 N.E.2d 957, ¶ 66.

2. *OCC's Proposition of Law No. 3 (Section B)*: Whether the commission erred in concluding that the RSR satisfies R.C. 4928.143(B)(2)(d) without finding that it "directly" stabilizes or provides certainty regarding retail electric service

{¶ 47} OCC also contends that the commission erred in finding that the RSR has "the effect of stabilizing or providing certainty regarding retail electric service," as required by R.C. 4928.143(B)(2)(d). According to OCC, under the plain language of the statute, that effect must be direct. OCC maintains that the commission misconstrued the statute when it found that the RSR could be approved even if it had only an *indirect* effect on retail electric service.

{¶ 48} Our analysis must begin with the language of the statute. *See In re Application of Ohio Power Co.*, 140 Ohio St.3d 509, 2014-Ohio-4271, 20 N.E.3d 699, ¶ 20. R.C. 4928.143(B)(2)(d) does not speak to whether the "effect of stabilizing or providing certainty regarding retail electric service" must be direct or indirect. While the stated goal is stable or certain retail electric service, the statute does not tell the commission how to reach it. This gives the commission discretion to determine how the "[t]erms, conditions, or charges" meet the criteria. *In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 68 ("Any lack of statutory guidance on that point should be read as a grant of discretion"); *Payphone Assn. v. Pub. Util. Comm.*, 109 Ohio St.3d 453, 2006-Ohio-2988, 849 N.E.2d 4, ¶ 25 ("When a statute does not prescribe a particular formula, the [commission] is vested with broad discretion").

{¶ 49} OCC has not shown an abuse of discretion. R.C. 4928.143(B)(2)(d) does not expressly exclude effects that are indirect; it does not use the word "direct," or even some equivalent. We would have to insert language into the statute to find in favor of OCC's preferred construction. But in construing a statute, we may not add or delete words. *State ex rel. Cincinnati Bell*

Tel. Co. v. Pub. Util. Comm., 105 Ohio St.3d 177, 2005-Ohio-1150, 824 N.E.2d 68, ¶ 32.

3. *Ohio Energy Group's Proposition of Law No. 1*: Whether R.C. 4928.143(B)(2)(d) allows the commission to order the recovery of wholesale charges through the RSR

{¶ 50} Ohio Energy Group argues that the commission cannot order the recovery of deferred wholesale capacity costs from retail customers under R.C. 4928.143(B)(2)(d). According to Ohio Energy, this provision specifically relates to retail electric service, so wholesale costs that are established outside the scope of an ESP and deferred for later recovery cannot be recovered under this provision. But Ohio Energy points to no language in R.C. 4928.143 that prohibits the commission from allowing the recovery of wholesale costs through retail rates. *See Util. Serv. Partners, Inc. v. Pub. Util. Comm.*, 124 Ohio St.3d 284, 2009-Ohio-6764, 921 N.E.2d 1038, ¶ 53 (rejecting argument when proponent failed to provide rationale justifying decision in its favor).

{¶ 51} Ohio Energy also claims that forcing retail customers to pay wholesale capacity costs that should be charged to CRES providers does not provide stability or certainty regarding retail electric service, as required by R.C. 4928.143(B)(2)(d). The underlying premise of this argument is factual, yet Ohio Energy fails to support its argument with any citations to the record. We reject the argument on that basis. *Allnet Communications Servs., Inc. v. Pub. Util. Comm.*, 70 Ohio St.3d 202, 206, 638 N.E.2d 516 (1994) (rejecting argument where appellant "provided no further reasoning or record citations to support" it).

Remaining challenges to the RSR

1. *OCC's Proposition of Law No. 1*: Whether the commission's order is unlawful and unreasonable because it requires retail consumers to pay twice for the cost of capacity

{¶ 52} OCC argues that the commission erred in counting capacity costs twice. According to OCC, the company's generation customers are already paying the company for capacity through its standard-service-offer rates. And these same customers will have to pay the RSR, which recovers deferred capacity costs plus interest. Likewise, OCC contends that shopping customers may also be required to pay twice for capacity. These arguments have effectively been resolved by our discussion of the transition-revenue issue.

2. Kroger's Proposition of Law No. 1: Whether the commission's order is unlawful because it mismatched cost allocation and cost recovery for the RSR, in violation of R.C. 4928.02

{¶ 53} Kroger raises one proposition of law, arguing that the commission erred when it approved the rate design of the RSR. Kroger claims that although the commission acted appropriately when it permitted AEP to allocate costs for the RSR to customer classes on a demand basis, the commission erred when it then allowed AEP to recover those costs through an energy charge. According to Kroger, the rate design of the RSR is unlawful and unreasonable because it discriminates against Kroger, and other high-demand customers whose energy usage is low relative to their demand due to greater efficiency, by forcing them to subsidize lower-demand, but less efficient, customers. *See* R.C. 4928.02(A) (state policy is to ensure nondiscriminatory and reasonably priced retail electric service). Kroger raises two arguments. We reject both.

a. Kroger has forfeited its primary argument on appeal

{¶ 54} Kroger's primary argument on appeal is that the commission failed to cite evidence to support its determination.

{¶ 55} Although not cited by Kroger, R.C. 4903.09 requires the commission to set forth the reasons for its decisions and prohibits summary rulings and conclusions that do not develop the supporting rationale or record. *MCI Telecommunications Corp. v. Pub. Util. Comm.*, 32 Ohio St.3d 306, 312, 513 N.E.2d 337 (1987); *Indus. Energy Users-Ohio v. Pub. Util. Comm.*, 117 Ohio St.3d 486, 2008-Ohio-990, 885 N.E.2d 195, ¶ 30. Kroger is correct that the commission's rehearing entry on this issue contains no citation to the record. Nevertheless, we lack jurisdiction to address Kroger's argument.

{¶ 56} The commission addressed the rate-design issue for the first time in the January 30, 2013 rehearing entry. But Kroger never filed a *second* application for rehearing that alleged error in the commission's January 30 rehearing entry. Therefore, we lack jurisdiction to consider the argument on appeal. *Discount Cellular, Inc. v. Pub. Util. Comm.*, 112 Ohio St.3d 360, 2007-Ohio-53, 859 N.E.2d 957, ¶ 66.

b. Kroger's rate-design argument otherwise lacks merit

{¶ 57} Kroger also argues that the rate design of the RSR violates the regulatory principle of cost causation, which requires that rates approved by the regulator reflect the costs actually caused by the customer who pays them. Kroger maintains that the commission misapplied this principle, resulting in a rate design that is inherently flawed and that requires one class of customers to subsidize the other.

{¶ 58} We have long given great deference to the commission on matters of rate design. *See Ohio Consumers' Counsel v. Pub. Util. Comm.*, 127 Ohio St.3d 524, 2010-Ohio-6239, 941 N.E.2d 757, ¶ 13. Our " 'function is not to weigh the evidence or to choose between alternative, fairly debatable rate structures. That would be to interfere with the jurisdiction and competence of the commission and to assume powers which this court is not suited to exercise.' " *Id.*

at ¶ 13, quoting *Cleveland Elec. Illum. Co. v. Pub. Util. Comm.*, 46 Ohio St.3d 105, 108, 346 N.E.2d 778 (1976).

{¶ 59} After review, we find that Kroger has failed to demonstrate any error, let alone reversible error. Kroger cites no authority that the commission is bound to apply the regulatory principle of cost causation whenever it is deciding an issue of rate design. Therefore, we can reject this argument on that ground. *See Ohio Consumers' Counsel v. Pub. Util. Comm.*, 125 Ohio St.3d 57, 2010-Ohio-134, 926 N.E.2d 261, ¶ 20.

II. Challenges against the ESP based on discriminatory pricing

{¶ 60} OCC argues that the commission approved capacity prices that discriminate against standard-service-offer ("SSO") customers (nonshoppers), in favor of marketers and shopping customers. We find that OCC has failed to demonstrate error.

{¶ 61} Ohio law does "not require uniformity in utility prices and rates." *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 109 Ohio St.3d 328, 2006-Ohio-2110, 847 N.E.2d 1184, ¶ 24. Rather, the statutes prohibit a utility from charging different rates only when performing " 'a like and contemporaneous service under substantially the same circumstances and conditions.' " *Id.* at ¶ 23, quoting R.C. 4905.33, and construing R.C. 4905.35 as having "the same effect," *id.* OCC, however, provides no evidence that SSO customers are situated similarly to CRES providers when it comes to the provision of capacity service.

{¶ 62} Likewise, OCC offers no evidence or explanation of any similarity between SSO customers and shopping customers when it comes to capacity service. AEP provides capacity to SSO customers as part of its bundled generation service, but it does not provide capacity directly to shopping customers. Instead, AEP sells generation capacity wholesale to CRES providers, who in turn sell generation service directly to shopping customers, with each

CRES provider deciding how much of the wholesale capacity cost to pass on to retail consumers. First Rehearing Entry at 33.

{¶ 63} In sum, OCC has not carried its burden, and therefore we reject the arguments on that ground. *See generally In re Application of Duke Energy Ohio, Inc.*, 131 Ohio St.3d 487, 2012-Ohio-1509, 967 N.E.2d 201, ¶ 17-18 (appellant bears the burden on appeal of showing that the order is unlawful or unreasonable).

AEP's Cross-Appeal

I. *AEP's Proposition of Law No. V1*: Whether the commission erred in determining the threshold for the "significantly excessive earnings" test

{¶ 64} AEP first argues on cross-appeal that the commission erred when it imposed a significantly-excessive-earnings test ("SEET") threshold for the term of the ESP that was arbitrary and unsupported by the record. Electric-distribution utilities that opt to provide service under an electric-security plan must undergo an annual earnings review. R.C. 4928.143(F) requires the commission annually to consider whether the plan resulted in "significantly excessive earnings" compared to companies facing "comparable" risk. If the ESP resulted in significantly excessive earnings, the utility must return the excess to its customers. *Id.* In the order below, the commission set the SEET threshold at 12 percent, meaning that only a return on investment of more than 12 percent would be considered significantly excessive. ESP Order at 37; First Rehearing Entry at 41-42.

{¶ 65} Whether a plan resulted in excessive earnings must be measured by

> whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and

> financial risk, with such adjustments for capital structure as may be appropriate.

R.C. 4928.143(F). AEP argues that in setting the SEET threshold, the commission did not compare AEP's return on common equity with the returns of comparable publicly traded companies that were earned *during the same period.* Moreover, the company asserts that the commission never explained why it failed to conduct the statutorily required comparison.

{¶ 66} AEP is correct that the commission failed to explain its decision. AEP complained on rehearing that the threshold was not based on "estimates of the 'return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk' to AEP Ohio, as the SEET statute requires." The company also complained about the commission's lack of explanation for departing from the statutory process. The commission never offered a response to AEP's claims and thus failed to explain its decision. This was error. *See In re Fuel Adjustment Clauses for Columbus S. Power Co. & Ohio Power Co.*, 140 Ohio St.3d 352, 2014-Ohio-3764, 18 N.E.3d 1157, ¶ 45. Therefore, we reverse this part of the order and remand so that the commission can address this issue in the first instance.

II. AEP's Proposition of Law No. V1I: Whether the commission's order impaired the company's right to withdraw the ESP under R.C. 4928.143(C)(2)(a)

{¶ 67} AEP's second argument on cross-appeal is that the commission's order deprived the company of its right under R.C. 4928.143(C)(2)(a) to withdraw the ESP. R.C. 4928.143(C)(1) requires the commission to do one of three things when considering an ESP application: (1) "approve," (2) "modify and approve," or (3) "disapprove" the application. Under R.C. 4928.143(C)(2)(a), if the commission issues an order that "modifies and approves an application," the

utility "may withdraw the application, thereby terminating it, and may file a new standard service offer." AEP asserts that it cannot meaningfully exercise its statutory right to withdraw the modified ESP because the order directed the company to accelerate the use of energy auctions, but failed to address auction-design and related issues, deferring those issues for resolution in another proceeding. This argument lacks merit.

{¶ 68} Nothing prevented AEP from withdrawing the ESP once the commission issued its order modifying the timing of the auctions and informed the company of its plan to decide auction-design issues in another case. AEP complains that it cannot exercise its right to withdraw when it does not know and cannot even anticipate the actual economic effect of the specific design of the auctions until later. But AEP overlooks the fact that it was the one who had proposed that the commission decide the details of the competitive-auction process in a separate proceeding. The company cannot take advantage of an error that it itself invited or induced the commission to make. *State ex rel. Johnson v. Ohio Adult Parole Auth.*, 95 Ohio St.3d 463, 2002-Ohio-2481, 768 N.E.2d 1176, ¶ 6; *Fostoria v. Ohio Patrolmen's Benevolent Assn.*, 106 Ohio St.3d 194, 2005-Ohio-4558, 833 N.E.2d 720, ¶ 12.

III. AEP's Proposition of Law No. VIII: Whether the commission erred when it extended the state compensation mechanism to standard-service-offer auctions[4]

{¶ 69} In its final argument on cross-appeal, AEP contends that the commission erred when it extended the state compensation mechanism to SSO auctions and SSO customers. But this argument was not set forth in AEP's notice of cross-appeal and is therefore forfeited. R.C. 4903.13 (the procedure for seeking reversal of a commission order is through a notice of appeal "setting forth the

[4] At page 47 of its second merit brief, AEP misidentifies its final proposition of law as "No. IV," instead of No. VIII.

order appealed from and the errors complained of"); *Cincinnati Gas & Elec. Co. v. Pub. Util. Comm.*, 103 Ohio St.3d 398, 2004-Ohio-5466, 816 N.E.2d 238, ¶ 21; *In re Complaint of Smith v. Ohio Edison Co.*, 137 Ohio St.3d 7, 2013-Ohio-4070, 996 N.E.2d 927, ¶ 28.

CONCLUSION

{¶ 70} For the foregoing reasons, we reverse the commission's orders in part, affirm them in part, and remand the cause to the commission for further review.

Orders affirmed in part
and reversed in part,
and cause remanded.

O'DONNELL and FRENCH, JJ., concur.

O'CONNOR, C.J., concurs in part and dissents in part with an opinion that LANZINGER, J., joins.

PFEIFER, J., concurs in part and dissents in part with an opinion that O'NEILL, J., joins.

O'CONNOR, C.J., concurring in part and dissenting in part.

{¶ 71} I believe that the majority prematurely reaches its conclusions that the commission's order violates R.C. 4928.38 and that AEP is recovering the equivalent of unlawful transition revenue through the Retail Stability Rider ("RSR"). I thus dissent in part.

ANALYSIS

{¶ 72} R.C. Chapter 4928 is a labyrinthian scheme that governs Ohio's retail electric service, i.e., "any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption." R.C. 4928.01(27). Among its provisions are those permitting and forbidding the recovery of transition costs.

FirstEnergy Corp. v. Pub. Util. Comm., 95 Ohio St.3d 401, 2002-Ohio-2430, 768 N.E.2d 648, ¶ 14; R.C. 4928.37; R.C. 4928.39; R.C. 4928.141(A).

{¶ 73} In the proceedings below, the commission found that R.C. 4928.143(B)(2)(d) permitted American Electric Power ("AEP") to include the RSR as part of its electric security plan ("ESP"). Pub. Util. Comm. Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM, 31-32 (Aug. 8, 2012) (the "ESP Order"). The practical effect of that decision was that AEP collected over $500,000,000 in additional revenue through the RSR, which AEP had designed, in part, to recover lost revenue from competitive retail-electric-service providers.

{¶ 74} Appellant the Office of the Ohio Consumers' Counsel contends that the commission acted improperly in allowing AEP to collect the revenue because the statutory period set by the General Assembly for the recovery of transition costs had ended. *See* R.C. 4928.37(A)(1), 4928.38, and 4928.40(A). The majority agrees and reverses the approval of the RSR on the basis that AEP is recovering the equivalent of unlawful transition revenue through the rider in violation of R.C. 4928.38. But in doing so, the majority ignores what could be significant language in the ESP statute, R.C. 4928.143(B), by relegating that language to a footnote and then ignoring it. Majority Opinion at fn. 3.

{¶ 75} R.C. 4928.143(B) contains broadly worded language that states "[n]otwithstanding any other provision" in R.C. Title 49 "to the contrary," except the provisions in "division (D) of this section, divisions (I), (J), and (K) of section 4928.20, division (E) of section 4928.64, and section 4928.69 of the Revised Code," an electric security plan may provide or include, without limitation, a host of costs the utility incurs in providing electric service.[5]

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[5] R.C. 4928.143(B) provides:

Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary except division (D) of this section, divisions (I), (J), and (K) of section 4928.20, division (E) of section 4928.64, and section 4928.69 of the Revised Code:

(1) An electric security plan shall include provisions relating to the supply and pricing of electric generation service. * * *

(2) The plan may provide for or include, without limitation, any of the following:

(a) Automatic recovery of any of the following costs of the electric distribution utility, provided the cost is prudently incurred: the cost of fuel used to generate the electricity supplied under the offer; the cost of purchased power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes;

(b) A reasonable allowance for construction work in progress for any of the electric distribution utility's cost of constructing an electric generating facility or for an environmental expenditure for any electric generating facility of the electric distribution utility, provided the cost is incurred or the expenditure occurs on or after January 1, 2009. Any such allowance shall be subject to the construction work in progress allowance limitations of division (A) of section 4909.15 of the Revised Code, except that the commission may authorize such an allowance upon the incurrence of the cost or occurrence of the expenditure. No such allowance for generating facility construction shall be authorized, however, unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Further, no such allowance shall be authorized unless the facility's construction was sourced through a competitive bid process, regarding which process the commission may adopt rules. An allowance approved under division (B)(2)(b) of this section shall be established as a nonbypassable surcharge for the life of the facility.

