ORAL ARGUMENT IS SCHEDULED FOR APRIL 18, 2005

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 03-1292, *et al.*

PPL WALLINGFORD ENERGY LLC, *et al.*
PETITIONERS,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT.

ON PETITION FOR REVIEW OF ORDERS OF THE
FEDERAL ENERGY REGULATORY COMMISSION

BRIEF FOR RESPONDENT FEDERAL ENERGY REGULATORY COMMISSION

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JURISDICTIONAL STATEMENT

Petitioners have filed two separate petitions, each of which seeks judicial review under Section 313(b) of the Federal Power Act ("FPA"), 16 U.S.C. § 825*l*(b), of a separate set of FERC orders. The petition in No. 03-1292 seeks review of *Devon Power LLC*, 103 FERC ¶ 61,082 (JA 237-45), *order on reh'g*, 104 FERC ¶ 61,123 (2003) (JA 339-52); the petition in No. 04-1062, of *PPL Wallingford Energy LLC*, 103 FERC ¶ 61,185 (JA 246-49), *order on reh'g*, 105 FERC ¶ 61,324 (2003) (JA 412-

18).[1] The Court lacks jurisdiction over the petition in No. 03-1292 because Petitioners are not "aggrieved" by the *Devon* orders within the meaning of FPA § 313(b).[2]

STATEMENT OF THE ISSUES

1. Should the petition for review in No. 03-1292 be dismissed for lack of jurisdiction on the ground that the *Devon* orders do not aggrieve Petitioners?

2. Assuming jurisdiction, did the *Devon* orders reasonably reject "reliability must-run" ("RMR") cost-of-service agreements filed under FPA § 205(e), 16 U.S.C. §

[1] All *FERC Reports* citations captioned *Devon Power LLC* are captioned herein as "*Devon*"; all *FERC Reports* citations captioned *Wallingford Energy LLC* are captioned herein as "*Wallingford*."

[2] The petition in No. 03-1292 sought review of orders in the *Devon* proceeding issued on March 25 (102 FERC ¶ 61,314 (2003) (JA 200-02)), April 25 (103 FERC ¶ 61,082 (JA 237-45)) and July 24, 2003 (104 FERC ¶ 61,123 (JA 339-52)). On April 2, 2004, the Commission moved to dismiss the petition for review in No. 03-1292 for lack of jurisdiction, asserting that the challenged orders did not aggrieve Petitioners. On April 19, 2004, Petitioners responded that they were aggrieved by the April 25 and July 24, 2003 *Devon* orders, because the orders revised NEPOOL "market rules" to which Petitioners are subject. Opp. at 2. On April 27, 2004, based on that representation, FERC withdrew its motion to dismiss as to those two orders. Nonetheless, the Court's June 16, 2004 Order consolidating No. 03-1292 and No. 04-1062 referred FERC's motion to dismiss to the merits panel, and directed the parties to make their jurisdictional arguments on brief. On further review, and in accordance with the June 16, 2004 Order, FERC renews its request for dismissal of the petition in No. 03-1292 for lack of jurisdiction. *See also Liberty Mut. Ins. Co. v. Wetzel*, 424 U.S. 737, 740 (1976) ("[t]hough neither party has questioned the jurisdiction of the Court of Appeals to entertain the appeal, we are obligated to do so on our own motion if a question thereto exists"). As discussed *infra*, the *Devon* orders' revision of NEPOOL "market rules" (specifically, Market Rule 1) did not aggrieve Petitioners.

824d(e), on the grounds (a) that such agreements would discourage the entry of much-needed generation into the Connecticut market, and (b) that implementation of the "peaking-unit safe harbor" ("PUSH") bidding mechanism would provide the generators a reasonable opportunity to recover their fixed costs through their sales of electric power, pending the anticipated development of a more permanent bidding mechanism?

3. Assuming jurisdiction, did the *Devon* orders satisfy FPA § 206(a), 16 U.S.C. § 824e(a), when they revised Market Rule 1 of the New England Power Pool ("NEPOOL") tariff by substituting the PUSH bidding mechanism for an existing "CT proxy" bidding mechanism that had not provided generators a reasonable opportunity to recover their fixed costs?

4. Did the *Wallingford* orders reasonably reject the RMR cost-of-service agreement filed by Petitioners under FPA § 205(e) on the grounds (a) that such agreements would discourage the entry of much-needed generation into the Connecticut market, and (b) that implementation of the PUSH bidding mechanism would provide Petitioners a reasonable opportunity to recover their fixed costs through their sales of electric power, pending the anticipated development of a more permanent bidding mechanism?

PERTINENT STATUTES AND REGULATIONS

The statutes and regulations applicable to this case are set forth in an addendum to this brief.

STATEMENT OF THE CASE

I. Legal Framework

A. The Federal Power Act

The FPA grants the Commission jurisdiction over the transmission and wholesale sale of electric energy in interstate commerce. *See* 16 U.S.C. § 824(b)(1). Under that Act, public utilities must charge rates and engage in practices that are just, reasonable and not unduly discriminatory. 16 U.S.C. §§ 824d(a) & (b).

The FPA requires public utilities to file "schedules" showing all "rates and charges" for jurisdictional services, all "practices and regulations affecting such rates and charges," and all "contracts which in any manner affect or relate to such rates, charges . . . and services." 16 U.S.C. § 824d(c). The Act prohibits such utilities from making any change in such rates or services prior to giving the Commission and the public sixty days' notice, 16 U.S.C. § 824d(d), and prescribes the manner in which utilities provide such notice, and in which the justness and reasonableness of the proposed change is determined. 16 U.S.C. § 824d(e).

FPA § 206(a) provides that when the Commission, after a hearing, finds a previously approved tariff provision or rate to be unjust, unreasonable or unduly discriminatory, it must determine a prospective just and reasonable provision or rate and "fix the same by order." 16 U.S.C. § 824e(a). The proponent of the change has the burden of showing that the existing rate or tariff provision is unjust and unreasonable and that the new rate or tariff provision is just and reasonable. *See Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 184 (D.C. Cir. 1986).[3] Such changes may only be imposed prospectively. *See FPC v. Sierra Pac. Power Co.*, 350 U.S. 348, 353 (1956).

When using a "cost-of-service" methodology to set rates, the Commission sets an electric utility's unit rates by dividing its projected cost of service, expressed in dollars, by its customers' projected "demand," *i.e.*, power requirements, expressed in wattage. The utility's cost of service is the total revenue needed to cover the utility's operations and to attract investment; it includes depreciation expense and a just and reasonable return on its rate base (*i.e.*, on the investment it has made in its facilities).

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[3] *Sea Robin* interpreted Sections 4(e) and 5(a) of the Natural Gas Act ("NGA"), 15 U.S.C. §§ 717c(e) & 717d(a), provisions virtually identical to FPA §§ 205(e) and 206(a). The two provisions are properly interpreted consistently with one another. *Arkansas La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981) ("*Arkla*").

See generally Boston Edison Co. v. FERC, 885 F.2d 962, 964-65 (1st Cir. 1989) (Breyer, J.).