(c) The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate

associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements.

(d) Terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service;

(e) Automatic increases or decreases in any component of the standard service offer price;

(f) Consistent with sections 4928.23 to 4928.2318 of the Revised Code, both of the following:

(i) Provisions for the electric distribution utility to securitize any phase-in, inclusive of carrying charges, of the utility's standard service offer price, which phase-in is authorized in accordance with section 4928.144 of the Revised Code;

(ii) Provisions for the recovery of the utility's cost of securitization.

(g) Provisions relating to transmission, ancillary, congestion, or any related service required for the standard service offer, including provisions for the recovery of any cost of such service that the electric distribution utility incurs on or after that date pursuant to the standard service offer;

(h) Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking, a revenue decoupling mechanism or any other incentive ratemaking, and provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

(i) Provisions under which the electric distribution utility may implement economic development, job retention, and energy efficiency programs, which provisions may allocate program costs across all

{¶ 76} The provision could be construed to allow an ESP to include charges that other provisions of R.C. Title 49 prohibit. Here, even assuming that the majority is correct that R.C. 4928.38 bars the recovery of transition revenue, R.C. 4928.143(B) nevertheless could be read to create an exception to the prohibition on transition revenue as long as the revenues are recoverable under the requirements of R.C. 4928.143(B)(2). Stated differently, the word "notwithstanding" could render R.C. 4928.38 inapplicable if the revenues are recoverable under one of the many provisions of R.C. 4928.143(B)(2).

{¶ 77} I recognize that the commission did not rely on the "notwithstanding" provision of R.C. 4928.143(B) in the proceedings below. And although it appears that no party has squarely raised the issue to this court, two parties, FirstEnergy Solutions and IEU, cited the "notwithstanding" provision of R.C. 4928.143(B) before the commission in relation to another rider (the Generation Resource Rider). ESP Order at 21. In that context, the parties' interpretation of the provision suggests that the "notwithstanding" clause could be read broadly as an exception. The commission, however, decided the question on other grounds and never addressed the "notwithstanding" argument, *see* ESP Order at 19-25, and I am unaware of any case in which the commission has considered or clarified the particular language of R.C. 4928.143(B).

{¶ 78} We could decide the meaning of the provision in the first instance. But we can, and should, consider the expertise of a state agency in interpreting a law where, as here, there are "highly specialized issues" involved and where "agency expertise" would be "of assistance in discerning the presumed intent of

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> classes of customers of the utility and those of electric distribution utilities in the same holding company system.

(Emphasis added.)

our General Assembly." *Consumers' Counsel v. Pub. Util. Comm.*, 58 Ohio St.2d 108, 110, 388 N.E.2d 1370 (1979).

{¶ 79} Given that the "notwithstanding" provision could create an exception to the prohibition against the recovery of transition revenue and that the commission has offered no guidance on the meaning of that provision, I would remand the cause to the commission to consider and interpret the statutory language before rendering a decision on whether AEP is improperly recovering transition costs. *See, e.g., In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 31-35. By doing so, we would not only respect the role of the General Assembly to create the framework by which utilities must provide service to the millions of Ohio consumers who rely on safe, affordable electrical service, but also the collective expertise of the commission in a complex area of law that implicates important public-health and financial-policy considerations.

LANZINGER, J., concurs in the foregoing opinion.

PFEIFER, J., concurring in part and dissenting in part.

{¶ 80} I concur in the portion of the majority opinion that concludes that the Public Utilities Commission ("PUCO") erred when it allowed Ohio Power to collect the equivalent of transition revenues.

{¶ 81} But I dissent from the portion of the majority opinion that allows the recapture of a discount offered to marketers from retail customers. Pursuant to the PUCO order before us, Ohio Power is allowed to sell capacity to marketers at a rate that is less than its retail customers pay. That does not, by itself, offend any sense of justice or fair play. But requiring the retail customers, who already pay full cost, to make up the difference between the rate Ohio Power charges the marketers and the rate it charges the public does. We are not talking about a small number. The discount that Ohio Power has offered to marketers, some of

whom might be its own subsidiaries, amounts over a period of years to close to $650 million. No statutory authority enabled the PUCO to allow Ohio Power to recoup from its retail customers the discount it grants to marketers. The PUCO justifies the recapture of the discount by saying that it promotes stable electric service prices. Perhaps that is true, but it also results in artificially high retail utility costs.

{¶ 82} The PUCO has determined that Ohio Power's cost of providing capacity is $188.88 per megawatt day. *In re Comm. Rev. of Capacity Charges of Ohio Power Co.,* Pub. Util. Comm. No. 10-2929-EL-UNC, at 33 (July 2, 2012). In its brief, the Office of the Ohio Consumers' Counsel stated that the current standard-service-offer rate charged to retail customers includes a capacity charge of approximately $355.72 per megawatt-day. If true, this outrageous overcharge to Ohio Power's own nonshopping retail customers is unwarranted and outside the purview of the rate-setting mechanism. R.C. 4928.144, which ostensibly justifies the PUCO's action, allows rates to be phased in, it does not allow the recapture of a discount offered to marketers from retail customers. In essence, the PUCO is requiring retail customers, who in the main do not shop for service, to subsidize customers who do shop. The authority to do this is not found in 2008 Am.Sub.S.B. No. 221 or anywhere else in the Revised Code.

{¶ 83} In the past, Ohio Power's capacity charges have been based on rates established by auctions held by PJM Interconnection, L.L.C. *See* Pub. Util. Comm. No. 10-2929-EL-UNC at 14. I would send this case back to the PUCO with instructions for it to determine the appropriate market price for capacity generation and to limit the rates it allows Ohio Power to charge to that market price.

{¶ 84} The outcome of this case appears to provide another extra-legal gift from the PUCO to the management and shareholders of AEP, the owner of Ohio Power, this time of roughly $500 million from the retail stability charge. For

other examples, *see In re Application of Ohio Power Co.*, 144 Ohio St.3d 1, 2015-Ohio-2056, 40 N.E.3d 1060, ¶ 48 (Pfeifer, J., dissenting) (Ohio Power received an unwarranted $130 million); *In re Application of Columbus S. Power Co.*, 138 Ohio St.3d 448, 2014-Ohio-462, 8 N.E.3d 863, ¶ 56 (Pfeifer, J., dissenting) (AEP allowed to retain $368 million of charges that were unjustified).

{¶ 85} Based on the foregoing, I concur in part and dissent in part.

O'NEILL, J., concurs in the foregoing opinion.

Bruce J. Weston, Consumers' Counsel, and Maureen R. Grady, Terry L. Etter, and Joseph P. Serio, Assistant Consumers' Counsel, for appellant and cross-appellee Ohio Consumers' Counsel.

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Matthew J. Satterwhite and Steven T. Nourse; Porter, Wright, Morris & Arthur, L.L.P., Kathleen M. Trafford, James B. Hadden, Daniel R. Conway, and L. Bradfield Hughes; and MoloLamken, L.L.P., Jeffrey A. Lamken, and Martin V. Totaro, for appellee and cross-appellant, Ohio Power Company.

ATTACHMENT B

Syllabus

NOTE: Where it is feasible, a syllabus (headnote) will be released, as is being done in connection with this case, at the time the opinion is issued. The syllabus constitutes no part of the opinion of the Court but has been prepared by the Reporter of Decisions for the convenience of the reader. See *United States* v. *Detroit Timber & Lumber Co.*, 200 U. S. 321, 337.

SUPREME COURT OF THE UNITED STATES

Syllabus

HUGHES, CHAIRMAN, MARYLAND PUBLIC SERVICE COMMISION, ET AL. *v.* TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL.

CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE FOURTH CIRCUIT

No. 14–614. Argued February 24, 2016—Decided April 19, 2016*

The Federal Power Act (FPA) vests in the Federal Energy Regulatory Commission (FERC) exclusive jurisdiction over wholesale sales of electricity in the interstate market, but "leaves to the States alone, the regulation of [retail electricity sales]." *FERC* v. *Electric Power Supply Assn.*, 577 U. S. ___, ___. In Maryland and other States that have deregulated their energy markets, "load serving entities" (LSEs) purchase electricity at wholesale from independent power generators for delivery to retail consumers. Interstate wholesale transactions in deregulated markets typically occur through (1) bilateral contracting, where LSEs agree to purchase a certain amount of electricity from generators at a certain rate over a certain period of time; and (2) competitive wholesale auctions administered by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), nonprofit entities that manage certain segments of the electricity grid.

PJM Interconnection (PJM), an RTO overseeing a multistate grid, operates a capacity auction. The capacity auction is designed to identify need for new generation and to accommodate long-term bilateral contracts for capacity. PJM predicts demand three years into the future and assigns a share of that demand to each participating LSE. Owners of capacity to produce electricity in three years' time then bid

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*Together with No. 14–623, *CPV Maryland, LLC* v. *Talen Energy Marketing, LLC, fka PPL EnergyPlus, LLC, et al.*, also on certiorari to the same court

that capacity into the auction for sale to PJM at rates the sellers set in their bids. PJM accepts bids until it has purchased enough capacity to satisfy anticipated demand. All accepted capacity sellers receive the highest accepted rate, called the "clearing price." LSEs then must purchase, from PJM, enough electricity to satisfy their assigned share of overall projected demand. FERC extensively regulates the structure of the capacity auction to ensure that it efficiently balances supply and demand, producing a just and reasonable clearing price.

Concerned that the PJM capacity auction was failing to encourage development of sufficient new in-state generation, Maryland enacted its own regulatory program. Maryland selected, through a proposal process, petitioner CPV Maryland, LLC (CPV), to construct a new power plant and required LSEs to enter into a 20-year pricing contract (called a contract for differences) with CPV at a rate CPV specified in its proposal. Under the terms of the contract, CPV sells its capacity to PJM through the auction, but—through mandated payments from or to LSEs—receives the contract price rather than the clearing price for these sales to PJM. In a suit filed by incumbent generators (respondents here) against members of the Maryland Public Service Commission—CPV intervened as a defendant—the District Court issued a declaratory judgment holding that Maryland's program improperly sets the rate CPV receives for interstate wholesale capacity sales to PJM. The Fourth Circuit affirmed.

Held: Maryland's program is preempted because it disregards the interstate wholesale rate FERC requires. A state law is preempted where "Congress has legislated comprehensively to occupy an entire field of regulation," *Northwest Central Pipeline Corp.* v. *State Corporation Comm'n of Kan.*, 489 U. S. 493, 509, as well as "'where, under the circumstances of [a] particular case, [the challenged state law] stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress,'" *Crosby* v. *National Foreign Trade Council*, 530 U. S. 363, 373. Exercising its exclusive authority over interstate wholesale sales, see 16 U. S. C. §824(b)(1), FERC has approved PJM's capacity auction as the sole ratesetting mechanism for capacity sales to PJM, and has deemed the clearing price *per se* just and reasonable. However, Maryland—through the contract for differences—guarantees CPV a rate distinct from the clearing price for its interstate capacity sales to PJM. By adjusting an interstate wholesale rate, Maryland's program contravenes the FPA's division of authority between state and federal regulators.

That Maryland was attempting to encourage construction of new in-state generation does not save its program. States may regulate within their assigned domain even when their laws incidentally affect areas within FERC's domain. But they may not seek to achieve

ends, however legitimate, through regulatory means that intrude on FERC's authority over interstate wholesale rates, as Maryland has done here. See *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U. S. 354, 373; *Nantahala Power & Light Co.* v. *Thornburg*, 476 U. S. 953, 966. Maryland and CPV analogize the contract for differences to traditional bilateral contracts for capacity. Unlike traditional bilateral contracts, however, the contract for differences does not transfer ownership of capacity from one party to another outside the auction. Instead, Maryland's program operates within the auction, mandating LSEs and CPV to exchange money based on the cost of CPV's capacity sales to PJM.

Maryland's program is rejected only because it disregards an interstate wholesale rate required by FERC. Neither Maryland nor other States are foreclosed from encouraging production of new or clean generation through measures that do not condition payment of funds on capacity clearing the auction. Pp. 11–15.

753 F. 3d 467, affirmed.

GINSBURG, J., delivered the opinion of the Court, in which ROBERTS, C. J., and KENNEDY, BREYER, ALITO, SOTOMAYOR, and KAGAN, JJ., joined. SOTOMAYOR, J., filed a concurring opinion. THOMAS, J., filed an opinion concurring in part and concurring in the judgment.

NOTICE: This opinion is subject to formal revision before publication in the preliminary print of the United States Reports. Readers are requested to notify the Reporter of Decisions, Supreme Court of the United States, Washington, D. C. 20543, of any typographical or other formal errors, in order that corrections may be made before the preliminary print goes to press.

SUPREME COURT OF THE UNITED STATES

Nos. 14–614 and 14–623

W. KEVIN HUGHES, CHAIRMAN, MARYLAND PUBLIC SERVICE COMMISSION, ET AL., PETITIONERS
14–614 *v.*
TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL.

CPV MARYLAND, LLC, PETITIONER
14–623 *v.*
TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE FOURTH CIRCUIT

[April 19, 2016]

JUSTICE GINSBURG delivered the opinion of the Court.

The Federal Power Act (FPA), 41 Stat. 1063, as amended, 16 U. S. C. §791a *et seq.*, vests in the Federal Energy Regulatory Commission (FERC) exclusive jurisdiction over wholesale sales of electricity in the interstate market. FERC's regulatory scheme includes an auction-based market mechanism to ensure wholesale rates that are just and reasonable. FERC's scheme, in Maryland's view, provided insufficient incentive for new electricity generation in the State. Maryland therefore enacted its own regulatory program. Maryland's program provides subsidies, through state-mandated contracts, to a new generator, but conditions receipt of those subsidies on the new

generator selling capacity into a FERC-regulated wholesale auction. In a suit initiated by competitors of Maryland's new electricity generator, the Court of Appeals for the Fourth Circuit held that Maryland's scheme impermissibly intrudes upon the wholesale electricity market, a domain Congress reserved to FERC alone. We affirm the Fourth Circuit's judgment.

I

A

Under the FPA, FERC has exclusive authority to regulate "the sale of electric energy at wholesale in interstate commerce." §824(b)(1). A wholesale sale is defined as a "sale of electric energy to any person for resale." §824(d). The FPA assigns to FERC responsibility for ensuring that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission . . . shall be just and reasonable." §824d(a). See also §824e(a) (if a rate or charge is found to be unjust or unreasonable, "the Commission shall determine the just and reasonable rate"). "But the law places beyond FERC's power, and leaves to the States alone, the regulation of 'any other sale'—most notably, any retail sale—of electricity." *FERC* v. *Electric Power Supply Assn.*, 577 U. S. ___, ___ (2016) (*EPSA*) (slip op., at 1) (quoting §824(b)). The States' reserved authority includes control over in-state "facilities used for the generation of electric energy." §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.").

"Since the FPA's passage, electricity has increasingly become a competitive interstate business, and FERC's role

has evolved accordingly." *EPSA*, 577 U. S., at ___ (slip op., at 4). Until relatively recently, most state energy markets were vertically integrated monopolies—*i.e.*, one entity, often a state utility, controlled electricity generation, transmission, and sale to retail consumers. Over the past few decades, many States, including Maryland, have deregulated their energy markets. In deregulated markets, the organizations that deliver electricity to retail consumers—often called "load serving entities" (LSEs)—purchase that electricity at wholesale from independent power generators. To ensure reliable transmission of electricity from independent generators to LSEs, FERC has charged nonprofit entities, called Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), with managing certain segments of the electricity grid.

Interstate wholesale transactions in deregulated markets typically occur through two mechanisms. The first is bilateral contracting: LSEs sign agreements with generators to purchase a certain amount of electricity at a certain rate over a certain period of time. After the parties have agreed to contract terms, FERC may review the rate for reasonableness. See *Morgan Stanley Capital Group Inc.* v. *Public Util. Dist. No. 1 of Snohomish Cty.*, 554 U. S. 527, 546–548 (2008) (Because rates set through good-faith arm's-length negotiation are presumed reasonable, "FERC may abrogate a valid contract only if it harms the public interest."). Second, RTOs and ISOs administer a number of competitive wholesale auctions: for example, a "same-day auction" for immediate delivery of electricity to LSEs facing a sudden spike in demand; a "next-day auction" to satisfy LSEs' anticipated near-term demand; and a "capacity auction" to ensure the availability of an adequate supply of power at some point far in the future.