The Public Utilities Regulatory Policy Act authorizes the Commission to exempt public utilities from state laws that would otherwise prohibit the utilities from voluntarily coordinating their services. 16 U.S.C. § 824a-1. Agreements among public utilities to coordinate services are sometimes referred to "power pooling" agreements, and are subject to Commission regulation under the FPA. *See generally Central Iowa Power Coop. v. FERC*, 606 F.2d 1156 (D.C. Cir. 1979). Such agreements "promote reliable and economical operation of the interconnected electric network[.]" *Id.* at 1160 (footnote omitted).

B. Restructuring of the Electric Power Market

"Historically, electric utilities were vertically integrated, owning generation, transmission, and distribution facilities, and selling these services as a 'bundled' package to wholesale and retail customers in a limited geographical service area." *Public Util. Dist. No. 1 of Snohomish County, Wash. v. FERC*, 272 F.3d 607, 610 (D.C. Cir. 2001). In recent years, technological advances and legislative and regulatory initiatives have enabled new participants to enter into wholesale electricity markets, and have encouraged electric utilities to "unbundle" their services. This has led to an increasingly competitive market for the sale of electric energy and power. *See New York v. FERC*, 535 U.S. 1, 5-14 (2002) (describing developments).

As relevant here, FERC Order No. 888[4] directed each jurisdictional transmission-owning utility to unbundle its wholesale generation and transmission services, *New York*, 535 U.S. at 11, and directed utilities and power pools to file open-access transmission tariffs ("OATTs"), which generally provide transmission access on a non-discriminatory basis. *See* Order No. 888 at 31,727-28, 31,768-69. Order No. 888 also encouraged utilities providing operational control of regional, multi-system transmission grids to independent system operators ("ISOs"). *See id.* at 31,730-32.

Such grids subsequently emerged, operated by ISOs under an OATT. The ISOs, *inter alia*, act as middlemen between generators and customers, matching supply and demand, and dispatching power where needed. Eventually, the

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[4] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Servs. by Pub. Utils. & Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, FERC Stats. & Regs., Regs. Pmbls. ¶ 31,036 (1996), *clarified*, 76 FERC ¶ 61,009 & 76 FERC ¶ 61,347 (1997), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs., Regs. Pmbls. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248, *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part*, *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York*, *supra*.

Commission proposed that the grids submit "standard market designs" ("SMDs") that would govern the terms under which buyers and sellers of electric power would effectuate wholesale sales in a given region. *Remedying Undue Discrimination Through Open Access Transmission Serv. & Standard Elec. Market Design, Notice of Proposed Rulemaking*, 100 FERC ¶ 61,138 (2002). SMDs were to replace and bring uniformity to the disparate sets of regional rules governing such transactions, and thereby eliminate undue discrimination in the national marketplace.

C. Regulation of Power Sales in New England

ISO New England, Inc. ("ISO-NE") operates NEPOOL, which encompasses the New England power market. *See New England Power Pool*, 79 FERC ¶ 61,374 (1997), *order on reh'g*, 85 FERC ¶ 61,242 (1998). In this capacity, ISO-NE operates the region's principal transmission lines and regulates the region's sales of power. ISO-NE schedules power sales in a day-ahead market (in which the ISO matches offers to sell – referred to as "bids" – and requests to purchase power for the next day) and the real-time market (matching sales offers and purchase requests on an hour-by-hour basis). *See New England Power Pool*, 100 FERC ¶ 61,287 PP 5-8, *reh'g denied*, 101 FERC ¶ 61,344 (2002).[5]

[5] "P" denotes the paragraph number of the Commission order.

ISO-NE schedules sales of power based on economic dispatch, so that the lowest bids are dispatched first. *See New England Power Pool*, 85 FERC ¶ 61,379 at 62,459 (1998). This means that generating units that have the highest variable costs (and which can be expected to make the highest bids) are the least active. The ISO-NE operates a "single-price clear auction" under which the highest (and therefore last) bid accepted for a given area sets the "clearing price" for that area, so that every generator whose bid is accepted receives that price for its power, regardless of what the generator initially bid. *See New England Power Pool*, 100 FERC ¶ 61,287 P 63; *Wallingford*, 103 FERC ¶ 61,185 P 14.

Prior to 2000, there were no price caps on generator sales in the NEPOOL region. *NSTAR Servs. Co. v. New England Power Pool*, 92 FERC ¶ 61,065 (2000). During 2000, the Commission approved ISO-NE's proposed price caps of $1,000 per megawatt-hour ("MWh") for the NEPOOL region, with lower caps for more chronically constrained regions, called "Designated Congestion Areas" ("DCAs"). *Id.* at 61,209.

In September 2002, the Commission approved in part and modified in part an SMD submitted by ISO-NE and NEPOOL. *New England Power Pool*, 100 FERC ¶ 61,287. The SMD, which prescribed the terms under which generators could sell power, replaced NEPOOL's then existing market rules with new Market Rule 1. *Id.* P 3.

The ISO-NE SMD proposed new pricing for generators serving DCAs. *New England Power Pool*, 100 FERC ¶ 61,287 P 16. Here, "both the Commission's and NE-ISO's immediate concern is to protect customers from market power, while ensuring that generators required for reliability will remain economically viable[.]" *New England Power Pool*, 103 FERC ¶ 61,304 ¶ 18 (2003). In addition, the "longer term [pricing] solutions" contemplate facilitating "higher prices within DCAs" for the principal purpose of "incenting entry" by additional generators into these areas. *Id.*

To address those objectives, ISO-NE's proposal integrated three concepts. ISO-NE proposed "mitigation," or price reduction, through a "safe harbor bid cap" for generators during periods of constraint that was "based on the estimated price to recover the annual cost of a new combustible turbine unit (CT) for the region over the number of hours . . . the DCA is constrained." *Devon*, 103 FERC ¶ 61,082 P 3 n.3 (JA 238). This "CT proxy" mechanism acted as a price cap in DCAs. *See New England Power Pool*, 100 FERC ¶ 61,287 P 44 (safe harbor bid acts as a "bid cap whenever all available capacity in the area is needed to serve load reliability").

To soften the impact of mitigation on lower-cost generation in DCAs, the Commission modified the clearing price concept to allow the highest bid accepted in a

NEPOOL zone to set the price, called the "Locational Marginal Price" or "LMP," for all accepted bids within that zone. *New England Power Pool*, 100 FERC ¶ 61,287 P 63. The LMP mechanism was calculated to encourage the entry of new, more efficient generation units in DCAs. *See id.* P 71 (the implementation of LMP should provide "appropriate price signals" as to "the value of additional resources").