These cases involve the capacity auction administered by PJM Interconnection (PJM), an RTO that oversees the

electricity grid in all or parts of 13 mid-Atlantic and Midwestern States and the District of Columbia. The PJM capacity auction functions as follows. PJM predicts electricity demand three years ahead of time, and assigns a share of that demand to each participating LSE. Owners of capacity to produce electricity in three years' time bid to sell that capacity to PJM at proposed rates. PJM accepts bids, beginning with the lowest proposed rate, until it has purchased enough capacity to satisfy projected demand. No matter what rate they listed in their original bids, all accepted capacity sellers receive the highest accepted rate, which is called the "clearing price."[1] LSEs then must purchase from PJM, at the clearing price, enough electricity to satisfy their PJM-assigned share of overall projected demand. The capacity auction serves to identify need for new generation: A high clearing price in the capacity auction encourages new generators to enter the market, increasing supply and thereby lowering the clearing price in same-day and next-day auctions three years' hence; a low clearing price discourages new entry and encourages retirement of existing high-cost generators.[2]

The auction is designed to accommodate long-term bilateral contracts for capacity. If an LSE has acquired a

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[1] For example, if four power plants bid to sell capacity at, respectively, $10/unit, $20/unit, $30/unit, and $40/unit, and the first three plants provide enough capacity to satisfy projected demand, PJM will purchase capacity only from those three plants, each of which will receive $30/unit, the clearing price.

[2] Because PJM operates the electricity grid in a very large region of the country, PJM divides its overall grid into geographic subregions and makes adjustments to the clearing price to reflect operating conditions in those subregions. For instance, PJM may pay a higher rate in or near areas where transmission-line congestion limits the amount of electricity that can be imported from other areas. The elevated clearing price might encourage a company to site a new power plant in a subregion where the need for local generation is great rather than elsewhere in PJM's grid.

certain amount of capacity through a long-term bilateral contract with a generator, the LSE—not the generator—is considered the owner of that capacity for purposes of the auction. The LSE sells that capacity into the auction, where it counts toward the LSE's assigned share of PJM-projected demand, thereby reducing the net costs of the LSE's required capacity purchases from PJM.[3] LSEs generally bid their capacity into the auction at a price of $0, thus guaranteeing that the capacity will clear at any price. Such bidders are called "price takers." Because the fixed costs of building generating facilities often vastly exceed the variable costs of producing electricity, many generators also function as price takers.

FERC extensively regulates the structure of the PJM capacity auction to ensure that it efficiently balances supply and demand, producing a just and reasonable clearing price. See *EPSA*, 577 U. S., at ___ (slip op., at 5) (the clearing price is "the price an efficient market would produce"). Two FERC rules are particularly relevant to

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[3]To take a simplified example, assume an LSE has signed a long-term bilateral contract with a generator to purchase 50 units of electricity annually at a price of $40/unit (total annual cost: $2,000). In a given year when the auction clearing price is $50/unit, assume PJM requires the LSE to purchase 100 units of electricity to satisfy its share of projected demand. The LSE bids the 50 units of capacity it already owns into the PJM auction, and PJM pays the LSE $2,500 for those 50 units. Although the LSE then must pay PJM $5,000 for the 100 units it must purchase to satisfy projected demand, the net cost to the LSE of auction participation is only $2,500. Note that the effective price the LSE pays for 50 of the 100 units it must purchase from PJM—the amount purchased through the long-term contract—is the contract price, not the clearing price. That is, the LSE pays the utility $2,000 for 50 units of capacity, receives $2,500 from PJM after selling that capacity into the auction, and then pays $2,500 to PJM to purchase 50 units of capacity, resulting in a net cost of $2,000—the contract price—for those 50 units. The LSE, of course, must pay the full clearing price—$50/unit—for the other 50 units it is obliged to purchase to satisfy its full share of projected demand.

these cases. First, the Minimum Offer Price Rule (MOPR) requires new generators to bid capacity into the auction at or above a price specified by PJM, unless those generators can prove that their actual costs fall below the MOPR price. Once a new generator clears the auction at the MOPR price, PJM deems that generator an efficient entrant and exempts it from the MOPR going forward, allowing it to bid its capacity into the auction at any price it elects, including $0. Second, the New Entry Price Adjustment (NEPA) guarantees new generators, under certain circumstances, a stable capacity price for their first three years in the market. The NEPA's guarantee eliminates, for three years, the risk that the new generator's entry into the auction might so decrease the clearing price as to prevent that generator from recovering its costs.

B

Around 2009, Maryland electricity regulators became concerned that the PJM capacity auction was failing to encourage development of sufficient new in-state generation. Because Maryland sits in a particularly congested part of the PJM grid, importing electricity from other parts of the grid into the State is often difficult. To address this perceived supply shortfall, Maryland regulators proposed that FERC extend the duration of the NEPA from three years to ten. FERC rejected the proposal. *PJM*, 126 FERC ¶62,563 (2009). "[G]iving new suppliers longer payments and assurances unavailable to existing suppliers," FERC reasoned, would improperly favor new generation over existing generation, throwing the auction's market-based price-setting mechanism out of balance. *Ibid.* See also *PJM*, 128 FERC ¶61,789 (2009) (order on petition for rehearing) ("Both new entry and retention of existing efficient capacity are necessary to ensure reliability and both should receive the same price so that the price signals are not skewed in favor of new

entry.").

Shortly after FERC rejected Maryland's NEPA proposal, the Maryland Public Service Commission promulgated the Generation Order at issue here. Under the order, Maryland solicited proposals from various companies for construction of a new gas-fired power plant at a particular location, and accepted the proposal of petitioner CPV Maryland, LLC (CPV). Maryland then required LSEs to enter into a 20-year pricing contract (the parties refer to this contract as a "contract for differences") with CPV at a rate CPV specified in its accepted proposal.[4] Unlike a traditional bilateral contract for capacity, the contract for differences does not transfer ownership of capacity from CPV to the LSEs. Instead, CPV sells its capacity on the PJM market, but Maryland's program guarantees CPV the contract price rather than the auction clearing price.

If CPV's capacity clears the PJM capacity auction and the clearing price falls below the price guaranteed in the contract for differences, Maryland LSEs pay CPV the difference between the contract price and the clearing price. The LSEs then pass the costs of these required payments along to Maryland consumers in the form of higher retail prices. If CPV's capacity clears the auction and the clearing price exceeds the price guaranteed in the contract for differences, CPV pays the LSEs the difference between the contract price and the clearing price, and the LSEs then pass the savings along to consumers in the form of lower retail prices. Because CPV sells its capacity exclusively in the PJM auction market, CPV receives no payment from Maryland LSEs or PJM if its capacity fails to clear the auction. But CPV is guaranteed a certain rate if its capacity does clear, so the contract's terms encourage

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[4]New Jersey implemented a similar program around the same time. The duration of the price guarantee for the New Jersey program is 15 years rather than Maryland's 20.

CPV to bid its capacity into the auction at the lowest possible price.[5]

Prior to enactment of the Maryland program, PJM had exempted new state-supported generation from the MOPR, allowing such generation to bid capacity into the

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[5]Two simplified examples illustrate how Maryland's program interacts with the PJM capacity auction. First, consider a hypothetical situation where the clearing price falls below the price guaranteed in the contract for differences. Assume that CPV's plant produces 10,000 units of electricity a year, and that the 20-year price guaranteed under the contract is $30/unit. Assume further that, in a given year during the duration of the price guarantee, the clearing price is $20/unit, and CPV's capacity clears the auction. CPV receives payments from Maryland LSEs of $10/unit, or $100,000, and payments from PJM of $20/unit, or $200,000. The rate CPV receives from the capacity auction is therefore $30/unit—the contract price—not $20/unit—the clearing price. Under PJM auction rules, Maryland LSEs then must purchase from PJM, at the clearing price of $20/unit, enough capacity to satisfy their assigned shares of anticipated demand. Assume that PJM requires Maryland LSEs to purchase 40,000 units of capacity. Total capacity-auction expenses for Maryland LSEs would therefore include both the payment to CPV ($100,000) and the full cost of purchasing capacity from PJM ($800,000), or $900,000. Absent Maryland's program, the LSEs' capacity-auction expenses would have included only the total cost of capacity purchases from PJM, or $800,000.

Now assume instead that the clearing price in a given year is $40/unit, which exceeds the $30/unit contract price, and that CPV's capacity clears the auction. CPV receives payments from PJM of $40/unit, or $400,000. CPV then must pay Maryland LSEs the difference between the contract price and the clearing price—in this case, $10/unit, or $100,000. The rate CPV receives from the capacity auction is therefore the contract price—$30/unit—the same price CPV received in the above example. Maryland LSEs then must purchase from PJM, at the clearing price of $40/unit, enough capacity to satisfy their share of anticipated demand. Assume that PJM again requires Maryland LSEs to purchase 40,000 units of capacity. Total capacity-auction expenses for Maryland LSEs would therefore include the full cost of capacity purchases from PJM ($1,600,000), minus the payment from CPV ($100,000), or $1,500,000. Absent Maryland's program, the LSEs would have had to pay $1,600,000 to PJM without receiving any offsetting payments from CPV.

auction at $0 without first clearing at the MOPR price. Responding to a complaint filed by incumbent generators in the Maryland region who objected to Maryland's program (and the similar New Jersey program), FERC eliminated this exemption. *PJM*, 135 FERC ¶61,106 (2011). See also 137 FERC ¶61,145 (2011) (order on petition for rehearing) ("Our intent is not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources, or unreasonably interfere with those objectives. We are forced to act, however, when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's [capacity auction] is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity."); *New Jersey Bd. of Pub. Util.* v. *FERC*, 744 F. 3d 74, 79–80 (CA3 2014) (upholding FERC's elimination of the state-supported generation exemption). In the first year CPV bid capacity from its new plant into the PJM capacity auction, that capacity cleared the auction at the MOPR rate, so CPV was thereafter eligible to function as a price taker.

In addition to seeking the elimination of the state-supported generation exemption, incumbent generators—respondents here—brought suit in the District of Maryland against members of the Maryland Public Service Commission in their official capacities. The incumbent generators sought a declaratory judgment that Maryland's program violates the Supremacy Clause by setting a wholesale rate for electricity and by interfering with FERC's capacity-auction policies.[6] CPV intervened as a

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[6] Because neither CPV nor Maryland has challenged whether plaintiffs may seek declaratory relief under the Supremacy Clause, the Court assumes without deciding that they may. See Brief for Public Utility Law Project of New York, Inc., as *Amicus Curiae* 21 (arguing that the incumbent generators should have been required to exhaust administrative remedies before filing suit).

defendant. After a six-day bench trial, the District Court issued a declaratory judgment holding that Maryland's program improperly sets the rate CPV receives for interstate wholesale capacity sales to PJM. *PPL Energyplus, LLC* v. *Nazarian*, 974 F. Supp. 2d 790, 840 (Md. 2013). "While Maryland may retain traditional state authority to regulate the development, location, and type of power plants within its borders," the District Court explained, "the scope of Maryland's power is necessarily limited by FERC's exclusive authority to set wholesale energy and capacity prices." *Id.*, at 829.[7]

The Fourth Circuit affirmed. Relying on this Court's decision in *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U. S. 354, 370 (1988), the Fourth Circuit observed that state laws are preempted when they "den[y] full effect to the rates set by FERC, even though [they do] not seek to tamper with the actual terms of an interstate transaction." *PPL EnergyPlus, LLC* v. *Nazarian*, 753 F. 3d 467, 476 (2014). Maryland's program, the Fourth Circuit reasoned, "functionally sets the rate that CPV receives for its sales in the PJM auction," "a FERC-approved market mechanism." *Id.*, at 476–477. "[B]y adopting terms and prices set by Maryland, not those sanctioned by FERC," the Fourth Circuit concluded, Maryland's program "strikes at the heart of the agency's statutory power." *Id.*, at 478.[8] The Fourth Circuit cautioned that it "need not express an opinion on other state efforts to encourage new generation, such as direct subsidies or

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[7] Respondents also raised arguments under the Dormant Commerce Clause and 42 U. S. C. §1983. The District Court rejected those arguments, *PPL Energyplus, LLC* v. *Nazarian*, 974 F. Supp. 2d 790, 841–855 (Md. 2013), the Fourth Circuit did not address them, and they are irrelevant at this stage.

[8] For the same reason, the Third Circuit found New Jersey's similar program preempted. *PPL Energyplus, LLC* v. *Solomon*, 766 F. 3d 241, 246 (2014).

tax rebates, that may or may not differ in important ways from the Maryland initiative." *Ibid.*

The Fourth Circuit then held that Maryland's program impermissibly conflicts with FERC policies. Maryland's program, the Fourth Circuit determined, "has the potential to seriously distort the PJM auction's price signals," undermining the incentive structure FERC has approved for construction of new generation. *Ibid.* Moreover, the Fourth Circuit explained, Maryland's program "conflicts with NEPA" by providing a 20-year price guarantee to a new entrant—even though FERC refused Maryland's request to extend the duration of the NEPA past three years. *Id.*, at 479.

We granted certiorari, 577 U. S. ___ (2015), and now affirm.

II

The Supremacy Clause makes the laws of the United States "the supreme Law of the Land; . . . any Thing in the Constitution or Laws of any State to the Contrary notwithstanding." U. S. Const., Art. VI, cl. 2. Put simply, federal law preempts contrary state law. "Our inquiry into the scope of a [federal] statute's pre-emptive effect is guided by the rule that the purpose of Congress is the ultimate touchstone in every pre-emption case." *Altria Group, Inc.* v. *Good*, 555 U. S. 70, 76 (2008) (internal quotation marks omitted). A state law is preempted where "Congress has legislated comprehensively to occupy an entire field of regulation, leaving no room for the States to supplement federal law," *Northwest Central Pipeline Corp.* v. *State Corporation Comm'n of Kan.*, 489 U. S. 493, 509 (1989), as well as "where, under the circumstances of a particular case, the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress," *Crosby* v. *National Foreign Trade Council*, 530 U. S. 363, 373 (2000) (brackets

and internal quotation marks omitted).

We agree with the Fourth Circuit's judgment that Maryland's program sets an interstate wholesale rate, contravening the FPA's division of authority between state and federal regulators. As earlier recounted, see *supra,* at 2, the FPA allocates to FERC exclusive jurisdiction over "rates and charges . . . received . . . for or in connection with" interstate wholesale sales. §824d(a). Exercising this authority, FERC has approved the PJM capacity auction as the sole ratesetting mechanism for sales of capacity to PJM, and has deemed the clearing price *per se* just and reasonable. Doubting FERC's judgment, Maryland—through the contract for differences—requires CPV to participate in the PJM capacity auction, but guarantees CPV a rate distinct from the clearing price for its interstate sales of capacity to PJM. By adjusting an interstate wholesale rate, Maryland's program invades FERC's regulatory turf. See *EPSA,* 577 U. S., at ___ (slip op., at 26) ("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." (internal quotation marks omitted)).[9]

That Maryland was attempting to encourage construction of new in-state generation does not save its program. States, of course, may regulate within the domain Congress assigned to them even when their laws incidentally

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[9] According to Maryland and CPV, the payments guaranteed under Maryland's program are consideration for CPV's compliance with various state-imposed conditions, *i.e.,* the requirements that CPV build a certain type of generator, at a particular location, that would produce a certain amount of electricity over a particular period of time. The payments, Maryland and CPV continue, are therefore separate from the rate CPV receives for its wholesale sales of capacity to PJM. But because the payments are conditioned on CPV's capacity clearing the auction—and, accordingly, on CPV selling that capacity to PJM—the payments are certainly "received . . . in connection with" interstate wholesale sales to PJM. 16 U. S. C. §824d(a).

affect areas within FERC's domain. See *Oneok, Inc.* v. *Learjet, Inc.*, 575 U. S. ___, ___ (2015) (slip op., at 11) (whether the Natural Gas Act (NGA) preempts a particular state law turns on "the *target* at which the state law *aims*").[10] But States may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC's authority over interstate wholesale rates, as Maryland has done here. See *ibid.* (distinguishing between "measures *aimed directly* at interstate purchasers and wholesalers for resale, and those aimed at subjects left to the States to regulate" (internal quotation marks omitted)).[11]

The problem we have identified with Maryland's program mirrors the problems we identified in *Mississippi Power & Light* and *Nantahala Power & Light Co.* v. *Thornburg*, 476 U. S. 953 (1986). In each of those cases, a State determined that FERC had failed to ensure the reasonableness of a wholesale rate, and the State therefore prevented a utility from recovering—through retail rates—the full cost of wholesale purchases. See *Mississippi Power & Light*, 487 U. S., at 360–364; *Nantahala*,

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[10] Although *Oneok, Inc.* v. *Learjet, Inc.*, 575 U. S. ___ (2015), involved the NGA rather than the FPA, the relevant provisions of the two statutes are analogous. This Court has routinely relied on NGA cases in determining the scope of the FPA, and vice versa. See, *e.g.*, *id.*, at 14–15 (discussing FPA cases while determining the preemptive scope of the NGA).

[11] Maryland's program, Maryland and CPV assert, is consistent with federal law because FERC has accommodated the program by eliminating the MOPR's state-supported generation exception. Even assuming that this change has prevented Maryland's program from distorting the auction's price signals, however—a point the parties dispute—Maryland cannot regulate in a domain Congress assigned to FERC and then require FERC to accommodate Maryland's intrusion. See *Northwest Central Pipeline Corp.* v. *State Corporation Comm'n of Kan.*, 489 U. S. 493, 518 (1989) ("The NGA does not require FERC to regulate around a state rule the only purpose of which is to influence purchasing decisions of interstate pipelines, however that rule is labeled.").

476 U. S., at 956–962. This Court invalidated the States' attempts to second-guess the reasonableness of interstate wholesale rates. "'Once FERC sets such a rate,'" we observed in *Mississippi Power & Light*, "'a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable. A State must rather give effect to Congress' desire to give FERC plenary authority over interstate wholesale rates, and to ensure that the States do not interfere with this authority.'" 487 U. S., at 373 (quoting *Nantahala*, 476 U. S., at 966). True, Maryland's program does not prevent a utility from recovering through retail sales a cost FERC mandated it incur—Maryland instead guarantees CPV a certain rate for capacity sales to PJM regardless of the clearing price. But *Mississippi Power & Light* and *Nantahala* make clear that States interfere with FERC's authority by disregarding interstate wholesale rates FERC has deemed just and reasonable, even when States exercise their traditional authority over retail rates or, as here, in-state generation.

The contract for differences, Maryland and CPV respond, is indistinguishable from traditional bilateral contracts for capacity, which FERC has long accommodated in the auction. See *supra*, at 4–5, and n. 3. But the contract at issue here differs from traditional bilateral contracts in this significant respect: The contract for differences does not transfer ownership of capacity from one party to another outside the auction. Instead, the contract for differences operates within the auction; it mandates that LSEs and CPV exchange money based on the cost of CPV's capacity sales to PJM. Notably, because the contract for differences does not contemplate the sale of capacity outside the auction, Maryland and CPV took the position, until the Fourth Circuit issued its decision, that the rate in the contract for differences is not subject to FERC's reasonableness review. See §824(b)(1) (FERC has jurisdiction over contracts for "*the sale of electric energy* at

wholesale in interstate commerce." (emphasis added)).[12]

Our holding is limited: We reject Maryland's program only because it disregards an interstate wholesale rate required by FERC. We therefore need not and do not address the permissibility of various other measures States might employ to encourage development of new or clean generation, including tax incentives, land grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the energy sector. Nothing in this opinion should be read to foreclose Maryland and other States from encouraging production of new or clean generation through measures "untethered to a generator's wholesale market participation." Brief for Respondents 40. So long as a State does not condition payment of funds on capacity clearing the auction, the State's program would not suffer from the fatal defect that renders Maryland's program unacceptable.[13]

* * *

For the reasons stated, the judgment of the Court of Appeals for the Fourth Circuit is

Affirmed.

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[12] Our opinion does not call into question whether generators and LSEs may enter into long-term financial hedging contracts based on the auction clearing price. Such contracts, also frequently termed contracts for differences, do not involve state action to the same degree as Maryland's program, which compels private actors (LSEs) to enter into contracts for differences—like it or not—with a generator that must sell its capacity to PJM through the auction.

[13] Because the reasons we have set out suffice to invalidate Maryland's program, we do not resolve whether, as the incumbent generators also assert, Maryland's program is preempted because it counteracts FERC's refusal to extend the NEPA's duration, or because it interferes with the capacity auction's price signals.

SUPREME COURT OF THE UNITED STATES

Nos. 14–614 and 14–623

W. KEVIN HUGHES, CHAIRMAN, MARYLAND PUBLIC SERVICE COMMISSION, ET AL., PETITIONERS
14–614 *v.*
TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL.

CPV MARYLAND, LLC, PETITIONER
14–623 *v.*
TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE FOURTH CIRCUIT

[April 19, 2016]

JUSTICE SOTOMAYOR, concurring.

I write separately to clarify my understanding of the pre-emption principles that should guide this Court's analysis of the Federal Power Act and that underpin its conclusion in these cases.

The process through which consumers obtain energy stretches across state and federal regulatory domains. The Federal Power Act authorizes the States to regulate energy production. 16 U. S. C. §824(b). It then instructs the Federal Government to step in and regulate wholesale purchases and energy transportation. §824(a). Finally, it allows the States to assume control over the ultimate sale of energy to consumers. §824(b). In short, the Federal Power Act, like all collaborative federalism statutes, envisions a federal-state relationship marked by interdependence.

Pre-emption inquiries related to such collaborative programs are particularly delicate. This Court has said that where "coordinate state and federal efforts exist within a complementary administrative framework, and in the pursuit of common purposes, the case for federal pre-emption becomes a less persuasive one." *New York State Dept. of Social Servs.* v. *Dublino*, 413 U. S. 405, 421 (1973). That is not to say that pre-emption has no role in such programs, but courts must be careful not to confuse the "congressionally designed interplay between state and federal regulation," *Northwest Central Pipeline Corp.* v. *State Corporation, Comm'n of Kan.*, 489 U. S. 493, 518 (1989), for impermissible tension that requires pre-emption under the Supremacy Clause.

In this context, therefore, our general exhortation not to rely on a talismanic pre-emption vocabulary applies with special force. See *Hines* v. *Davidowitz*, 312 U. S. 52, 67 (1941) ("This Court . . . has made use of the following expressions: conflicting; contrary to; occupying the field; repugnance; difference; irreconcilability; inconsistency; violation; curtailment; and interference. But none of these expressions provides an infallible constitutional test or an exclusive constitutional yardstick" (footnote omitted)).

I understand today's opinion to reflect these principles. Using the purpose of the Federal Power Act as the "ultimate touchstone" of its pre-emption inquiry, *Altria Group, Inc.* v. *Good*, 555 U. S. 70, 76 (2008), rather than resting on generic pre-emption frameworks unrelated to the Federal Power Act, the Court holds that Maryland has impermissibly impeded the performance of one of FERC's core regulatory duties. Ensuring "just and reasonable" wholesale rates is a central purpose of the Act. See 16 §824d(a). Pursuant to its mandate to set such rates, FERC has approved the PJM Interconnection capacity auction as the proper mechanism to determine the "just and reasonable" rate for the sale of petitioner CPV Mary-

land, LLC's energy at wholesale. *Ante*, at 12. Maryland, however, has acted to guarantee CPV a rate different from FERC's "just and reasonable" rate and has thus contravened the goals of the Federal Power Act. *Ibid.* Such actions must be preempted. *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U. S. 354, 374 (1988) ("States may not regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable wholesale rates"). The Court, however, also rightly recognizes the importance of protecting the States' ability to contribute, within their regulatory domain, to the Federal Power Act's goal of ensuring a sustainable supply of efficient and price-effective energy. *Ante*, at 15.

Endorsing those conclusions, I join the Court's opinion in full.

SUPREME COURT OF THE UNITED STATES

Nos. 14–614 and 14–623

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ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE FOURTH CIRCUIT

[April 19, 2016]

JUSTICE THOMAS, concurring in part and concurring in the judgment.

The Court concludes that Maryland's regulatory program invades the Federal Energy Regulatory Commission's (FERC) exclusive jurisdiction over interstate wholesale sales of electric energy. *Ante,* at 12. I agree that the statutory text and framework compel that conclusion, and that Maryland's program therefore cannot stand. Because the statute provides a sufficient basis for resolving these cases, I would not also rest today's holding on principles of implied pre-emption. See, *e.g., ante,* at 11–12. For that reason, I join the Court's opinion only to the extent that it rests on the text and structure of the Federal Power Act (FPA), 41 Stat. 1063, as amended, 16 U. S. C. §791a *et seq.*

The FPA divides federal and state jurisdiction over the regulation of electricity sales. As relevant here, the FPA

grants FERC the authority to regulate "the sale of electric energy at wholesale in interstate commerce." §824(b)(1). That federal authority over interstate wholesale sales is exclusive. See, *e.g.*, *Nantahala Power & Light Co.* v. *Thornburg*, 476 U. S. 953, 966 (1986) (recognizing that Congress "vested" in FERC "exclusive jurisdiction" and "plenary authority over interstate wholesale rates"); *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U. S. 354, 377 (1988) (Scalia, J., concurring in judgment) ("It is common ground that if FERC has jurisdiction over a subject, the States cannot have jurisdiction over the same subject").

To resolve these cases, it is enough to conclude that Maryland's program invades FERC's exclusive jurisdiction. Maryland has partially displaced the FERC-endorsed market mechanism for determining wholesale capacity rates. Under Maryland's program, CPV Maryland, LLC, is entitled to receive, for its wholesale sales into the capacity auction, something other than what FERC has decided that generators should receive. That is a regulation of wholesale sales: By "fiddling with the effective . . . price" that CPV receives for its wholesale sales, Maryland has "regulate[d]" wholesale sales "no less than does direct ratesetting." *FERC* v. *Electric Power Supply Assn.*, 577 U. S. ___, ___ (2016) (Scalia, J., dissenting) (slip op., at 6) (emphasis deleted) (addressing analogous situation involving retail sales). Maryland's program therefore intrudes on the exclusive federal jurisdiction over wholesale electricity rates.

Although the Court applies the FPA's framework in reaching that conclusion, see *ante,* at 12, it also relies on principles of implied pre-emption, see, *e.g., ante,* at 11–12. Because we can resolve these cases based on the statute alone, I would affirm based solely on the FPA. Accordingly, I concur in the judgment and I join the Court's opinion to the extent that it holds that Maryland's program invades FERC's exclusive jurisdiction.

ATTACHMENT C

Syllabus

NOTE: Where it is feasible, a syllabus (headnote) will be released, as is being done in connection with this case, at the time the opinion is issued. The syllabus constitutes no part of the opinion of the Court but has been prepared by the Reporter of Decisions for the convenience of the reader. See *United States* v. *Detroit Timber & Lumber Co.,* 200 U. S. 321, 337.

SUPREME COURT OF THE UNITED STATES

Syllabus

FEDERAL ENERGY REGULATORY COMMISSION *v.* ELECTRIC POWER SUPPLY ASSOCIATION ET AL.

CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT*

No. 14–840. Argued October 14, 2015—Decided January 25, 2016

The Federal Power Act (FPA) authorizes the Federal Energy Regulatory Commission (FERC) to regulate "the sale of electric energy at wholesale in interstate commerce," including both wholesale electricity rates and any rule or practice "affecting" such rates. 16 U. S. C. §§824(b), 824d(a), 824e(a). But it places beyond FERC's power, leaving to the States alone, the regulation of "any other sale"—*i.e.*, any retail sale—of electricity. §824(b).

In an increasingly competitive interstate electricity market, FERC has undertaken to ensure "just and reasonable" wholesale rates, §824d(a), by encouraging the creation of nonprofit entities to manage regions of the nationwide electricity grid. These wholesale market operators administer their portions of the grid to ensure that the network conducts electricity reliably, and each holds competitive auctions to set wholesale prices. These auctions balance supply and demand continuously by matching bids to provide electricity from generators with orders from utilities and other "load-serving entities" (LSEs) that buy power at wholesale for resale to users. All bids to supply electricity are stacked from lowest to highest, and accepted in that order until all requests for power have been met. Every electricity supplier is paid the price of the highest-accepted bid, known as the locational marginal price (LMP).

In periods of high electricity demand, prices can reach extremely

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*Together with No. 14–841, *EnerNOC, Inc., et al.* v. *Electric Power Supply Association et al.,* also on certiorari to the same court.

high levels as the least efficient generators have their supply bids accepted in the wholesale market auctions. Not only do rates rise dramatically during these peak periods, but the increased flow of electricity threatens to overload the grid and cause substantial service problems. Faced with these challenges, wholesale market operators devised wholesale demand response programs, which pay consumers for commitments to reduce their use of power during these peak periods. Just like bids to supply electricity, offers from aggregators of multiple users of electricity or large individual consumers to reduce consumption can be bid into the wholesale market auctions. When it costs less to pay consumers to refrain from using power than it does to pay producers to supply more of it, demand response can lower these wholesale prices and increase grid reliability. Wholesale operators began integrating these programs into their markets some 15 years ago and FERC authorized their use. Congress subsequently encouraged further development of demand response.

Spurred on by Congress, FERC issued Order No. 719, which, among other things, requires wholesale market operators to receive demand response bids from aggregators of electricity consumers, except when the state regulatory authority overseeing those users' retail purchases bars demand response participation. 18 CFR §35.28(g)(1). Concerned that the order had not gone far enough, FERC then issued the rule under review here, Order No. 745. §35.28(g)(1)(v) (Rule). It requires market operators to pay the same price to demand response providers for conserving energy as to generators for producing it, so long as a "net benefits test," which ensures that accepted bids actually save consumers money, is met. The Rule rejected an alternative compensation scheme that would have subtracted from LMP the savings consumers receive from not buying electricity in the retail market, a formula known as LMP-G. The Rule also rejected claims that FERC lacked statutory authority to regulate the compensation operators pay for demand response bids.

The Court of Appeals for the District of Columbia Circuit vacated the Rule, holding that FERC lacked authority to issue the order because it directly regulates the retail electricity market, and holding in the alternative that the Rule's compensation scheme is arbitrary and capricious under the Administrative Procedure Act.

Held:

1. The FPA provides FERC with the authority to regulate wholesale market operators' compensation of demand response bids. The Court's analysis proceeds in three parts. First, the practices at issue directly affect wholesale rates. Second, FERC has not regulated retail sales. Taken together, these conclusions establish that the Rule complies with the FPA's plain terms. Third, the contrary view would

conflict with the FPA's core purposes. Pp. 14–29.

(a) The practices at issue directly affect wholesale rates. The FPA has delegated to FERC the authority—and, indeed, the duty—to ensure that rules or practices "affecting" wholesale rates are just and reasonable. §§824d(a), 824e(a). To prevent the statute from assuming near-infinite breadth, see *e.g., New York State Conference of Blue Cross & Blue Shield Plans* v. *Travelers Ins. Co.*, 514 U. S. 645, 655, this Court adopts the D. C. Circuit's common-sense construction limiting FERC's "affecting" jurisdiction to rules or practices that "*directly* affect the [wholesale] rate," *California Independent System Operator Corp.* v. *FERC*, 372 F. 3d 395, 403 (emphasis added). That standard is easily met here. Wholesale demand response is all about reducing wholesale rates; so too the rules and practices that determine how those programs operate. That is particularly true here, as the formula for compensating demand response necessarily lowers wholesale electricity prices by displacing higher-priced generation bids. Pp. 14–17.

(b) The Rule also does not regulate retail electricity sales in violation of §824(b). A FERC regulation does not run afoul of §824(b)'s proscription just because it affects the quantity or terms of retail sales. Transactions occurring on the wholesale market have natural consequences at the retail level, and so too, of necessity, will FERC's regulation of those wholesale matters. That is of no legal consequence. See, *e.g., Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U. S. 354, 365, 370–373. When FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, then no matter the effect on retail rates, §824(b) imposes no bar. Here, every aspect of FERC's regulatory plan happens exclusively on the wholesale market and governs exclusively that market's rules. The Commission's justifications for regulating demand response are likewise only about improving the wholesale market. Cf. *Oneok, Inc.* v. *Learjet, Inc.*, 575 U. S. ___, ___. Pp. 17–25.

(c) In addition, EPSA's position would subvert the FPA. EPSA's arguments suggest that the entire practice of wholesale demand response falls outside what FERC can regulate, and EPSA concedes that States also lack that authority. But under the FPA, wholesale demand response programs could not go forward if no entity had jurisdiction to regulate them. That outcome would flout the FPA's core purposes of protecting "against excessive prices" and ensuring effective transmission of electric power. *Pennsylvania Water & Power Co.* v. *FPC*, 343 U. S. 414, 418; see *Gulf States Util. Co.* v. *FPC*, 411 U. S. 747, 758. The FPA should not be read, against its clear terms, to halt a practice that so evidently enables FERC to fulfill its statutory du-

ties of holding down prices and enhancing reliability in the wholesale energy market. Pp. 25–29.

2. FERC's decision to compensate demand response providers at LMP—the same price paid to generators—instead of at LMP-G, is not arbitrary and capricious. Under the narrow scope of review in *Motor Vehicle Mfrs. Assn. of United States, Inc.* v. *State Farm Mut. Automobile Ins. Co.*, 463 U. S. 29, 43, this Court's important but limited role is to ensure that FERC engaged in reasoned decisionmaking—that it weighed competing views, selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that decision. Here, FERC provided a detailed explanation of its choice of LMP and responded at length to contrary views. FERC's serious and careful discussion of the issue satisfies the arbitrary and capricious standard. Pp. 29–33.

753 F. 3d 216, reversed and remanded.

KAGAN, J., delivered the opinion of the Court, in which ROBERTS, C. J., and KENNEDY, GINSBURG, BREYER, and SOTOMAYOR, JJ., joined. SCALIA, J. filed a dissenting opinion, in which THOMAS, J., joined. ALITO, J., took no part in the consideration or decision of the cases.

NOTICE: This opinion is subject to formal revision before publication in the preliminary print of the United States Reports. Readers are requested to notify the Reporter of Decisions, Supreme Court of the United States, Washington, D. C. 20543, of any typographical or other formal errors, in order that corrections may be made before the preliminary print goes to press.

SUPREME COURT OF THE UNITED STATES

Nos. 14–840 and 14–841

FEDERAL ENERGY REGULATORY COMMISSION, PETITIONER
14–840 *v.*
ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.

ENERNOC, INC., ET AL., PETITIONERS
14–841 *v.*
ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

[January 25, 2016]

JUSTICE KAGAN delivered the opinion of the Court.