The Commission also softened the impact of mitigation by reaffirming ISO-NE's authority to negotiate cost-of-service agreements with certain, seldom-used units needed to assure system reliability.[6] The SMD permitted ISO-NE to designate such units as "RMR units," defined as "units which must be run" – *i.e.*, could be compelled by ISO-NE to run – "during certain periods to alleviate congestion" in transmission lines. *New England Power Pool*, 100 FERC ¶ 61,287 P 17. *See also Public Utils. Comm'n of Cal. v. FERC*, 254 F.3d 250, 252 (D.C. Cir. 2001) (explaining RMR service). ISO-NE could negotiate cost-of-service agreements with designated RMR units that could not recover their costs under the CT proxy mechanism. *New England Power Pool*, 100 FERC ¶ 61,287 P 18. ISO-NE filed a *pro forma* "RMR Cost-of-Service Agreement for units that would otherwise be shut down" and that were "required for system reliability." *Id.* P 19. The RMR cost-of-service agreement

[6] On February 14, 2002, the Commission interpreted NEPOOL Market Rule 17.3.2.2(b) to provide such authority. *Sithe New Boston, LLC*, 98 FERC ¶ 61,164 at 61,611, *reh'g denied*, 100 FERC ¶ 61,106 (2002).

contemplated monthly payments to each designated unit to recover its fixed costs, plus a reasonable return; revenues received by the unit for providing power would be deducted from the fixed payments. *See id.* P 47 & n.24. Generators had to file executed RMR agreements with the Commission for review under FPA § 205(e). *Id.* P 50.

The Commission indicated that ISO-NE's authority to enter into cost-of-service RMR agreements was limited. ISO-NE was to enter into such agreements covering only those units needed to assure reliability, and the agreements were to be effective only during the periods in which the units were needed to provide reliability. *New England Power Pool*, 101 FERC ¶ 61,344 P 33.

III. The Proceedings Below

Notwithstanding the expectation that RMR agreements would be used sparingly, ISO-NE "determined that absent any transmission improvements or new resources, largely *all* of the existing [generation] resources in Connecticut are needed for reliability[.]" *Devon*, 103 FERC ¶ 61,082 P 14 n.9 (JA 239) (emphasis added). This meant any generator in the state could be compelled to operate as an RMR unit, and, conversely, was eligible to apply for an RMR cost-of-service agreement.

A. *Devon Power LLC*

On February 26, 2003, four applicants ("*Devon* applicants")[7] filed four separate RMR cost-of-service agreements, negotiated with their affiliate, NRG Power Marketing Inc. ("NRG"), and ISO-NE, and covering generating units that ISO-NE had designated as RMR units. *Devon*, 103 FERC ¶ 61,082 PP 1, 7 (JA 237-38). The agreements covered 1,728 Megawatts ("MW"), including 40% of the capacity for the Southwest Connecticut ("SWCT") DCA. *Id.* PP 7, 13 (JA 238-39). Under the proposed agreements, the generators would offer to sell RMR power at a stipulated price, and to the extent the generators' sales of power did not recover their fixed costs, the generators were to receive monthly payments to make up the difference. *See, e.g.*, Cost-of-Service Agreement Between ISO-NE, NRG and Devon §§ 3.1, 3.3 (JA 174-76).

The *Devon* applicants represented that bids at the CT proxy level would not recover all their fixed costs because the CT proxy rates were designed to permit fixed-cost recovery for generating units that operated throughout periods of congestion, and the *Devon* applicants' units would run for substantially less time. *Devon*, 103 FERC ¶ 61,082 P 28 (JA 241). The *Devon* units were expected to run at an average of 8%

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[7] The applicants were Devon Power LLC ("Devon"), Middletown Power LLC, Montville Power LLC, Norwalk Power LLC and NRG Power Marketing Inc. *Devon*, 103 FERC ¶ 61,082 P 1 (JA 237).

rated capacity, *id.* n.16 (JA 241), which presumably would be lower than the rated capacity of a new combustible-turbine unit.

On March 12, 2003, the *Devon* applicants filed an emergency motion asking the Commission to grant limited approval of the agreements to permit applicants to recover necessary maintenance expenditures. *Devon*, 102 FERC ¶ 61,314 P 1 (2003) (JA 200). On March 25, 2003, the Commission granted the motion. *Id.*

However, the first challenged order in No. 03-1292, issued on April 25, 2003, rejected the other components of these RMR agreements on the ground that the stipulated bids in such agreements suppressed market prices, reduced the incentive for new generation to enter the market, and created pressure for the execution of cost-of-service agreements for even more RMR units. *Devon*, 103 FERC ¶ 61,082 P 29 (JA 241) ("April 25 *Devon* order"). Thus, the applicants were limited to recovering their maintenance costs through the proposed agreements. *Id.* P 32 (JA 242).

At the same time, the Commission, acting under FPA § 206(a), ordered ISO-NE to modify Market Rule 1 by replacing the CT proxy bid mechanism with the PUSH bid mechanism. *Devon*, 103 FERC ¶ 61,082 P 33 (JA 242). The latter was designed to give RMR generating units a reasonable opportunity to recover their costs through the market, *Devon*, 104 FERC ¶ 61,123 P 88 (JA 349), *i.e.*, through the prices the units received for their power. Under the PUSH mechanism, a generator that had operated at 10% or less of capacity during 2002 could make safe-harbor bids up to a level that included its units' variable-cost and fixed-cost components. *Devon*, 103 FERC ¶ 61,082 P 33 (JA 242). The fixed-cost component was calculated by dividing a unit's annual fixed costs (which included a 10% profit, called an "adder") by the number of MW hours that the unit supplied in 2002. *Id.* The Commission further provided that accepted PUSH bids could set LMP, *i.e.*, could serve as the sales price for all power sold in the DCA during that time period. *Id.* P 35 (JA 242). Finally, the Commission directed ISO-NE to "eliminate the current CT Proxy mechanism." *Id.* P 36 (JA 242). Because that mechanism was "designed to allow a new CT to recover its costs over all hours of congestion in a DCA[,]" peaking units "that produce energy in substantially fewer hours" were "not as likely to be able to recover all of their fixed costs" under that mechanism as under the newly instituted PUSH bids. *Id.* P 34 (JA 242). The Commission did not direct ISO-NE to modify any part of its tariff relating to negotiation of RMR agreements.

The second challenged order in No. 03-1292, issued July 24, 2003, denied rehearing, noting that the PUSH mechanism not intended to guarantee generators recovery of their costs, but rather to provide them "a reasonable opportunity to recover their costs" through their bids to sell RMR power. *Devon*, 104 FERC ¶ 61,123 P 28 (JA 342) ("July 24 *Devon* order").

B. *PPL Wallingford Energy LLC*

Petitioners have sold power at market-based rates in the SWCT DCA from five 45-MW natural-gas combustible turbines since February 2002. *Wallingford*, 103 FERC ¶ 61,185 P 2 (JA 246). As the units are "intended to run only at times of peak demand[,]" Br. at 6-7, the institution of price caps in the SWCT DCA made it more difficult for those units to recover costs.

On January 16, 2003, Petitioners filed a proposed RMR cost-of-service agreement covering four of the units that had an overall capacity of 180 MW and had operated at only 8% of capacity during 2002. *Wallingford*, 103 FERC ¶ 61,185 PP 2, 3 (JA 246-47). The proposed agreement contained terms similar to the RMR cost-of-service agreements in the *Devon* proceeding. *Compare id.* P 4 (JA 247) *with* Cost-of-Service Agreement between ISO-NE, NRG and Devon §§ 3.1, 3.3 (JA 174-76).

The first challenged order in No. 04-1062 rejected Petitioners' filing, citing the rationale articulated in the *Devon* orders. *Wallingford*, 103 FERC ¶ 61,185 P 3 (JA 246-47). The second challenged order in No. 04-1062 denied rehearing. *Wallingford*, 105 FERC ¶ 61,324 (2003) (JA 412-18).