The Federal Power Act (FPA or Act), 41 Stat. 1063, as amended, 16 U. S. C. §791a *et seq.*, authorizes the Federal Energy Regulatory Commission (FERC or Commission) to regulate "the sale of electric energy at wholesale in interstate commerce," including both wholesale electricity rates and any rule or practice "affecting" such rates. §§824(b), 824e(a). But the law places beyond FERC's power, and leaves to the States alone, the regulation of "any other sale"—most notably, any retail sale—of electricity. §824(b). That statutory division generates a steady flow of jurisdictional disputes because—in point of fact if not of law—the wholesale and retail markets in electricity are inextricably linked.

These cases concern a practice called "demand re-

sponse," in which operators of wholesale markets pay electricity consumers for commitments *not* to use power at certain times. That practice arose because wholesale market operators can sometimes—say, on a muggy August day—offer electricity both more cheaply and more reliably by paying users to dial down their consumption than by paying power plants to ramp up their production. In the regulation challenged here, FERC required those market operators, in specified circumstances, to compensate the two services equivalently—that is, to pay the same price to demand response providers for conserving energy as to generators for making more of it.

Two issues are presented here. First, and fundamentally, does the FPA permit FERC to regulate these demand response transactions at all, or does any such rule impinge on the States' authority? Second, even if FERC has the requisite statutory power, did the Commission fail to justify adequately why demand response providers and electricity producers should receive the same compensation? The court below ruled against FERC on both scores. We disagree.

I

A

Federal regulation of electricity owes its beginnings to one of this Court's decisions. In the early 20th century, state and local agencies oversaw nearly all generation, transmission, and distribution of electricity. But this Court held in *Public Util. Comm'n of R. I.* v. *Attleboro Steam & Elec. Co.*, 273 U. S. 83, 89–90 (1927), that the Commerce Clause bars the States from regulating certain interstate electricity transactions, including wholesale sales (*i.e.*, sales for resale) across state lines. That ruling created what became known as the "*Attleboro* gap"—a regulatory void which, the Court pointedly noted, only Congress could fill. See *id.*, at 90.

Congress responded to that invitation by passing the FPA in 1935. The Act charged FERC's predecessor agency with undertaking "effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce." *New York* v. *FERC*, 535 U. S. 1, 6 (2002) (quoting *Gulf States Util. Co.* v. *FPC*, 411 U. S. 747, 758 (1973)). Under the statute, the Commission has authority to regulate "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce." 16 U. S. C. §824(b)(1).

In particular, the FPA obligates FERC to oversee all prices for those interstate transactions and all rules and practices affecting such prices. The statute provides that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with" interstate transmissions or wholesale sales—as well as "all rules and regulations affecting or pertaining to such rates or charges"—must be "just and reasonable." §824d(a). And if "any rate [or] charge," or "any rule, regulation, practice, or contract affecting such rate [or] charge[,]" falls short of that standard, the Commission must rectify the problem: It then shall determine what is "just and reasonable" and impose "the same by order." §824e(a).

Alongside those grants of power, however, the Act also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction. As pertinent here, §824(b)(1)—the same provision that gives FERC authority over wholesale sales—states that "this subchapter," including its delegation to FERC, "shall not apply to any other sale of electric energy." Accordingly, the Commission may not regulate either within-state wholesale sales or, more pertinent here, retail sales of electricity (*i.e.*, sales directly to users). See *New York*, 535 U. S., at 17, 23. State utility commissions continue to oversee those transactions.

Since the FPA's passage, electricity has increasingly become a competitive interstate business, and FERC's role has evolved accordingly. Decades ago, state or local utilities controlled their own power plants, transmission lines, and delivery systems, operating as vertically integrated monopolies in confined geographic areas. That is no longer so. Independent power plants now abound, and almost all electricity flows not through "the local power networks of the past," but instead through an interconnected "grid" of near-nationwide scope. See *id.*, at 7 ("electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce," linking producers and users across the country). In this new world, FERC often forgoes the cost-based rate-setting traditionally used to prevent monopolistic pricing. The Commission instead undertakes to ensure "just and reasonable" wholesale rates by enhancing competition—attempting, as we recently explained, "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 Cty.*, 554 U. S. 527, 536 (2008).

As part of that effort, FERC encouraged the creation of nonprofit entities to manage wholesale markets on a regional basis. Seven such wholesale market operators now serve areas with roughly two-thirds of the country's electricity "load" (an industry term for the amount of electricity used). See FERC, Energy Primer: A Handbook of Energy Market Basics 58–59 (Nov. 2015) (Energy Primer). Each administers a portion of the grid, providing generators with access to transmission lines and ensuring that the network conducts electricity reliably. See *ibid.* And still more important for present purposes, each operator conducts a competitive auction to set wholesale prices for electricity.

These wholesale auctions serve to balance supply and

demand on a continuous basis, producing prices for electricity that reflect its value at given locations and times throughout each day. Such a real-time mechanism is needed because, unlike most products, electricity cannot be stored effectively. Suppliers must generate—every day, hour, and minute—the exact amount of power necessary to meet demand from the utilities and other "load-serving entities" (LSEs) that buy power at wholesale for resale to users. To ensure that happens, wholesale market operators obtain (1) orders from LSEs indicating how much electricity they need at various times and (2) bids from generators specifying how much electricity they can produce at those times and how much they will charge for it. Operators accept the generators' bids in order of cost (least expensive first) until they satisfy the LSEs' total demand. The price of the last unit of electricity purchased is then paid to every supplier whose bid was accepted, regardless of its actual offer; and the total cost is split among the LSEs in proportion to how much energy they have ordered. So, for example, suppose that at 9 a.m. on August 15 four plants serving Washington, D. C. can each produce some amount of electricity for, respectively, $10/unit, $20/unit, $30/unit, and $40/unit. And suppose that LSEs' demand at that time and place is met after the operator accepts the three cheapest bids. The first three generators would then all receive $30/unit. That amount is (think back to Econ 101) the marginal cost—*i.e.,* the added cost of meeting another unit of demand—which is the price an efficient market would produce. See 1 A. Kahn, The Economics of Regulation: Principles and Institutions 65–67 (1988). FERC calls that cost (in jargon that will soon become oddly familiar) the locational marginal price, or LMP.[1]

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[1] To be more precise, LMP generally includes, in addition to the price of the highest-accepted bid, certain costs of moving power through the

As in any market, when wholesale buyers' demand for electricity increases, the price they must pay rises correspondingly; and in those times of peak load, the grid's reliability may also falter. Suppose that by 2 p.m. on August 15, it is 98 degrees in D. C. In every home, store, or office, people are turning the air conditioning up. To keep providing power to their customers, utilities and other LSEs must ask their market operator for more electricity. To meet that spike in demand, the operator will have to accept more expensive bids from suppliers. The operator, that is, will have to agree to the $40 bid that it spurned before—and maybe, beyond that, to bids of $50 or $60 or $70. In such periods, operators often must call on extremely inefficient generators whose high costs of production cause them to sit idle most of the time. See Energy Primer 41–42. As that happens, LMP—the price paid by *all* LSEs to *all* suppliers—climbs ever higher. And meanwhile, the increased flow of electricity through the grid threatens to overload transmission lines. See *id.,* at 44. As every consumer knows, it is just when the weather is hottest and the need for air conditioning most acute that blackouts, brownouts, and other service problems tend to occur.

Making matters worse, the wholesale electricity market lacks the self-correcting mechanism of other markets. Usually, when the price of a product rises, buyers naturally adjust by reducing how much they purchase. But consumers of electricity—and therefore the utilities and other LSEs buying power for them at wholesale—do not respond to price signals in that way. To use the economic term, demand for electricity is inelastic. That is in part because electricity is a necessity with few ready substitutes: When the temperature reaches 98 degrees, many people see no

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grid. But those costs are not relevant here, and we therefore disregard them.

option but to switch on the AC. And still more: Many State regulators insulate consumers from short-term fluctuations in wholesale prices by insisting that LSEs set stable retail rates. See *id.*, at 41, 43–44. That, one might say, short-circuits the normal rules of economic behavior. Even in peak periods, as costs surge in the wholesale market, consumers feel no pinch, and so keep running the AC as before. That means, in turn, that LSEs must keep buying power to send to those users—no matter that wholesale prices spiral out of control and increased usage risks overtaxing the grid.

But what if there were an alternative to that scenario? Consider what would happen if wholesale market operators could induce consumers to refrain from using (and so LSEs from buying) electricity during peak periods. Whenever doing that costs less than adding more power, an operator could bring electricity supply and demand into balance at a lower price. And simultaneously, the operator could ease pressure on the grid, thus protecting against system failures. That is the idea behind the practice at issue here: Wholesale demand response, as it is called, pays consumers for commitments to curtail their use of power, so as to curb wholesale rates and prevent grid breakdowns. See *id.*, at 44–46.[2]

These demand response programs work through the operators' regular auctions. Aggregators of multiple users of electricity, as well as large-scale individual users like factories or big-box stores, submit bids to decrease electricity consumption by a set amount at a set time for a set price. The wholesale market operators treat those offers just like bids from generators to increase supply. The

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[2] Differently designed demand response programs can operate in retail markets. Some States, for example, either encourage or require utilities to offer "critical-peak rebates" to customers for curtailing electricity use at times of high load. See Energy Primer 45.

operators, that is, rank order all the bids—both to produce and to refrain from consuming electricity—from least to most expensive, and then accept the lowest bids until supply and demand come into equipoise. And, once again, the LSEs pick up the cost of all those payments. So, to return to our prior example, if a store submitted an offer *not* to use a unit of electricity at 2 p.m. on August 15 for $35, the operator would accept that bid before calling on the generator that offered to produce a unit of power for $40. That would result in a lower LMP—again, wholesale market price—than if the market operator could not avail itself of demand response pledges. See ISO/RTO Council, Harnessing the Power of Demand: How ISOs and RTOs Are Integrating Demand Response Into Wholesale Electricity Markets 40–43 (2007) (estimating that, in one market, a demand response program reducing electricity usage by 3% in peak hours would lead to price declines of 6% to 12%). And it would decrease the risk of blackouts and other service problems.

Wholesale market operators began using demand response some 15 years ago, soon after they assumed the role of overseeing wholesale electricity sales. Recognizing the value of demand response for both system reliability and efficient pricing, they urged FERC to allow them to implement such programs. See, *e.g., PJM Interconnection, L. L. C.,* Order Accepting Tariff Sheets as Modified, 95 FERC ¶61,306 (2001); *California Independent System Operator Corp.*, Order Conditionally Accepting for Filing Tariff Revisions, 91 FERC ¶61,256 (2000). And as demand response went into effect, market participants of many kinds came to view it—in the words of respondent Electric Power Supply Association (EPSA)—as an "important element[ ] of robust, competitive wholesale electricity markets." App. 94, EPSA, Comments on Proposed Rule on Demand Response Compensation in Organized Wholesale Energy Markets (May 12, 2010).

Congress added to the chorus of voices praising wholesale demand response. In the Energy Policy Act of 2005, 119 Stat. 594 (EPAct), it declared as "the policy of the United States" that such demand response "shall be encouraged." §1252(f), 119 Stat. 966, 16 U. S. C. §2642 note. In particular, Congress directed, the deployment of "technology and devices that enable electricity customers to participate in . . . demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy . . . markets shall be eliminated." *Ibid.*[3]

B

Spurred on by Congress, the Commission determined to take a more active role in promoting wholesale demand response programs. In 2008, FERC issued Order No. 719, which (among other things) requires wholesale market operators to receive demand response bids from aggregators of electricity consumers, except when the state regulatory authority overseeing those users' retail purchases bars such demand response participation. See 73 Fed. Reg. 64119, ¶154 (codified 18 CFR §35.28(g)(1) (2015)). That original order allowed operators to compensate demand response providers differently from generators if they so chose. No party sought judicial review.

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[3]The dissent misreads this subsection of the EPAct in suggesting that it encourages States' use of retail demand response, rather than the wholesale programs at issue here. See *post,* at 8–9 (opinion of SCALIA, J.); n. 2, *supra.* The prior subsection, §1252(e), as the dissent notes, promotes demand response in the States—but then the EPAct switches gears. Subsection (f) expressly addresses the programs of "regional electricity entit[ies]"—that is, wholesale market operators. Indeed, the provision lists all the markets those operators run: not just the electricity market involved here, but also the "capacity and ancillary service markets." Those are established components of the wholesale system with no counterparts at the state level. See Energy Primer 59.

Concerned that Order No. 719 had not gone far enough, FERC issued the rule under review here in 2011, with one commissioner dissenting. See *Demand Response Competition in Organized Wholesale Energy Markets,* Order No. 745, 76 Fed. Reg. 16658 (Rule) (codified 18 CFR §35.28(g)(1)(v)). The Rule attempts to ensure "just and reasonable" wholesale rates by requiring market operators to appropriately compensate demand response providers and thus bring about "meaningful demand-side participation" in the wholesale markets. 76 Fed. Reg. 16658, ¶1, 16660, ¶10; 16 U. S. C. §824d(a). The Rule's most significant provision directs operators, under two specified conditions, to pay LMP for any accepted demand response bid, just as they do for successful supply bids. See 76 Fed. Reg. 16666–16669, ¶¶45–67. In other words, the Rule requires that demand response providers in those circumstances receive as much for conserving electricity as generators do for producing it.

The two specified conditions ensure that a bid to use less electricity provides the same value to the wholesale market as a bid to make more. First, a demand response bidder must have "the capability to provide the service" offered; it must, that is, actually be able to reduce electricity use and thereby obviate the operator's need to secure additional power. *Id.,* at 16666, ¶¶48–49. Second, paying LMP for a demand response bid "must be cost-effective," as measured by a standard called "the net benefits test." *Ibid.*, ¶48. That test makes certain that accepting a lower-priced demand response bid over a higher-priced supply bid will actually save LSEs (*i.e.*, wholesale purchasers) money. In some situations it will not, even though accepting a lower-priced bid (by definition) reduces LMP. That is because (to oversimplify a bit) LSEs share the cost of paying successful bidders, and reduced electricity use makes some LSEs drop out of the market, placing a proportionally greater burden on those that are left. Each

remaining LSE may thus wind up paying more even though the total bill is lower; or said otherwise, the costs associated with an LSE's increased share of compensating bids may exceed the savings that the LSE obtains from a lower wholesale price.[4] The net benefits test screens out such counterproductive demand response bids, exempting them from the Rule's compensation requirement. See *id.*, at 16659, 16666–16667, ¶¶3, 50–53. What remains are only those offers whose acceptance will result in actual savings to wholesale purchasers (along with more reliable service to end users). See *id.*, at 16671, ¶¶78–80.

The Rule rejected an alternative scheme for compensating demand response bids. Several commenters had urged that, in paying a demand response provider, an operator should subtract from the ordinary wholesale price the savings that the provider nets by not buying electricity on the retail market. Otherwise, the commenters claimed, demand response providers would receive a kind of "double-payment" relative to generators. See *id.*, at 16663, ¶24. That proposal, which the dissenting commissioner largely accepted, became known as LMP minus G, or more simply LMP-G, where "G" stands for the retail price of electricity. See *id.*, at 16668, ¶60, 16680 (Moeller, dissenting). But FERC explained that, under the conditions it had specified, the value of an accepted demand response bid to the wholesale market is identical to that of an accepted supply bid because each succeeds in cost-effectively "balanc[ing] supply and demand." *Id.*, at 16667, ¶55. And, the Commission reasoned, that comparable value is

[4]The explanation is a stylized version of the actual phenomenon. In reality, LSEs rarely drop out of the market entirely because of demand response; instead, they will merely order less electricity. But the effect is the same as in the text, because the total cost of accepted bids is spread among LSEs in proportion to the units of electricity they purchase; and as those units decline, each remaining one bears a greater share of the bill.

what ought to matter given FERC's goal of strengthening competition in the wholesale market: Rates should reflect not the costs that each market participant incurs, but instead the services it provides. See *id.,* at 16668, ¶62. Moreover, the Rule stated, compensating demand response bids at their actual value—*i.e.*, LMP—will help overcome various technological barriers, including a lack of needed infrastructure, that impede aggregators and large-scale users of electricity from fully participating in demand response programs. See *id.,* at 16667–16668, ¶¶57–58.

The Rule also responded to comments challenging FERC's statutory authority to regulate the compensation operators pay for demand response bids. Pointing to the Commission's analysis in Order No. 719, the Rule explained that the FPA gives FERC jurisdiction over such bids because they "directly affect[ ] wholesale rates." *Id.,* at 16676, ¶112 (citing 74 *id.*, at 37783, ¶47, and 18 U. S. C. §824d). Nonetheless, the Rule noted, FERC would continue Order No. 719's policy of allowing any state regulatory body to prohibit consumers in its retail market from taking part in wholesale demand response programs. See 76 Fed. Reg. 16676, ¶114; 73 *id.*, at 64119, ¶154. Accordingly, the Rule does not require any "action[ ] that would violate State laws or regulations." 76 *id.*, at 16676, ¶114.

C

A divided panel of the Court of Appeals for the District of Columbia Circuit vacated the Rule as "*ultra vires* agency action." 753 F. 3d 216, 225 (2014). The court held that FERC lacked authority to issue the Rule even though "demand response compensation affects the wholesale market." *Id.,* at 221. The Commission's "jurisdiction to regulate practices 'affecting' rates," the court stated, "does not erase the specific limit[ ]" that the FPA imposes on

FERC's regulation of retail sales. *Id.,* at 222. And the Rule, the court concluded, exceeds that limit: In "luring . . . *retail* customers" into the wholesale market, and causing them to decrease "levels of *retail* electricity consumption," the Rule engages in "direct regulation of the retail market." *Id.,* at 223–224.