The petitions for review followed.

SUMMARY OF ARGUMENT

I

The petition for review in No. 03-1292 should be dismissed for lack of jurisdiction because the *Devon* orders do not aggrieve Petitioners. FPA § 313(b) confers standing to seek judicial review of FERC action only on persons who are aggrieved as a result of that action. To satisfy this requirement, a petitioner must show the existence or the unavoidable threat of concrete, perceptible harm. The mere adoption of legal principles uncongenial to a petitioner, without more, does not meet that test.

Petitioners have not demonstrated that they were aggrieved by the *Devon* orders. As relevant here, those orders rejected RMR cost-of-service agreements to which Petitioners were not parties, announced that such agreements should be used only as a last resort, and modified ISO-NE's Market Rule 1 by implementing the PUSH bidding mechanism, which Petitioners acknowledge provides them a better opportunity to recover their costs through the bidding process than did the previous mechanism. Petitioners cannot demonstrate that any of these actions caused them injury, and therefore are not entitled to seek review of the orders.

II

Assuming jurisdiction, all the orders challenged in both petitions should be affirmed. In 2003, the Commission faced the imminent proliferation of RMR cost-of-service agreements throughout Connecticut. The Commission properly concluded that such a proliferation would not serve the competitive market because RMR cost-of-service agreements suppress bid prices and discourage the entry of new generation units. Thus, the Commission stated that such agreements should be utilized only as a last resort, while directing ISO-NE to raise bid ceilings in DCAs to give generating units, including seldom-used units, a reasonable opportunity to recover their fixed costs.

The PUSH bidding mechanism implemented by the Commission was reasonably calculated to provide such an opportunity. The mechanism contemplated seldom-used units offering energy at a price/MWh calculated by dividing their revenue requirements, including a reasonable return, by their 2002 production in MWh. Because those units are only used during periods of peak demand, a unit's 2002 MWh production constituted a reasonable estimate of its 2003 MWh production. In addition, FERC ruled that PUSH prices could set LMP for the relevant region. This meant that all generating units in that region could receive the highest accepted PUSH price for their power. The PUSH bidding mechanism, which was to remain in effect only until ISO-NE developed a more permanent mechanism, was a reasonable stop-gap, designed to block the spread of bid-suppressing RMR cost-of-service agreements and otherwise encourage the movement of new generation to Connecticut.

FERC's rejection of Petitioners' RMR cost-of-service agreement was also reasonable. Petitioners did not demonstrate any unique aspect of their RMR agreement, or of their operations, that warranted acceptance of their agreement or otherwise precluded their use of PUSH bids. Moreover, if the highest allowable PUSH bids in their DCA were accepted, Petitioners stood to recover more than double their highest allowable PUSH bid.

The Commission provided an equally sound rationale under FPA § 206(a) for revising NEPOOL's Market Rule 1. The existing CT proxy bidding mechanism was unjust and unreasonable in that it did not provide seldom-used generating units a reasonable opportunity to recover their costs, whereas the PUSH bidding mechanism was just and reasonable in that it provided those units just such an opportunity. In addition, it is not disputed that the PUSH mechanism provided seldom-used units a better opportunity in this regard than did the CT proxy.

ARGUMENT

I. THE PETITION FOR REVIEW IN NO. 03-1292 SHOULD BE DISMISSED FOR LACK OF JURISDICTION.

The petition for review in No. 03-1292 should be dismissed for lack of jurisdiction. FPA § 313(b) confers standing to seek judicial review of FERC action only on a "party to a proceeding . . . aggrieved by an order issued by the Commission in such proceeding." 16 U.S.C. § 825*l*(b). The *Devon* orders do not aggrieve Petitioners.

A petitioner is "aggrieved" within the meaning of FPA § 313(b) only if, as a result of a FERC order, that petitioner "has sustained 'injury in fact' to an interest 'arguably within the zone of interests to be protected or regulated' by the [Commission] under the Act." *Northwestern Pub. Serv. Co. v. FPC*, 520 F.2d 454, 458 (D.C. Cir. 1975). To satisfy the "injury-in-fact" prong of the test, a petitioner must show facts "sufficient to prove the existence of a concrete, perceptible harm of a real, non-speculative nature[.]" *North Carolina Utils. Comm'n v. FERC*, 653 F.2d 655, 662 (D.C. Cir. 1981) (citation and internal quotation omitted). Moreover, "'petitioner's aggrievement must be present and immediate, or at least must be demonstrably a looming unavoidable threat.'" *Northwestern*, 520 F.2d at 458 n.6 (quoting *Cincinnati Gas & Elec. Co. v. FPC*, 246 F.2d 688, 694 (D.C. Cir. 1957)).

The petitioner has the burden of demonstrating such injury. *Friends of Keeseville, Inc. v. FERC*, 859 F.2d 230, 235 (D.C. Cir. 1985) ("'It is not this court's job to ferret out or even to speculate as to possible impacts of possible outcomes of existing lawsuits upon future litigation; it is the petitioner's responsibility to show the specifics of the injury alleged.'" (quoting *North Carolina*, 653 F.2d at 663)). Thus, failure to demonstrate concrete, imminent harm requires dismissal.

Aggrievement does not arise because a FERC ruling deprives parties "of a legal theory that they would like to use" in another case. *Transwestern Pipeline Co. v. FERC*, 747 F.2d 781, 785 n.5 (D.C. Cir. 1984) (Scalia, J.). On the contrary, "the adoption of uncongenial legal principles that do not have immediate adverse effect or even immediate prospect of adverse effect is not enough to create a 'person aggrieved.'" *Id.*[8]

Petitioners have not demonstrated they are aggrieved by the *Devon* orders. The orders did three things that are relevant here: (1) they rejected the RMR agreements filed by the *Devon* applicants; (2) they announced that because a proliferation of RMR

[8] Other than *Friends of Keeseville*, the foregoing cases interpreted NGA § 19(b), 15 U.S.C. § 717r(b), a provision virtually identical to FPA § 313(b). The two provisions are properly interpreted consistently with one another. *Arkla*, 453 U.S. at 577 n.7.

agreements would not serve competitive markets, particularly DCAs, such agreements should be used only as a last resort; and (3) they modified NEPOOL's Market Rule 1 to substitute the PUSH bidding mechanism for the CT proxy mechanism. *See* 103 FERC ¶ 61,082 PP 31-36 (JA 241-42). Petitioners have not demonstrated, and cannot demonstrate, that they have sustained any cognizable injury as a result of those actions. The Commission's rejection of the *Devon* applicants' RMR cost-of-service agreements did not injure Petitioners in any way. Petitioners were not parties to those agreements.

Nor were Petitioners injured by the *Devon* orders' announcement that RMR cost-of-service agreements would only be approved "as a last resort." That announcement, at most, slightly modified existing policy regarding approval of such agreements. Though Petitioners may have found the modification "uncongenial" to their interests, the announcement did not cause Petitioners any concrete, immediate harm, *see Transwestern*, 747 F.2d at 785 n.5, or pose a "looming, unavoidable threat." *Northwestern*, 520 F.2d 458 n.6. Indeed, though Petitioners challenge the policy, they also assert that it did not require rejection of their proposed RMR cost-of-service agreement. *See* Br. at 49-51, discussed *infra* at 37-38.

Finally, the Commission's substitution of the PUSH mechanism for the CT proxy mechanism did not injure Petitioners because the PUSH mechanism provides them a better opportunity to recover their units' costs than did the CT proxy. *See* 103 FERC ¶ 61,082 P 34 JA 242). Petitioners do not dispute the PUSH mechanism's superiority to the CT proxy on brief, and acknowledged that FERC's "PUSH bidding mechanism" was "an improvement over the proxy CT DCA safe harbor approach" on rehearing. JA 254.

II. ASSUMING JURISDICTION, ALL THE ORDERS SHOULD BE AFFIRMED.

A. Standard of Review

The role of judicial review is only to ascertain if the agency "has met the minimum standards set forth in the statute." *U.S. Postal Serv. v. Gregory*, 534 U.S. 1 (2001). A court reviews FERC orders under the "arbitrary and capricious" standard set out in the Administrative Procedure Act at 5 U.S.C. § 706(2)(A). *Sithe/Independence Power Partners v. FERC*, 165 F.3d 944, 948 (D.C. Cir. 1999). To satisfy that standard, the Commission must "demonstrate that it has made a reasonable decision based on substantial evidence in the record and the path of its reasoning must be clear." *Id.* (citations and internal quotations omitted). Like other administrative agencies, the Commission may depart from past policies, as long as it provides a reasonable explanation for its actions. *See, e.g.*, *Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

B. The Commission's Actions Were Reasonable and Proper.

1. The Commission Properly Rejected the RMR Cost-of-Service Agreements.

The Commission was facing a proliferation of RMR cost-of-service agreements throughout the State of Connecticut, and especially in the SWCT DCA. Approval of the *Devon* RMR cost-of-service agreements would have removed 1,728 MW of capacity from the market, which translated to 40% of the capacity in the SWCT DCA. *Devon*, 103 FERC ¶ 61,082 PP 7, 13 (JA 238-39). Approval of Petitioners' RMR cost-of-service agreement would have removed another 180 MW from the SWCT DCA market. *Wallingford*, 103 FERC ¶ 61,185 PP 1, 3 (JA 246-47). Given ISO-NE's determination that "largely all of the existing resources in Connecticut are needed for reliability[,]" *Devon*, 103 FERC ¶ 61,082 P 27 (JA 241), other Connecticut generators could be expected to file proposed RMR cost-of-service agreements similar to those filed by the *Devon* applicants and by Petitioners.

The Commission found that "the proliferation of these agreements" was "not in the best interest of the competitive market[.]" *Devon*, 103 FERC ¶ 61,082 P 31 (JA

241). Specifically, "RMR contracts suppress market-clearing prices, increase uplift payments, and make it difficult for new generators to profitably enter the market. . . . because under current market rules, generators operating under a cost-of-service RMR contract . . . offer power under a Stipulated Bid Cost" – essentially a bid based on some, but not all, of the generators' costs – and "are then entitled" to collect their remaining fixed costs under "a monthly fixed cost payment[.]" *Id.* P 29 (JA 241). The stipulated bids suppress "market clearing prices" thereby producing "lower revenues" for "new entrants" and other, existing generators that must rely entirely on their sales of power for revenue. Growing use of RMR cost-of-service agreements thus increases the likelihood "that additional units will also require RMR agreements to remain profitable." *Id.* To counteract this trend, the Commission concluded, "RMR agreements should be a last resort[.]" *Id.* P 31 (JA 241).

At the same time, the Commission implemented the PUSH bidding mechanism to give "selected high cost but seldom run units in DCAs[,]" *Devon*, 103 FERC ¶ 61,082 P 32 (JA 242), "a reasonable opportunity to recover their fixed and variable costs" through the bidding process. *Devon*, 104 FERC ¶ 61,123 P 2 (JA 339). The Commission had two sound reasons for concluding that the PUSH mechanism would provide seldom-used units such an opportunity.

First, the fixed-cost component of a unit's PUSH bid was calculated by dividing the unit's fixed-cost requirement (including a 10% return) by its hours of operation during 2002. *See Devon*, 103 FERC ¶ 61,082 P 33 (JA 242). Because such units are used only during peak periods of peak generation, the hours of use could be expected to remain constant from year to year.[9]

Second, as part of this new approach, "the energy bids of peaking units" would be "eligible to determine LMP" in a DCA. *Devon*, 103 FERC ¶ 61,082 P 35 (JA 242). In other words, an accepted peaking-unit bid would set the price for all other sellers in the DCA and allow them "to receive a high market price and recover fixed costs." *Id.* Thus, to the extent the LMP was set by older, more expensive generators, seldom-used units could recover revenues that appreciably exceeded their fixed costs despite operating fewer hours during 2003 than during 2002. *Cf. Devon*, 104 FERC ¶ 61,123 P88 (JA 349) (referring to "equal risk that eligible units may under-recover or over-recover their costs"). For example, whereas Petitioners' highest allowable PUSH bid was $418/MWh, other units in the SWCT DCA could make bids of $1000/MWh. *See* Exhibit JC-4 (JA 335). If the latter bids set LMP, Petitioners' units (as "price takers") would receive more than double their allowable PUSH bids for their sales of power.

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[9] Petitioners have not disputed the ability of eligible units to recover their variable

Moreover, allowing PUSH bids to set the LMP would "encourage entry by new generators[,]" into DCAs. *Devon*, 103 FERC ¶ 61,082 P 35 (JA 242). This is because new entrants would likely have more efficient, lower-cost generators than those making PUSH bids, yet the new entrants would receive the same price as the PUSH bidders during the periods in which PUSH bids set LMP. Thus, unlike the threatened proliferation of RMR cost-of-service agreements, implementation of the PUSH mechanism would encourage the movement of new generation to Connecticut.

The PUSH bidding mechanism was scheduled to "remain in effect" only until ISO-NE made a filing that placed "into effect certain changes to the market prior to the 2004 summer peak season[.]" *Devon*, 103 FERC ¶ 61,082 P 32 (JA 242). The mechanism was a reasonable stop-gap, designed to block the spread of bid-suppressing RMR agreements until a more permanent mechanism was developed.

2. The Commission Properly Revised Market Rule 1 Under FPA § 206(a).

The Commission provided a sound rationale, under FPA § 206(a), for revising NEPOOL's Market Rule 1. The April 25 *Devon* Order's discussion of "the extensive disruption to the market caused by RMR contracts" showed "that Market Rule 1, in

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costs through PUSH bids.

view of the measures proposed by ISO-NE, created an unjust and unreasonable result, requiring a revision in the rule to solve these problems." *Devon*, 104 FERC ¶ 61,123 P 33 (JA 343) (citing *Devon*, 103 FERC ¶ 61,082 PP 28-31 (JA 241-42)). Accordingly, "rather than focusing on and using stand-alone RMR agreements" to compensate RMR units, ISO-NE was to "incorporate the effect of those agreements into a market-type mechanism." *Devon*, 103 FERC ¶ 61,082 P 29 (JA 241).