The Court of Appeals held, alternatively, that the Rule is arbitrary and capricious under the Administrative Procedure Act, 5 U. S. C. §706(2)(A), because FERC failed to "adequately explain[ ]" why paying LMP to demand response providers "results in just compensation." 753 F. 3d, at 225. According to the court, FERC did not "properly consider" the view that such a payment would give those providers a windfall by leaving them with "the full LMP *plus* . . . the savings associated with" reduced consumption. *Ibid.* (quoting *Demand Response Competition in Organized Wholesale Energy Markets: Order on Rehearing and Clarification,* Order No. 745–A (Rehearing Order), 137 FERC ¶61,215, p. 62,316 (2011) (Moeller, dissenting)). The court dismissed out of hand the idea that "comparable contributions [could] be the reason for equal compensation." 753 F. 3d, at 225.

Judge Edwards dissented. He explained that the rules governing wholesale demand response have a "direct effect . . . on wholesale electricity rates squarely within FERC's jurisdiction." *Id.,* at 227. And in setting those rules, he argued, FERC did not engage in "direct regulation of the retail market"; rather, "[a]uthority over retail rates . . . remains vested solely in the States." *Id.,* at 234 (internal quotation marks omitted). Finally, Judge Edwards rejected the majority's view that the Rule is arbitrary and capricious. He noted the substantial deference due to the Commission in cases involving ratemaking, and concluded that FERC provided a "thorough" and "reasonable" explanation for choosing LMP as the appropriate compensation formula. *Id.,* at 236–238.

We granted certiorari, 575 U. S. ___ (2015), to decide whether the Commission has statutory authority to regulate wholesale market operators' compensation of demand response bids and, if so, whether the Rule challenged here is arbitrary and capricious. We now hold that the Commission has such power and that the Rule is adequately reasoned. We accordingly reverse.

II

Our analysis of FERC's regulatory authority proceeds in three parts. First, the practices at issue in the Rule—market operators' payments for demand response commitments—directly affect wholesale rates. Second, in addressing those practices, the Commission has not regulated retail sales. Taken together, those conclusions establish that the Rule complies with the FPA's plain terms. And third, the contrary view would conflict with the Act's core purposes by preventing all use of a tool that no one (not even EPSA) disputes will curb prices and enhance reliability in the wholesale electricity market.[5]

A

The FPA delegates responsibility to FERC to regulate the interstate wholesale market for electricity—both wholesale rates and the panoply of rules and practices affecting them. As noted earlier, the Act establishes a scheme for federal regulation of "the sale of electric energy at wholesale in interstate commerce." 16 U. S. C. §824(b)(1); see *supra,* at 3. Under the statute, "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with" interstate wholesale sales "shall be just and reasonable"; so too shall "all rules and

[5] Because we think FERC's authority clear, we need not address the Government's alternative contention that FERC's interpretation of the statute is entitled to deference under *Chevron U. S. A. Inc.* v. *Natural Resources Defense Council, Inc.*, 467 U. S. 837 (1984).

regulations affecting or pertaining to such rates or charges." §824d(a). And if FERC sees a violation of that standard, it must take remedial action. More specifically, whenever the Commission "shall find that any rate [or] charge"—or "any rule, regulation, practice, or contract affecting such rate [or] charge"—is "unjust [or] unreasonable," then the Commission "shall determine the just and reasonable rate, charge[,] rule, regulation, practice or contract" and impose "the same by order." §824e(a). That means FERC has the authority—and, indeed, the duty—to ensure that rules or practices "affecting" wholesale rates are just and reasonable.

Taken for all it is worth, that statutory grant could extend FERC's power to some surprising places. As the court below noted, markets in all electricity's inputs—steel, fuel, and labor most prominent among them—might affect generators' supply of power. See 753 F. 3d, at 221; *id.,* at 235 (Edwards, J., dissenting). And for that matter, markets in just about everything—the whole economy, as it were—might influence LSEs' demand. So if indirect or tangential impacts on wholesale electricity rates sufficed, FERC could regulate now in one industry, now in another, changing a vast array of rules and practices to implement its vision of reasonableness and justice. We cannot imagine that was what Congress had in mind.

For that reason, an earlier D. C. Circuit decision adopted, and we now approve, a common-sense construction of the FPA's language, limiting FERC's "affecting" jurisdiction to rules or practices that "*directly* affect the [wholesale] rate." *California Independent System Operator Corp.* v. *FERC,* 372 F. 3d 395, 403 (2004) (emphasis added); see 753 F. 3d, at 235 (Edwards, J., dissenting). As we have explained in addressing similar terms like "relating to" or "in connection with," a non-hyperliteral reading is needed to prevent the statute from assuming near-infinite breadth. See *New York State Conference of Blue Cross &*

Blue Shield Plans v. *Travelers Ins. Co.*, 514 U. S. 645, 655 (1995) ("If 'relate to' were taken to extend to the furthest stretch of its indeterminacy, then for all practical purposes [the statute] would never run its course"); *Maracich* v. *Spears*, 570 U. S. ___, ___ (2013) (slip op., at 9) ("The phrase 'in connection with' is essentially indeterminat[e] because connections, like relations, stop nowhere" (internal quotation marks omitted)). The Commission itself incorporated the D. C. Circuit's standard in addressing its authority to issue the Rule. See 76 Fed. Reg. 16676, ¶112 (stating that FERC has jurisdiction because wholesale demand response "directly affects wholesale rates"). We think it right to do the same.

Still, the rules governing wholesale demand response programs meet that standard with room to spare. In general (and as earlier described), wholesale market operators employ demand response bids in competitive auctions that balance wholesale supply and demand and thereby set wholesale prices. See *supra*, at 7–8. The operators accept such bids if and only if they bring down the wholesale rate by displacing higher-priced generation. And when that occurs (most often in peak periods), the easing of pressure on the grid, and the avoidance of service problems, further contributes to lower charges. See Brief for Grid Engineers et al. as *Amici Curiae* 26–27. Wholesale demand response, in short, is all about reducing wholesale rates; so too, then, the rules and practices that determine how those programs operate.

And that is particularly true of the formula that operators use to compensate demand response providers. As in other areas of life, greater pay leads to greater participation. If rewarded at LMP, rather than at some lesser amount, more demand response providers will enter more bids capable of displacing generation, thus necessarily lowering wholesale electricity prices. Further, the Commission found, heightened demand response participation

will put "downward pressure" on generators' own bids, encouraging power plants to offer their product at reduced prices lest they come away empty-handed from the bidding process. 76 Fed. Reg. 16660, ¶10. That, too, ratchets down the rates wholesale purchasers pay. Compensation for demand response thus directly affects wholesale prices. Indeed, it is hard to think of a practice that does so more.

B

The above conclusion does not end our inquiry into the Commission's statutory authority; to uphold the Rule, we also must determine that it does not regulate *retail* electricity sales. That is because, as earlier described, §824(b) "limit[s] FERC's sale jurisdiction to that at wholesale," reserving regulatory authority over retail sales (as well as intrastate wholesale sales) to the States. *New York*, 535 U. S., at 17 (emphasis deleted); see 16 U. S. C. §824(b); *supra,* at 3.[6] FERC cannot take an action transgressing that limit no matter how direct, or dramatic, its impact on wholesale rates. Suppose, to take a far-fetched example, that the Commission issued a regulation compelling every consumer to buy a certain amount of electricity on the retail market. Such a rule would necessarily determine

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[6] EPSA additionally cites §824(a) as constraining the Commission's authority, see Brief for Respondent EPSA et al. 25, 31, 43 (Brief for Respondents), but that provision adds nothing to the analysis. Section 824(a), the FPA's "declaration of policy," states that federal regulation of electricity is to "extend only to those matters which are not subject to regulation by the States." We have often explained that this declaration serves only to frame the Act's basic structure and purpose. See, *e.g., New York*, 535 U. S., at 22 (Section 824(a) "broadly expresse[s] [the Act's] purpose" (quoting *FPC* v. *Southern Cal. Edison Co.*, 376 U. S. 205, 215 (1964)); *id.*, at 215 (Section 824(a) is "merely a 'policy declaration . . . of great generality'" (quoting *Connecticut Light & Power Co.* v. *FPC*, 324 U. S. 515, 527 (1945))). That means, as applied to the issue here, that §824(a) merely points toward the division of regulatory authority that §824(b) carries out. The operative provision is what counts.

the load purchased on the wholesale market too, and thus would alter wholesale prices. But even given that ineluctable consequence, the regulation would exceed FERC's authority, as defined in §824(b), because it specifies terms of sale at retail—which is a job for the States alone.[7]

Yet a FERC regulation does not run afoul of §824(b)'s proscription just because it affects—even substantially—the quantity or terms of retail sales. It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other. To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level. And so too, of necessity, will FERC's regulation of those wholesale matters. Cf. *Oneok, Inc.* v. *Learjet, Inc.*, 575 U. S. ___, ___ (2015) (slip op., at 13) (noting that in the similarly structured world of natural gas regulation, a "Platonic ideal" of strict separation be-

[7]The dissent disputes this framing of the issue, but its criticism (made by neither EPSA nor its *amici*) is irrelevant to deciding this case. According to the dissent, the FPA prohibits FERC from regulating not only retail sales of electricity (as we agree) but also any other sales of electricity aside from wholesale sales. See *post*, at 2–4. But the dissent turns out not to argue that the Rule regulates some kind of non-retail, non-wholesale sale of electric energy (whatever that might be). Rather, the dissent claims that the Rule regulates retail sales, see *post*, at 4–6—exactly the point that we address, and reject, in the following pages. And in any event, the dissent's framing of the issue is wrong if and to the extent it posits some undefined category of other electricity sales falling within neither FERC's nor the States' regulatory authority. Sales of electric energy come in two varieties: wholesale and retail. The very case the dissent relies on recognizes that fact by referring to "other sales, that is, to direct sales for consumptive use." *Panhandle Eastern Pipe Line Co.* v. *Public Serv. Comm'n of Ind.*, 332 U. S. 507, 516 (1947). FERC regulates interstate wholesale sales of electricity; the States regulate retail sales of electricity. And FERC may also regulate, as it did here, practices and rules affecting wholesale prices—that is, matters beyond wholesale sales themselves—so long as, in doing so, it does not trespass on the States' authority to regulate retail sales of electric power. See *supra*, at 3.

tween federal and state realms cannot exist). When FERC sets a wholesale rate, when it changes wholesale market rules, when it allocates electricity as between wholesale purchasers—in short, when it takes virtually any action respecting wholesale transactions—it has some effect, in either the short or the long term, on retail rates. That is of no legal consequence. See, *e.g., Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U. S. 354, 365, 370–373 (1988) (holding that an order regulating wholesale purchases fell within FERC's jurisdiction, and preempted contrary state action, even though it clearly affected retail prices); *Nantahala Power & Light Co.* v. *Thornburg*, 476 U. S. 953, 959–961, 970 (1986) (same); *FPC* v. *Louisiana Power & Light Co.*, 406 U. S. 621, 636–641 (1972) (holding similarly in the natural gas context). When FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, then no matter the effect on retail rates, §824(b) imposes no bar.

And in setting rules for demand response, that is all FERC has done. The Commission's Rule addresses—and addresses only—transactions occurring on the wholesale market. Recall once again how demand response works—and forgive the coming italics. See *supra*, at 7–8. *Wholesale* market operators administer the entire program, receiving every demand response bid made. Those operators accept such a bid at the mandated price when (and only when) the bid provides value to the *wholesale* market by balancing supply and demand more "cost-effective[ly]"—*i.e.*, at a lower cost to *wholesale* purchasers—than a bid to generate power. 76 Fed. Reg. 16659, 16666, ¶2, 48. The compensation paid for a successful bid (LMP) is whatever the operator's auction has determined is the marginal price of *wholesale* electricity at a particular location and time. See *id.*, at 16659, ¶2. And those footing the bill are the same *wholesale* purchasers that

have benefited from the lower *wholesale* price demand response participation has produced. See *id.*, at 16674, ¶¶99–100. In sum, whatever the effects at the retail level, every aspect of the regulatory plan happens exclusively on the wholesale market and governs exclusively that market's rules.

What is more, the Commission's justifications for regulating demand response are all about, and only about, improving the wholesale market. Cf. *Oneok,* 575 U. S., at ___ (slip op., at 11) (considering "the *target* at which [a] law *aims*" in determining whether a State is properly regulating retail or, instead, improperly regulating wholesale sales). In Order No. 719, FERC explained that demand response participation could help create a "well-functioning competitive wholesale electric energy market" with "reduce[d] wholesale power prices" and "enhance[d] reliability." 73 Fed. Reg. 64103, ¶16. And in the Rule under review, FERC expanded on that theme. It listed the several ways in which "demand response in organized wholesale energy markets can help improve the functioning and competitiveness of those markets": by replacing high-priced, inefficient generation; exerting "downward pressure" on "generator bidding strategies"; and "support[ing] system reliability." 76 *id.*, at 16660, ¶10; see Notice of Proposed Rulemaking for Order No. 745, 75 *id.*, at 15363–15364, ¶4 (2010) (noting similar aims); *supra,* at 7–8. FERC, that is, focused wholly on the benefits that demand response participation (in the wholesale market) could bring to the wholesale market. The retail market figures no more in the Rule's goals than in the mechanism through which the Rule operates.

EPSA's primary argument that FERC has usurped state power (echoed in the dissent) maintains that the Rule "effectively," even though not "nominal[ly]," regulates retail prices. See, *e.g.,* Brief for Respondents 1, 10, 23–27, 35–39; Tr. of Oral Arg. 26, 30; *post,* at 4–6. The argument

begins on universally accepted ground: Under §824(b), only the States, not FERC, can set retail rates. See, *e.g.*, *FPC* v. *Conway Corp.*, 426 U. S. 271, 276 (1976). But as EPSA concedes, that tenet alone cannot make its case, because FERC's Rule does not set actual rates: States continue to make or approve all retail rates, and in doing so may insulate them from price fluctuations in the wholesale market. See Brief for Respondents 39. Still, EPSA contends, rudimentary economic analysis shows that the Rule does the "functional equivalen[t]" of setting—more particularly, of raising—retail rates. *Id.*, at 36. That is because the opportunity to make demand response bids in the wholesale market changes consumers' calculations. In deciding whether to buy electricity at retail, economically-minded consumers now consider *both* the cost of making such a purchase *and* the cost of forgoing a possible demand response payment. So, EPSA explains, if a factory can buy electricity for $10/unit, but can earn $5/unit for *not* buying power at peak times, then the effective retail rate at those times is $15/unit: the $10 the factory paid at retail plus the $5 it passed up. See *id.*, at 10. And by thus increasing effective retail rates, EPSA concludes, FERC trespasses on the States' ground.

The modifier "effective" is doing quite a lot of work in that argument—more work than any conventional understanding of rate-setting allows. The standard dictionary definition of the term "rate" (as used with reference to prices) is "[a]n amount paid or charged for a good or service." Black's Law Dictionary 1452 (10th ed. 2014); see, *e.g.*, 13 Oxford English Dictionary 208–209 (2d ed. 1989) ("rate" means "price," "cost," or "sum paid or asked for a . . . thing"). To set a retail electricity rate is thus to establish the amount of money a consumer will hand over in exchange for power. Nothing in §824(b) or any other part of the FPA suggests a more expansive notion, in which FERC sets a rate for electricity merely by altering con-

sumers' incentives to purchase that product.[8] And neither does anything in this Court's caselaw. Our decisions uniformly speak about rates, for electricity and all else, in only their most prosaic, garden-variety sense. As the Solicitor General summarized that view, "the rate is what it is." Tr. of Oral Arg. 7. It is the price paid, not the price paid *plus* the cost of a forgone economic opportunity.

Consider a familiar scenario to see what is odd about EPSA's theory. Imagine that a flight is overbooked. The airline offers passengers $300 to move to a later plane that has extra seats. On EPSA's view, that offer adds $300—the cost of not accepting the airline's proffered payment—to the price of every continuing passenger's ticket. So a person who originally spent $400 for his ticket, and decides to reject the airline's proposal, paid an "effective" price of $700. But would any passenger getting off the plane say he had paid $700 to fly? That is highly unlikely. And airline lawyers and regulators (including many, we are sure, with economics Ph. D.'s) appear to share that common-sensical view. It is in fact illegal to "increase the price" of "air transportation . . . after [such] air transportation has been purchased by the consumer." 14 CFR §399.88(a) (2015). But it is a safe bet that no airline has ever gotten into trouble by offering a payment not to fly.[9]

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[8] The dissent offers, alternatively, a definition of "price," but that only further proves our point. "Price," says the dissent, is "[t]he amount of money or other consideration asked for or given in exchange for something else." *Post,* at 6 (quoting Black's Law Dictionary 1380). But the "effective" rates posited by EPSA and the dissent do not meet that test. If $10 is the actual rate for a unit of retail electricity, that is the only amount either "asked for" or "given" in exchange for power. A retail customer is asked to pay $10 by its LSE, and if it buys that electricity, it gives the LSE that same $10. By contrast, the $15 "effective" rate is neither asked for nor given by anyone.