The existing "market-type mechanism," the CT proxy, was inadequate to the task. That mechanism was "designed to allow a new CT to recover its fixed costs over all hours of congestion in a DCA." *Devon*, 103 FERC ¶ 61,082 P 34 (JA 242). In other words, the CT proxy rate was calculated by dividing the estimated annual fixed costs of a new CT by the estimated annual hours of congestion in the DCA. While a generating unit that ran throughout those congested periods (and that incurred fixed costs approximating those of a new CT) could expect to recover its costs, peaking units "that produce[d] energy in substantially fewer hours, such as the [*Devon*] Applicants' units," were "not likely to be able to recover all of their fixed costs[.]" *Id*. The CT proxy rate's inability to recover the fixed costs of peaking units made it unjust and unreasonable. Accordingly, the Commission properly directed ISO-NE to eliminate this mechanism from Market Rule 1. *See id.* P 36 (JA 242).

The PUSH bidding mechanism, which used each unit's 2002 hours of operation to calculate its rate, was just and reasonable because it provided peaking units "a reasonable opportunity to recover their fixed and variable costs" through a market mechanism. *Devon*, 104 FERC ¶ 61,123 P 2 (JA 339). Moreover, allowing PUSH bids to set the LMP would "encourage entry by new generators" to a much greater extent than the CT proxy mechanism, and unlike the bid-suppressing RMR cost-of-service agreements. *Id.*

C. Petitioners' Arguments to the Contrary Are Unavailing.

The only issue properly before the Court in No. 04-1062 is whether the Commission properly rejected Petitioners' RMR cost-of-service agreement. If the Court should find that it has jurisdiction over the petition in No. 03-1292, then the Court must also consider whether the *Devon* orders properly: (1) rejected the *Devon* applicants' proposed RMR cost-of-service agreements; and (2) revised Market Rule 1 of the NEPOOL tariff by replacing the CT proxy bidding mechanism with the PUSH bidding mechanism. Petitioners' arguments are discussed as they bear on the foregoing issues.

1. The Commission's Rejection of Petitioners' RMR Cost-of-Service Agreement Was Reasonable.

a. The Commission Properly Concluded that the PUSH Bidding Mechanism Provided Petitioners a Reasonable Opportunity To Recover Their Fixed Costs.

Petitioners argue that they were denied a reasonable opportunity to recover their fixed costs because the PUSH bidding mechanism's use of a unit's 2002 MWh production assured that the allowable bid would be too small to recover fixed costs during 2003. Br. at 34-37. In support, Petitioners offer a June 12, 2003 affidavit by a consultant, Joseph Cavicchi. *Id.* at 36 (citing Cavicchi Affidavit (JA 313-21)). Mr. Cavicchi predicted that in the second half of 2003: (1) the production of "many of" Petitioners' units would "be lower" because of "increased gas prices"; and (2) PUSH units would sustain "reduced run times" because the units would "face competition in many hours from other resources . . . able to offer their production at price levels . . . lower than the PUSH bid levels[.]" Cavicchi Affidavit P 6 (JA 315-16). While Mr. Cavicchi predicts lower run times for Petitioners' units, Petitioners also make the unsupported allegation that their units were unlikely to receive the PUSH price for all of the MWh they supplied even if their 2003 MWh production equaled that of 2002. Br. at 38.

Although Petitioners criticized the use of 2002 production levels, they did not offer an alternative means of estimating 2003 production in either the *Devon* or the *Wallingford* proceeding. The Commission found the 2002 levels were "the most useful and readily available estimate of going forward production levels," and observed that Petitioners had "not shown how a more accurate estimate could be developed and implemented." 104 FERC ¶ 61,123 P 28 (JA 342).[10]

The Commission also explained that the PUSH bidding mechanism was designed to do no more than "allow seldom-run units an opportunity to recover costs through the market." *Devon*, 104 FERC ¶ 61,123 P 88 (JA 349). There was "equal risk that eligible units" might "under-recover or over-recover their costs" as they were "free to bid anywhere below the PUSH level." *Id.* "[T]he PUSH mechanism" did not "guarantee" that units would "recover all of their costs," but rather gave "them a reasonable opportunity to do so." *Id.* Petitioners have failed to demonstrate that the Commission's conclusion that the PUSH mechanism would accomplish its intended goals was unreasonable.

First, Petitioners' claim that higher PUSH bid prices (exacerbated by higher variable costs for gas) would result in lower production and run times for Petitioners' units ignores that those units were intended to run only during periods of peak demand, Br. at 6-7, when they were needed regardless of price. *See Wallingford*, 103 FERC ¶ 61,185 P 2 (JA 246) (units ran at only 8% of capacity). Petitioners did not point to any new entrants that would provide the alleged increase in competition in

[10] Petitioners' failure even to suggest an alternative PUSH methodology indicates that

2003. Thus, it was reasonable for the Commission to conclude that Petitioners' units would be needed as (in)frequently in 2003 as they had been in 2002.

Moreover, neither Petitioners nor Mr. Cavicchi note the potential additional revenues made available to Petitioners' units by making PUSH bids eligible to set LMP during periods of peak demand. Petitioners would receive that LMP for their power despite the LMP's being well in excess of Petitioners' PUSH ceiling. *See Devon*, 103 FERC ¶ 61,082 P 35 (JA 242) ("energy bids of peaking units" would be "eligible to determine LMP" so that when a peaking unit was called, all sellers would "be able to receive a high market price and recover fixed costs"); *Wallingford*, 103 FERC ¶ 61,185 P 14 (JA 248) (Petitioners "may receive a price that exceeds [their] offer when a higher cost bid is also accepted"). Indeed, according to Mr. Cavicchi's data, the highest PUSH bid any of Petitioners' units were allowed to offer in 2003 was $418/MWh, whereas four other units in the SWCT DCA were authorized to offer PUSH bids of $1,000/MWh. *See* Exhibit JC-4 (JA 335). To the extent the latter bids set the LMP, Petitioners could receive revenues substantially in excess of their costs.

Petitioners further claim that a report prepared at the Commission's direction and filed by ISO-NE on December 4, 2003 – eighteen days before the issuance of the rehearing order in the *Wallingford* proceeding – supports their position. Br. at 38-39.

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what they really are seeking is a guaranteed recovery of costs.

According to Petitioners, the report "concluded that PUSH bidders, such as [Petitioners'] units, would likely recover an average of 35 percent of their costs under the PUSH system." *Id.*

The Court lacks jurisdiction to consider this report in reviewing the challenged orders, as Petitioners never raised it on rehearing before the Commission. The FPA precludes the Court from considering objections that a petitioner fails to make on rehearing absent good cause for the failure. 16 U.S.C. § 825*l*(b). The courts have strictly adhered to that requirement. *See, e.g., Domtar Me. Corp. v. FERC,* 347 F.3d 304, 313 (D.C. Cir. 2003) (even FERC's concession that two arguments are closely related does not justify a petitioner's raising one on rehearing and the other on judicial review). *See also Panhandle Eastern Pipe Line Co. v. FPC*, 324 U.S. 635, 645 (1945) (petitioner precluded from raising objection on judicial review that was not raised on rehearing, despite petitioner's having raised the objection earlier in the administrative proceeding); *ASARCO, Inc. v. FERC*, 777 F.2d 764, 773-74 (D.C. Cir. 1985) (petitioner precluded from raising objection on judicial review that petitioner failed to raise on rehearing, even though other parties raised the same argument on rehearing).