[9] The dissent replaces our simple, real-world example with a convoluted, fictitious one—but once again merely confirms our point. Suppose, the dissent says, that an airline cancels a passenger's $400 ticket;

And EPSA's "effective price increase" claim fares even worse when it comes to payments not to use electricity. In EPSA's universe, a wholesale demand response program raises retail rates by compelling consumers to "pay" the price of forgoing demand response compensation. But such a consumer would be even more surprised than our air traveler to learn of that price hike, because the natural consequence of wholesale demand response programs is to bring *down* retail rates. Once again, wholesale market operators accept demand response bids only if those offers lower the wholesale price. See *supra,* at 7–8. And when wholesale prices go down, retail prices tend to follow, because state regulators can, and mostly do, insist that wholesale buyers eventually pass on their savings to consumers. EPSA's theoretical construct thus runs headlong into the real world of electricity sales—where the Rule does anything but increase retail prices.

EPSA's second argument that FERC intruded into the States' sphere is more historical and purposive in nature. According to EPSA, FERC deliberately "lured [retail customers] into the[ ] wholesale markets"—and, more, FERC did so "only because [it was] dissatisfied with the States' exercise of their undoubted authority" under §824(b) to regulate retail sales. Brief for Respondents 23; see *id.,* at 2–3, 31, 34. In particular, EPSA asserts, FERC disapproved of "many States' continued preference" for stable

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gives him a refund plus an extra $300; and then tells him that if he wants to repurchase the ticket, he must pay $700. Aha!, says the dissent—isn't the price now $700? See *post,* at 5–6. Well, yes it is, because that is now the *actual* amount the passenger will have to hand over to the airline to receive a ticket in exchange (or in the dissent's definition of price, the amount "asked for" and "given," see n. 8, *supra*). In other words, in search of an intuitive way to explain its "effective rate" theory, the dissent must rely on an "actual rate" hypothetical. But all that does is highlight the distance, captured in the law, between real prices (reflecting amounts paid) and effective ones (reflecting opportunity costs).

pricing—that is, for insulating retail rates from short-term fluctuations in wholesale costs. *Id.,* at 28. In promoting demand response programs—or, in EPSA's somewhat less neutral language, in "forc[ing] retail customers to respond to wholesale price signals"—FERC acted "for the express purpose of overriding" that state policy. *Id.,* at 29, 49.

That claim initially founders on the true facts of how wholesale demand response came about. Contra EPSA, the Commission did not invent the practice. Rather, and as described earlier, the impetus came from wholesale market operators. See *supra,* at 8. In designing their newly organized markets, those operators recognized almost at once that demand response would lower wholesale electricity prices and improve the grid's reliability. So they quickly sought, and obtained, FERC's approval to institute such programs. Demand response, then, emerged not as a Commission power grab, but instead as a market-generated innovation for more optimally balancing wholesale electricity supply and demand.

And when, years later (after Congress, too, endorsed the practice), FERC began to play a more proactive role, it did so for the identical reason: to enhance the wholesale, not retail, electricity market. Like the market operators, FERC saw that sky-high demand in peak periods threatened network breakdowns, compelled purchases from inefficient generators, and consequently drove up wholesale prices. See, *e.g.,* 73 Fed. Reg. 64103, ¶16; 76 *id.,* at 16660, ¶10; see *supra,* at 6–7. Addressing those problems—which demand response does—falls within the sweet spot of FERC's statutory charge. So FERC took action promoting the practice. No doubt FERC recognized connections, running in both directions, between the States' policies and its own. The Commission understood that by insulating consumers from price fluctuations, States contributed to the wholesale market's difficulties in optimally balancing supply and demand. See 76 Fed. Reg.

16667–16668, ¶¶57, 59; *supra,* at 6–7. And FERC realized that increased use of demand response in that market would (by definition) inhibit retail sales otherwise subject to State control. See 73 Fed. Reg. 64167. But nothing supports EPSA's more feverish idea that the Commission's interest in wholesale demand response emerged from a yen to usurp State authority over, or impose its own regulatory agenda on, retail sales. In promoting demand response, FERC did no more than follow the dictates of its regulatory mission to improve the competitiveness, efficiency, and reliability of the wholesale market.

Indeed, the finishing blow to both of EPSA's arguments comes from FERC's notable solicitude toward the States. As explained earlier, the Rule allows any State regulator to prohibit its consumers from making demand response bids in the wholesale market. See 76 *id.*, at 16676, ¶114; 73 *id.*, at 64119, ¶154; *supra,* at 12. Although claiming the ability to negate such state decisions, the Commission chose not to do so in recognition of the linkage between wholesale and retail markets and the States' role in overseeing retail sales. See 76 Fed. Reg. 16676, ¶¶112–114. The veto power thus granted to the States belies EPSA's view that FERC aimed to "obliterate[ ]" their regulatory authority or "override" their pricing policies. Brief for Respondents 29, 33. And that veto gives States the means to block whatever "effective" increases in retail rates demand response programs might be thought to produce. Wholesale demand response as implemented in the Rule is a program of cooperative federalism, in which the States retain the last word. That feature of the Rule removes any conceivable doubt as to its compliance with §824(b)'s allocation of federal and state authority.

C

One last point, about how EPSA's position would subvert the FPA.

EPSA's jurisdictional claim, as may be clear by now, stretches very far. Its point is not that this single Rule, relating to compensation levels, exceeds FERC's power. Instead, EPSA's arguments—that rewarding energy conservation raises effective retail rates and that "luring" consumers onto wholesale markets aims to disrupt state policies—suggest that the entire practice of wholesale demand response falls outside what FERC can regulate. EPSA proudly embraces that point: FERC, it declares, "has no business regulating 'demand response' at all." *Id.*, at 24. Under EPSA's theory, FERC's earlier Order No. 719, although never challenged, would also be ultra vires because it requires operators to open their markets to demand response bids. And more: FERC could not even approve an operator's voluntary plan to administer a demand response program. See Tr. of Oral Arg. 44. That too would improperly allow a retail customer to participate in a wholesale market.

Yet state commissions could not regulate demand response bids either. EPSA essentially concedes this point. See Brief for Respondents 46 ("That may well be true"). And so it must. 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." *Northern Natural Gas Co.* v. *State Corporation Comm'n of Kan.*, 372 U. S. 84, 91 (1963). A State could not oversee offers, made in a wholesale market operator's auction, that help to set wholesale prices. Any effort of that kind would be preempted.

And all of that creates a problem. If neither FERC nor the States can regulate wholesale demand response, then by definition no one can. But under the Act, no electricity transaction can proceed unless it is regulable by someone. As earlier described, Congress passed the FPA precisely to eliminate vacuums of authority over the electricity markets. See *supra,* at 2–3. The Act makes federal and state

powers "complementary" and "comprehensive," so that "there [will] be no 'gaps' for private interests to subvert the public welfare." *Louisiana Power & Light Co.*, 406 U. S., at 631. Or said otherwise, the statute prevents the creation of any regulatory "no man's land." *FPC* v. *Transcontinental Gas Pipe Line Corp.*, 365 U. S. 1, 19 (1961); see *id.*, at 28. Some entity must have jurisdiction to regulate each and every practice that takes place in the electricity markets, demand response no less than any other.[10]

For that reason, the upshot of EPSA's view would be to extinguish the wholesale demand response program in its entirety. Under the FPA, each market operator must submit to FERC all its proposed rules and procedures. See 16 U. S. C. §§824d(c)–(d); 18 CFR §§35.28(c)(4), 35.3(a)(1). Assume that, as EPSA argues, FERC could not authorize any demand response program as part of that package. Nor could FERC simply allow such plans to go into effect without its consideration and approval. There are no "off the books" programs in the wholesale electricity markets—because, once again, there is no regulatory "no man's land." *Transcontinental*, 365 U. S., at 19. The FPA mandates that FERC review, and ensure the reasonable-

[10]The dissent contests this point (complaining that our decades' worth of precedents affirming it partly rely on legislative history), but the example the dissent offers in response misses the mark. See *post*, at 7–8. The dissent hypothesizes a rule enabling generators to sell directly to consumers and fixing all generation, transmission, and retail rates. But of course neither FERC nor the States could issue such a rule: If FERC did so, it would interfere with the States' authority over retail sales and rates as well as (most) generation; if a State did so, it would interfere with FERC's power over transmission. Thus, to implement such a scheme, the States would need to do some things and FERC to do others. And if the one or the other declined to cooperate, then the full scheme could not proceed. But that just goes to show that the FPA divides regulatory power over electricity matters between FERC and the States. The example does nothing to demonstrate that some electricity transactions can proceed outside any regulator's authority.

ness of, every wholesale rule and practice. See 16 U. S. C. §§824d(a), 824e(a); *supra,* at 3, 14–15. If FERC could not carry out that duty for demand response, then those programs could not go forward.

And that outcome would flout the FPA's core objects. The statute aims to protect "against excessive prices" and ensure effective transmission of electric power. *Pennsylvania Water & Power Co.* v. *FPC,* 343 U. S. 414, 418 (1952); see *Gulf States Util. Co.* v. *FPC,* 411 U. S. 747, 758 (1973). As shown above, FERC has amply explained how wholesale demand response helps to achieve those ends, by bringing down costs and preventing service interruptions in peak periods. See *supra,* at 20. No one taking part in the rulemaking process—not even EPSA—seriously challenged that account. Even as he objected to FERC's compensation formula, Commissioner Moeller noted the unanimity of opinion as to demand response's value: "[N]owhere did I review any comment or hear any testimony that questioned the benefit of having demand response resources participate in the organized wholesale energy markets. On this point, there is no debate." 76 Fed. Reg. 16679; see also App. 82, EPSA, Comments on Proposed Rule (avowing "full[ ] support" for demand response participation in wholesale markets because of its "economic and operational" benefits).[11] Congress itself

[11]EPSA now contends that wholesale demand response is unnecessary because state regulators can adopt programs to reduce demand at the retail level. See Brief for Respondents 46–47. For example, States can insist that utilities give rebates to customers for not using energy at certain times. See n. 2, *supra.* But according to both the Commission and market participants, state-level programs cannot offer nearly the same benefits as wholesale demand response because individual utilities lack the regional scope and real-time information needed to identify when demand response will lower prices and ensure reliability system-wide. See 73 Fed. Reg. 64103, ¶18; Energy Primer 45–46; Brief for NRG Energy, Inc., as *Amicus Curiae* 20–22. Similarly, FERC addressed and rejected the dissent's suggestion that wholesale market

agreed, "encourag[ing]" greater use of demand response participation at the wholesale level. EPAct §1252(f), 119 Stat. 966. That undisputed judgment extinguishes any last flicker of life in EPSA's argument. We will not read the FPA, against its clear terms, to halt a practice that so evidently enables the Commission to fulfill its statutory duties of holding down prices and enhancing reliability in the wholesale energy market.

III

These cases present a second, narrower question: Is FERC's decision to compensate demand response providers at LMP—the same price paid to generators—arbitrary and capricious? Recall here the basic issue. See *supra,* at 9–12. Wholesale market operators pay a single price—LMP—for all successful bids to supply electricity at a given time and place. The Rule orders operators to pay the identical price for a successful bid to conserve electricity so long as that bid can satisfy a "net benefits test"—meaning that it is sure to bring down costs for wholesale purchasers. In mandating that payment, FERC rejected an alternative proposal under which demand response providers would receive LMP minus G (LMP-G), where G is the retail rate for electricity. According to EPSA and others favoring that approach, demand response providers get a windfall—a kind of "double-payment"—unless market operators subtract the savings associated with conserving electricity from the ordinary compensation level. 76 Fed. Reg. 16663, ¶24. EPSA now claims that FERC failed to adequately justify its choice of LMP rather than

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operators could pay LSEs to reduce their electricity purchases: Because LSEs lose revenues whenever demand goes down, any demand response programs targeting those actors would be highly inefficient. See FERC, Assessment of Demand Response and Advanced Metering 72 (2006); Tr. of Oral Arg. 56 (Solicitor General noting that LSEs engaged in demand response would be "cannibaliz[ing] their own profits").

LMP-G.

In reviewing that decision, we may not substitute our own judgment for that of the Commission. The "scope of review under the 'arbitrary and capricious' standard is narrow." *Motor Vehicle Mfrs. Assn. of United States, Inc.* v. *State Farm Mut. Automobile Ins. Co.*, 463 U. S. 29, 43 (1983). A court is not to ask whether a regulatory decision is the best one possible or even whether it is better than the alternatives. Rather, the court must uphold a rule if the agency has "examine[d] the relevant [considerations] and articulate[d] a satisfactory explanation for its action[,] including a rational connection between the facts found and the choice made." *Ibid.* (internal quotation marks omitted). And nowhere is that more true than in a technical area like electricity rate design: "[W]e afford great deference to the Commission in its rate decisions." *Morgan Stanley*, 554 U. S., at 532.

Here, the Commission gave a detailed explanation of its choice of LMP. See 76 Fed. Reg. 16661–16669, ¶¶18–67. Relying on an eminent regulatory economist's views, FERC chiefly reasoned that demand response bids should get the same compensation as generators' bids because both provide the same value to a wholesale market. See *id.*, at 16662–16664, 16667–16668, ¶¶20, 31, 57, 61; see also App. 829–851, Reply Affidavit of Dr. Alfred E. Kahn (Aug. 30, 2010) (Kahn Affidavit). FERC noted that a market operator needs to constantly balance supply and demand, and that either kind of bid can perform that service cost-effectively—*i.e.*, in a way that lowers costs for wholesale purchasers. See 76 Fed. Reg. 16667–16668, ¶¶56, 61. A compensation system, FERC concluded, therefore should place the two kinds of bids "on a competitive par." *Id.*, at 16668, ¶61 (quoting Kahn Affidavit); see also App. 830, Kahn Affidavit (stating that "economic efficiency requires" compensating the two equally given their equivalent function in a "competitive power mar-

ket[ ]"). With both supply and demand response available on equal terms, the operator will select whichever bids, of whichever kind, provide the needed electricity at the lowest possible cost. See Rehearing Order, 137 FERC, at 62,301–62,302, ¶68 ("By ensuring that both . . . receive the same compensation for the same service, we expect the Final Rule to enhance the competitiveness" of wholesale markets and "result in just and reasonable rates").

That rationale received added support from FERC's adoption of the net benefits test. The Commission realized during its rulemaking that in some circumstances a demand response bid—despite reducing the wholesale rate—does *not* provide the same value as generation. See 76 Fed. Reg. 16664–16665, ¶38. As described earlier, that happens when the distinctive costs associated with compensating a demand response bid exceed the savings from a lower wholesale rate: The purchaser then winds up paying more than if the operator had accepted the best (even though higher priced) supply bid available. See *supra,* at 10–11. And so FERC developed the net benefits test to filter out such cases. See 76 Fed. Reg. 16666–16667, ¶¶50–53. With that standard in place, LMP is paid only to demand response bids that benefit wholesale purchasers—in other words, to those that function as "cost-effective alternative[s] to the next highest-bid generation." *Id.,* at 16667, ¶54. Thus, under the Commission's approach, a demand response provider will receive the same compensation as a generator only when it is in fact providing the same service to the wholesale market. See *ibid.,* ¶53.

The Commission responded at length to EPSA's contrary view that paying LMP, even in that situation, will overcompensate demand response providers because they are also "effectively receiv[ing] 'G,' the retail rate that they do not need to pay." *Id.,* at 16668, ¶60. FERC explained that compensation ordinarily reflects only the value of the

service an entity provides—not the costs it incurs, or benefits it obtains, in the process. So when a generator presents a bid, "the Commission does not inquire into the costs or benefits of production." *Ibid.*, ¶62. Different power plants have different cost structures. And, indeed, some plants receive tax credits and similar incentive payments for their activities, while others do not. See Rehearing Order, 137 FERC, at 62,301, ¶65, and n. 122. But the Commission had long since decided that such matters are irrelevant: Paying LMP to all generators—although some then walk away with more profit and some with less—"encourages more efficient supply and demand decisions." 76 Fed. Reg. 16668, ¶62 (internal quotation marks omitted). And the Commission could see no economic reason to treat demand response providers any differently. Like generators, they too experience a range of benefits and costs—both the benefits of not paying for electricity and the costs of not using it at a certain time. But, FERC again concluded, that is immaterial: To increase competition and optimally balance supply and demand, market operators should compensate demand response providers, like generators, based on their contribution to the wholesale system. See *ibid.*; 137 FERC, at 62,300, ¶60.

Moreover, FERC found, paying LMP will help demand response providers overcome certain barriers to participation in the wholesale market. See 76 Fed. Reg. 16667–16668, ¶¶57–59. Commenters had detailed significant start-up expenses associated with demand response, including the cost of installing necessary metering technology and energy management systems. See *id.,* at 16661, ¶18, 16667–16668, ¶57; see also, *e.g.,* App. 356, Viridity Energy, Inc., Comments on Proposed Rule on Demand Response Compensation in Organized Wholesale Energy Markets (May 13, 2010) (noting the "capital investments and operational changes needed" for demand response

participation). The Commission agreed that such factors inhibit potential demand responders from competing with generators in the wholesale markets. See 76 Fed. Reg. 16668, ¶59. It concluded that rewarding demand response at LMP (which is, in any event, the price reflecting its value to the market) will encourage that competition and, in turn, bring down wholesale prices. See *ibid.*

Finally, the Commission noted that determining the "G" in the formula LMP-G is easier proposed than accomplished. See *ibid.*, ¶63. Retail rates vary across and even within States, and change over time as well. Accordingly, FERC concluded, requiring market operators to incorporate G into their prices, "even though perhaps feasible," would "create practical difficulties." *Ibid.* Better, then, not to impose that administrative burden.