In addition, the ISO-NE report was filed on December 4, 2003, well after the issuance of the last *Devon* order on July 24, 2003. *See* 104 FERC ¶ 61,123 (JA 339-52). The Commission's actions must be assessed based on the evidence before it when it makes its decision. *See James Madison, Ltd. v. Ludwig*, 82 F.3d 1085, 1095 (D.C. Cir. 1996) (in reviewing agency action, courts normally consider only those facts "that were 'before the agency at the time the decision was made'") (quoting *Environmental Defense Fund v. Costle*, 657 F.2d 275, 284 (D.C. Cir. 1981)).

The fact that the ISO-NE Report had not been written when Petitioners filed their request for rehearing in the *Wallingford* proceeding does not provide them "good cause" for their failure to raise the report to the Commission. Because the report was issued on December 4, 2003, eighteen days prior to the date of the last *Wallingford* order, December 22, 2003, Petitioners could have brought the report to the Commission's attention in the context of this proceeding, by supplemental filing or otherwise. Absent such effort, Petitioners lack good cause for not raising the report, and their omission deprives the Court of jurisdiction to consider the report on judicial review.

In any event, the ISO-NE Report provides little support for Petitioners' position. The Report, which is based on a three-month period in the summer of 2003 and says nothing about Petitioners' specific units, concludes that the "PUSH offer mechanism" provided "greater cost recovery than could have occurred under the previous mitigation rules." "A Review of Peaking Unit Safe Harbor (PUSH) Implementation and Results" ("PUSH Review") at 1 (JA 361). Notwithstanding its recommendation that the PUSH mechanism be replaced by a more permanent bidding mechanism (as the Commission had required), the Report did not suggest more frequent use of RMR cost-of-service agreements, *see id.* at 34-35 (JA 394-95), the course recommended by Petitioners. Thus, the report supports FERC's approach.

b. The Commission Used Sound Assumptions in Directing Implementation of the PUSH Mechanism.

Petitioners also contend that implementation of the PUSH mechanism was based on the flawed assumption that Petitioners would operate and receive PUSH bids for the same number of hours during 2003 that the units operated during 2002. Br. at 37-38. It is Petitioners' characterization of the Commission's reasoning that is flawed.

As maximum PUSH bids had to be set prior to bidding, the Commission used 2002 production levels, because they were "the most useful and readily available estimate of going forward production levels," and Petitioners had "not shown how a more accurate estimate could be developed and implemented." *Devon*, 104 FERC ¶ 61,123 P 28 (JA 342). Petitioners still have not provided an alternative estimate.

Petitioners also ignore the effect of FERC's allowing PUSH bids to set the LMP. During periods in which units with higher price ceilings than Petitioners' units set LMP, Petitioners will receive the LMP for their power even though that price exceeds their maximum allowable PUSH bid. *See Devon*, 103 FERC ¶ 61,082 P 35

(JA 242); *Wallingford*, 103 FERC ¶ 61,185 P 14 (JA 248). Thus, under PUSH, a unit was as likely to over-recover its fixed costs as to under-recover them. *Devon*, 104 FERC ¶ 61,123 P 88 (JA 349).

c. The Commission Reasonably Found that the PUSH Mechanism Would Encourage New Generation in Connecticut.

Petitioners assert that the PUSH mechanism will not achieve FERC's goal of encouraging new generation. Petitioners argue that the PUSH mechanism does not allow eligible generators a reasonable opportunity to recover their fixed and variable costs and that the mechanism does not allow such generators to receive "scarcity" prices. Br. at 41-45. Petitioners conveniently ignore that the compensation vehicle they prefer, RMR cost-of-service agreements, do not allow scarcity pricing.

The Commission reasoned that permitting "energy bids of peaking units . . . to determine LMP" would "encourage entry by new generators." *Devon*, 103 FERC ¶ 61,082 P 35 (JA 242). This is because whenever higher-priced generation sets the LMP, a lower-priced generator will be able to collect revenues for its power well in excess of its costs. *See Wallingford*, 103 FERC ¶ 61,185 P 14 (JA 248).

The Commission's determination was reasonable. Making PUSH bids eligible to set the LMP provided most existing peaking-unit generators the prospect of receiving energy prices well beyond even the PUSH bids their units were allowed to make. *See* Exhibit JC-4 (JA 335). As new entrants could reasonably be expected to provide units that were more efficient and operated at lower costs than existing peaking units, the Commission reasonably concluded that its policy would spur new entry.

d. The Commission Was not Required To Make a Particularized Finding Regarding Petitioners' Units.

Petitioners argue that the Commission simply applied the *Devon* reasoning to their RMR cost-of-service agreement without sufficient consideration of their particular situation. Br. at 49-52. Nothing required the Commission to make the particularized findings that Petitioners describe.

As discussed *supra*, the *Devon* orders took steps to prevent a proliferation of RMR cost-of-service agreements on the grounds that: (1) such agreements contemplate generators making stipulated bids that depress market prices and thereby discourage entry of new generation (103 FERC ¶ 61,082 P 29 (JA 241)); and (2) PUSH bids would give generators a reasonable opportunity to recover their costs, if not the guarantee provided by RMR agreements. 104 FERC ¶ 61,123 P 88 (JA 349). The *Wallingford* orders applied this reasoning to Petitioners' agreement. 103 FERC ¶ 61,185 P 13 (JA 248).

By submitting for approval an unexecuted *pro forma* RMR agreement, which FERC had already considered and approved, *Wallingford*, 103 FERC ¶ 61,185 P 4 (JA 247), Petitioners indicated that they did not view their case as unique. Nor have Petitioners pointed to any other factors unique to them. *See id.* P 2 (JA 246) (Petitioners claim they are having "difficulty" recovering their costs). Thus, Petitioners have failed to show that any aspect of their situation dictated that they be treated differently from the *Devon* applicants.

Instead, Petitioners raised generalized objections to the efficacy of the PUSH bidding mechanism. Such generalized statements are inadequate to show that the mechanism was any less applicable to Petitioners' units than to other units.[11]

e. The Commission Satisfactorily Explained Its Reasons for Rejecting Petitioners' RMR Cost-of-Service Agreement.

Petitioners further claim that in rejecting their RMR cost-of-service agreement, the Commission departed without explanation from its policy of permitting such agreements. Br. at 52-54. This argument fails on two counts.

[11] In a different section of the brief, Petitioners suggest that their situation was different from that in *Devon* because their generator capacity was only 180 MW rather than the *Devon* applicants' 1,728 MW. Br. at 35 n.19. Petitioners do not elaborate on this point, and, in any event, their failure to raise it on rehearing, *see* JA 293-95, deprives the Court of jurisdiction to consider it now. *See Domtar*, 347 F.3d 313.

First, the Commission's rejection of the instant RMR cost-of-service agreements responded to a threatened proliferation of such agreements, *Devon*, 103 FERC ¶ 61,082 PP 13, 31 (JA 239, 241-42), in the face of a Commission directive that they be used sparingly. *See New England Power Pool*, 101 FERC ¶ 61,344 P 33 (limiting RMR cost-of-service agreements to units needed for reliability and limiting the terms of such agreements to periods of such need). Moreover, the *Devon* orders did not disturb any part of Market Rule 1 relating to RMR agreements or preclude submission of such agreements in the future, as long as such submissions were made as "a last resort." *See* 103 FERC ¶ 61,082 P 31 (JA 241).