All of that together is enough. The Commission, not this or any other court, regulates electricity rates. The disputed question here involves both technical understanding and policy judgment. The Commission addressed that issue seriously and carefully, providing reasons in support of its position and responding to the principal alternative advanced. In upholding that action, we do not discount the cogency of EPSA's arguments in favor of LMP-G. Nor do we say that in opting for LMP instead, FERC made the better call. It is not our job to render that judgment, on which reasonable minds can differ. Our important but limited role is to ensure that the Commission engaged in reasoned decisionmaking—that it weighed competing views, selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that choice. FERC satisfied that standard.

IV

FERC's statutory authority extends to the Rule at issue here addressing wholesale demand response. The Rule

governs a practice directly affecting wholesale electricity rates. And although (inevitably) influencing the retail market too, the Rule does not intrude on the States' power to regulate retail sales. FERC set the terms of transactions occurring in the organized wholesale markets, so as to ensure the reasonableness of wholesale prices and the reliability of the interstate grid—just as the FPA contemplates. And in choosing a compensation formula, the Commission met its duty of reasoned judgment. FERC took full account of the alternative policies proposed, and adequately supported and explained its decision. Accordingly, we reverse the judgment of the Court of Appeals for the District of Columbia Circuit and remand the cases for further proceedings consistent with this opinion.

It is so ordered.

JUSTICE ALITO took no part in the consideration or decision of these cases.

SUPREME COURT OF THE UNITED STATES

Nos. 14–840 and 14–841

FEDERAL ENERGY REGULATORY COMMISSION, PETITIONER
14–840 *v.*
ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.

ENERNOC, INC., ET AL., PETITIONERS
14–841 *v.*
ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

[January 25, 2016]

JUSTICE SCALIA, with whom JUSTICE THOMAS joins, dissenting.

I believe the Federal Power Act (FPA or Act), 16 U. S. C. §791a *et seq.*, prohibits the Federal Energy Regulatory Commission (FERC) from regulating the demand response of retail purchasers of power. I respectfully dissent from the Court's holding to the contrary.

I

A

I agree with the majority that FERC has the authority to regulate practices "affecting" wholesale rates. §§824d(a), 824e(a); *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore,* 487 U. S. 354, 371 (1988). I also agree that this so-called "affecting" jurisdiction cannot be limitless. And I suppose I could even live with the Court's "direct effect" test as a reasonable limit. *Ante,* at 15. But as the majority recognizes, *ante,* at 17, that extratextual limit on the "affecting" jurisdiction merely supplements,

not supplants, limits that are already contained in the statutory text and structure. I believe the Court misconstrues the primary statutory limit. (Like the majority, I think that deference under *Chevron U. S. A. Inc.* v. *Natural Resources Defense Council, Inc.*, 467 U. S. 837 (1984), is unwarranted because the statute is clear.)

The Act grants FERC authority to regulate the "generation . . . [and] transmission of electric energy in interstate commerce and the sale of such energy at wholesale." §824(a). Yet the majority frames the issue thusly: "[T]o uphold the [r]ule, we also must determine that it does not regulate *retail* electricity sales." *Ante,* at 17. That formulation inverts the proper inquiry. The pertinent question under the Act is whether the rule regulates sales "*at wholesale.*" If so, it falls within FERC's regulatory authority. If not, the rule is unauthorized whether or not it happens to regulate "*retail* electricity sales"; for, with exceptions not material here, the FPA prohibits FERC from regulating "*any other* sale of electric energy" that is *not* at wholesale. §824(b)(1) (emphasis added). (The majority wisely ignores FERC's specious argument that the demand-response rule does not regulate any sale, wholesale or retail. See Brief for Petitioner in No. 14–840, p. 39. Paying someone *not* to conclude a transaction that otherwise would without a doubt have been concluded is most assuredly a regulation of that transaction. Cf. *Gonzales* v. *Raich*, 545 U. S. 1, 39–40 (2005) (SCALIA, J., concurring in judgment).)

Properly framing the inquiry matters not because I think there exists "some undefined category of . . . electricity sales" that is "non-retail [and] non-wholesale," *ante,* at 18, n. 7,* but because a proper framing of the inquiry is

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*Although the majority dismisses this possibility, in fact it appears to think that demand response is in that category: It rejects the conclusion that the demand-response rule regulates retail sales, *ante,* at 17–23,

important to establish the default presumption regarding the scope of FERC's authority. While the majority would find every sale of electric energy to be *within* FERC's authority to regulate *unless* the transaction is demonstrably a retail sale, the statute actually *excludes* from FERC's jurisdiction all sales of electric energy *except* those that are demonstrably sales at wholesale.

So what, exactly, is a "sale of electric energy at wholesale"? We need not guess, for the Act provides a definition: "a sale of electric energy to any person *for resale*." §824(d) (emphasis added). No matter how many times the majority incants and italicizes the word "wholesale," *ante,* at 19–20, nothing can change the fact that the vast majority of (and likely all) demand-response participants—"[a]ggregators of multiple users of electricity, as well as large-scale individual users like factories or big-box stores," *ante,* at 7—*do not resell electric energy*; they consume it themselves. FERC's own definition of demand response is aimed at energy *consumers,* not resellers. 18 CFR §35.28(b)(4) (2015).

It is therefore quite beside the point that the challenged "[r]ule addresses—and addresses only—transactions occurring on the wholesale market," *ante,* at 19. For FERC's regulatory authority over electric-energy sales depends not on which "market" the "transactions occu[r] on" (whatever that means), but rather on the *identity of the putative purchaser.* If the purchaser is one who resells electric energy to other customers, the transaction is one "at wholesale" and thus within FERC's authority. If not, then not. Or so, at least, says the statute. As we long ago said of the parallel provision in the Natural Gas Act, 15 U. S. C. §717, "[t]he line of the statute [i]s thus clear and

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yet also implicitly rejects the conclusion that it regulates wholesale sales—otherwise why rely on FERC's "affecting" jurisdiction to rescue the rule's legitimacy?

complete. It cut[s] sharply and cleanly between sales for resale and direct sales for consumptive uses. No exceptions [a]re made in either category for particular uses, quantities, or otherwise." *Panhandle Eastern Pipe Line Co.* v. *Public Serv. Comm'n of Ind.*, 332 U. S. 507, 517 (1947). The majority makes no textual response to this plain reading of the statute.

The demand-response bidders here indisputably do not resell energy to other customers. It follows that the rule does not regulate electric-energy sales "at wholesale," and 16 U. S. C. §824(b)(1) therefore forbids FERC to regulate these demand-response transactions. See *New York* v. *FERC*, 535 U. S. 1, 17 (2002). That is so whether or not those transactions "directly affect" wholesale rates; as we recently said in another context, we will not adopt a construction that "needlessly produces a contradiction in the statutory text." *Shapiro* v. *McManus*, 577 U. S. ___, ___ (2015) (slip op., at 4). A faithful application of that principle would compel the conclusion that FERC may not "do under [§§824d(a) and 824e(a)] what [it] is forbidden to do under [§824(b)(1)]." *Id.*, at ___ (slip op., at 5).

B

The analysis could stop there. But the majority is wrong even on its own terms, for the rule at issue here does in fact regulate "*retail* electricity sales," which are indisputably "matters . . . subject to regulation by the States" and therefore off-limits to FERC. §824(a); see *FPC* v. *Conway Corp.*, 426 U. S. 271, 276 (1976); *Panhandle Eastern Pipe Line Co.*, *supra*, at 517–518. The demand-response participants are retail customers—they purchase electric energy solely for their own consumption. And FERC's demand-response scheme is intentionally "designed to induce lower consumption of electric energy"—in other words, to induce a reduction in "*retail* electricity sales"—by offering "incentive payments" to those custom-

ers. 18 CFR §35.28(b)(4). The incentive payments effectively increase the retail price of electric energy for participating customers because they must now account for the opportunity cost of using, as opposed to abstaining from using, more energy. In other words, it literally *costs them more* to buy energy on the retail market. In the court below, FERC conceded that offering *credits* to retail customers to reduce their electricity consumption "would be an impermissible intrusion into the retail market" because it would in effect regulate retail rates. 753 F. 3d 216, 223 (CADC 2014). Demand-response incentive payments are identical in substance.

The majority resists this elementary economic conclusion (notwithstanding its own exhortation to "think back to Econ 101," *ante,* at 5). Why? Because its self-proclaimed "common-sensical" view dictates otherwise. *Ante,* at 22. Maybe the easiest way to see the majority's error is to take its own example: an airline passenger who rejects a $300 voucher for taking a later flight. Consider the following formulation of that example, indistinguishable in substance from the majority's formulation. (Indistinguishable because the hypothetical passenger has exactly the same options and outcomes available to him.) Suppose the airline said to the passenger: "We have proactively canceled your ticket and refunded $400 to your account; and because we have inconvenienced you, we have also deposited an extra $300. The money is yours to use as you like. But if you insist on repurchasing a ticket on the same flight, you must not only pay us $400, but return the $300 too." *Now* what is the effective price of the ticket? Sometimes an allegedly commonsensical intuition is just that—an intuition, often mistaken.

Moving closer to home, recall that demand-response participants must choose either to purchase a unit of energy at the prevailing retail price (say $10) or to withhold from purchasing that unit and receive instead an

incentive payment (of say $5). The two options thus present a choice between having a unit of energy, on the one hand, and having $15 more in the bank, on the other. To repeat: take the energy, be $15 poorer; forgo the energy, be $15 richer. Is that not the very definition of price? See Black's Law Dictionary 1380 (10th ed. 2014) ("[t]he amount of money or other consideration asked for or given in exchange for something else"). In fact, is that not *the majority*'s definition of price? *Ante,* at 21 ("the amount of money a consumer will hand over in exchange for power").

In any event, the majority appears to recognize that the effective price is indeed $15—just as the effective price of the airline ticket in the hypothetical is $700. *Ante,* at 22–23, n. 9. That recognition gives away the game. For FERC is prohibited not just from directly setting or modifying retail *prices*; it is prohibited from regulating retail *sales*, no matter the means. *Panhandle Eastern Pipe Line Co.*, *supra,* at 517. Whether FERC sets the "real" retail price (to use the majority's idiosyncratic terminology, *ante,* at 23, n. 9) or the "effective" retail price is immaterial; either way, the rule—*by design*—induces demand-response participants to forgo retail electric-energy purchases they otherwise would have made. As noted, even FERC conceded that offering credits to retail customers would impermissibly regulate retail sales. The majority blithely overlooks this concession in favor of its own myopic view of retail pricing—all the while evading the inconvenient fact that fiddling with the effective retail price of electric energy, be it through incentive payments or hypothetical credits, *regulates retail sales* of electric energy no less than does direct ratesetting.

C

The majority cites dicta in several of our opinions expressing the assumption that state jurisdiction and federal jurisdiction under FERC cover the field, so that there is no

regulatory "gap"; one entity or the other "must have jurisdiction to regulate each and every practice that takes place in the electricity markets." *Ante*, at 27. The cases that express such a principle, with respect to the Federal Power Act and its companion the Natural Gas Act, base it (no surprise) on legislative history. See, *e.g.*, *FPC* v. *Louisiana Power & Light Co.*, 406 U. S. 621, 631 (1972); *FPC* v. *Transcontinental Gas Pipe Line Corp.*, 365 U. S. 1, 19 (1961); *Panhandle Eastern Pipe Line Co.*, 332 U. S., at 517–518, and n. 13. One would *expect* the congressional proponents of legislation to assert that it is "comprehensive" and leaves no stone unturned. But even if one is a fan of legislative history, surely one cannot rely upon such generalities in determining what a statute actually *does*. Whether it is "comprehensive" and leaves not even the most minor regulatory "gap" surely depends on what it says and not on what its proponents hoped to achieve. I cannot imagine a more irrational interpretive principle than the following, upon which the majority evidently relies:

> "[W]hen a dispute arises over whether a given transaction is within the scope of federal or state regulatory authority, we are not inclined to approach the problem negatively, thus raising the possibility that a 'no man's land' will be created. That is to say, in a borderline case where congressional authority is not explicit we must ask whether state authority can practicably regulate a given area and, if we find that it cannot, then we are impelled to decide that federal authority governs." *Transcontinental Gas Pipe Line Corp.*, *supra*, at 19–20 (citation omitted).

That extravagant and otherwise-unheard-of method of establishing regulatory jurisdiction was not necessary to the judgments that invoked it, and should disappear in the Court's memory hole.

Suppose FERC decides that eliminating the middleman would benefit the public, and therefore promulgates a rule allowing electric-energy generators to sell directly to retail consumers across state lines and fixing generation, transmission, and retail rates for such sales. I think it obvious this hypothetical scheme would be forbidden to FERC. Yet just as surely the States could not enact it either, for only FERC has authority to regulate "the transmission of electric energy in interstate commerce." 16 U. S. C. §824(b)(1); see also *New York*, 535 U. S., at 19–20. Is this a regulatory "gap"? Has the generator-to-consumer sales scheme fallen into a regulatory "no man's land"? *Must* FERC therefore be allowed to implement this scheme on its own? Applying the majority's *logic* would yield nothing but "yesses." Yet the majority acknowledges that neither FERC nor the States have regulatory jurisdiction over this scheme. *Ante*, at 27, n. 10. Such sales transactions, involving a mix of retail and wholesale players—*as the demand-response scheme does*—can be regulated (if at all) only by joint action. I would not call that a "problem," *ante*, at 26; I would call it an inevitable consequence of the federal-state division created by the FPA.

The majority is evidently distraught that affirming the decision below "would . . . extinguish the wholesale demand response program in its entirety." *Ante*, at 27. Alarmist hyperbole. Excluding FERC jurisdiction would at most eliminate *this particular flavor* of FERC-regulated demand response. Nothing prevents FERC from tweaking its demand-response scheme by requiring incentive payments to be offered to *wholesale* customers, rather than retail ones. Brief for Respondent Electric Power Supply Assn. (EPSA) et al. 47–48; Brief for Respondents Midwest Load-Serving Entities 10–11. And retail-level demand-response programs, run by the States, do and would continue to exist. See Brief for Respondent EPSA et al. 46–47; Brief for Respondents Midwest Load-Serving Entities

6–11. In fact Congress seemed to presuppose that *States*, not FERC, would run such programs: The relevant provisions of the Energy Policy Act of 2005, 119 Stat. 594 *et seq.*, are intended "to encourage *States* to coordinate, on a regional basis, *State* energy policies to provide reliable and affordable demand response services." §1252(e)(1), *id.,* at 965, codified at 16 U. S. C. §2642 note (emphasis added). That statute also imposes several duties on the Secretary of Energy to assist States in implementing demand-response programs. §§1252(e)(2), (e)(3), 119 Stat. 965–966. In context, §1252(f) of the 2005 Act is therefore best read as directing the Secretary to eliminate "unnecessary barriers" to *States'* adopting and implementing demand-response systems—and not, as the majority contends, as "praising *wholesale* demand response" systems to be deployed and regulated by FERC, *ante,* at 9 (emphasis added).

Moreover, the rule itself allows States to forbid their retail customers to participate in the existing demand-response scheme. 18 CFR §35.28(g)(1)(i)(A); see Brief for Petitioner in No. 14–840, at 43. The majority accepts FERC's argument that this is merely a matter of grace, and claims that it puts the "finishing blow" to respondents' argument that 16 U. S. C. §824(b)(1) prohibits the scheme. *Ante,* at 25. Quite the contrary. Remember that the majority believes FERC's authority derives from 16 U. S. C. §§824d(a) and 824e(a), the grants of "affecting" jurisdiction. Yet those provisions impose a *duty* on FERC to ensure that "all rules and regulations affecting or pertaining to [wholesale] rates or charges *shall be just and reasonable.*" §824d(a) (emphasis added); see §824e(a) (similar); *Conway Corp.*, 426 U. S., at 277–279. If inducing retail customers to participate in wholesale demand-response transactions is necessary to render wholesale rates "just and reasonable," how can FERC, consistent with its statutory mandate, permit States to thwart such

participation? See Brief for United States as *Amicus Curiae* 20–21, in *Hughes* v. *Talen Energy Marketing, LLC,* No. 14–614 etc., now pending before the Court (making an argument similar to ours); cf. *New England Power Co.* v. *New Hampshire,* 455 U. S. 331, 339–341 (1982). Although not legally relevant, the fact that FERC—ordinarily so jealous of its regulatory authority, see Brief for United States as *Amicus Curiae* in No. 14–614 etc.—is willing to let States opt out of its demand-response scheme serves to highlight just how far the rule intrudes into the retail electricity market.

II

Having found the rule to be within FERC's authority, the Court goes on to hold that FERC's choice of compensating demand-response bidders with the "locational marginal price" is not arbitrary and capricious. There are strong arguments that it is. Brief for Robert L. Borlick et al. as *Amici Curiae* 5–34. Since, however, I believe FERC's rule is ultra vires I have neither need nor desire to analyze whether, if it were not ultra vires, it would be reasonable.

* * *

For the foregoing reasons, I respectfully dissent.