This was a reasonable response to a new situation. ISO-NE had declared virtually *all* generators in Connecticut to be RMR, *Devon*, 103 FERC ¶ 61,082 P 14 n.9 (JA 239), thus creating a situation in which virtually *every* generating unit in the state had the duties and entitlements of RMR units. This situation inevitably magnified the negative consequences of approving RMR cost-of-service agreements because such agreements became more likely to depress the clearing price as they increased in number. *Id.* P 29 (JA 241). Neither *Sithe New Boston, LLC*, 98 FERC ¶

61,164, nor *ISO New England, Inc.*, 101 FERC ¶ 61,341 (2002), cited by Petitioners, presented such a situation.[12]

Petitioners also suggest that the Commission's subsequent acceptance of certain RMR cost-of-service agreements demonstrates that FERC acted arbitrarily here. Br. at 25-30 (citing *ISO New England, Inc.*, 105 FERC ¶ 61,263 PP 11, 20-21 (2003); *Devon*, 106 FERC ¶ 61,264 PP 4, 12, 18 (2004); *Exelon New Boston, LLC*, 106 FERC ¶ 61,191 P 1 (2004); *Devon*, 107 FERC ¶ 61,002 P 10 (2004); *Devon*, 107 FERC ¶ 61,240 PP 1, 4, 35, 36, 72 (2004)).

The situations presented by *ISO New England* and *Wallingford* differed materially.[13] In *ISO New England*, the Commission conditionally approved a one-year extension of an RMR cost-of-service agreement that pre-dated the *Devon* orders and that applied only to units that were *not* eligible to make PUSH bids. *See* 105 FERC ¶ 61,263 PP 1, 2, 17. In those circumstances, the Commission reasoned, "the only

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[12] ISO-NE does not appear to have brought its designation of Connecticut generation units as RMR to the Commission's attention until the *Devon* applicants filed their application. *See* 103 FERC ¶ 61,082 P 27 & n.14 (JA 241).

[13] All of the orders except *ISO New England* were issued *after* the issuance of the challenged orders, and, therefore, are not properly before the Court. *See Union Pac. Fuels, Inc. v. FERC*, 129 F.3d 157, 164 (D.C. Cir. 1997) (Commission's actions after issuing the challenged orders "play no role" in the Court's "determination of the orders' legality"). Moreover, the Court lacks jurisdiction to consider the alleged discrepancies between all of the orders, including *ISO New England*, and the instant

avenue open to ISO-NE to ensure that these units remain in operation for reliability in southwest Connecticut is to offer an RMR agreement." *Id.* P 22. Moreover, the covered units, which Devon had previously sought to deactivate, were needed for reliability only until the new "Milford Station" generating unit began commercial operation. *See id.* P 2. The contrast is striking: Devon sought approval of a one-year extension of an RMR cost-of-service agreement applicable only to soon-to-be-deactivated units that were ineligible for PUSH bidding, whereas Petitioners are seeking approval of an RMR cost-of-service agreement for new units that are eligible for PUSH bidding.

The other decisions cited by Petitioners are similarly inapposite. For example, in *Devon*, 106 FERC ¶ 61,264 PP 16, 18, the Commission conditionally accepted RMR cost-of-service agreements for a limited term only because the units were "older and less efficient, with higher marginal costs, and generally provide[d] only operating reserves." The Commission explained that the "PUSH mechanism" and "other recent changes in the New England market" had "achieved the Commission's goal of providing cost recovery through the market for many generating units required to operate for reliability purposes." *Id.* P 18. Indeed, the "[a]pplicants acknowledge[d] this in their filing," noting that they "had not sought RMR contracts" for other

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orders because Petitioners did not raise the purported discrepancies on rehearing. *See* specified units because they were "achieving sufficient revenues through market mechanisms." *Id.* (footnote omitted).

2. Petitioners' Contentions Regarding FPA § 206(a) Fail.

Petitioners argue that the Commission failed to satisfy its burden under FPA § 206(a) in replacing RMR cost-of-service agreements with the PUSH mechanism. *See* Br. at 46-49. Petitioners claim, without elaboration, that the Commission's "criticisms of RMR agreements" – the "old rate" in Petitioners' view – "fell far short of demonstrating they were unjust, unreasonable, unduly discriminatory or preferential." *Id.* at 47. In addition, Petitioners contend, the Commission failed to establish that the PUSH mechanism, the "new rate," was just and reasonable. *Id.* at 47-49; *see id.* at 48 (relying on *id.* at 34-37 to establish that the PUSH mechanism did not provide their units a reasonable opportunity to recover their "full fixed costs").

Petitioners misapprehend the revision to Market Rule 1, none of which related to RMR agreements. Even Petitioners admit "in adopting the PUSH mechanism, the Commission did not prohibit RMR agreements." *See* Br. at 50. Rather, the revision to Market Rule 1 replaced the CT proxy mechanism with the PUSH mechanism. *Devon*,

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Domtar, 347 F.3d at 313.

103 FERC ¶ 61,082 PP 33-36 (JA 242). Thus, the "old rate" for FPA § 206(a) purposes was the CT proxy mechanism, not FERC's policy regarding acceptance of RMR cost-of-service agreements.

a. The Arguments Apply Solely to Orders that the Court Lacks Jurisdiction To Review.

Petitioners' FPA § 206(a) challenges apply only to the *Devon* orders because those were the orders that revised Market Rule 1. *Devon*, 103 FERC ¶ 61,082 PP 33, 36 (JA 242). As the Court lacks jurisdiction to review the *Devon* orders, it necessarily lacks jurisdiction to consider Petitioners' challenges to the Commission's actions under FPA § 206(a).

In addition, Petitioners' challenge is based solely on arguments (*see* Pet. Br. at 48, citing *id.* at 34-37) that rely on the Cavicchi Affidavit, which Petitioners did not mention in their request for rehearing in the *Devon* proceeding. *See* JA 251-70. Petitioners' omission deprives the Court of jurisdiction to consider the affidavit in connection with the *Devon* orders. *See, e.g., Domtar,* 347 F.3d 313.

b. The Arguments Fail on the Merits.

Assuming the Court has jurisdiction to review the *Devon* orders, Petitioners' arguments regarding FPA § 206(a) fail because the revisions to Market Rule 1 met the elements of FPA § 206(a). The first step was met by the April 25 *Devon* Order's discussion of "the extensive disruption to the market caused by RMR contracts[,]" which showed "that Market Rule 1, in view of the measures proposed by ISO-NE, created an unjust and unreasonable result, requiring a revision in the rule to solve these problems." *Devon*, 104 FERC ¶ 61,123 P 33 (JA 343) (citing *Devon*, 103 FERC ¶ 61,082 PP 28-31 (JA 241-42)). The disruption threatened by a proliferation of such agreements forced a harder look at, and exposed the unjustness and unreasonableness of, the existing CT proxy bidding mechanism, which did not provide seldom-used units in DCAs a reasonable opportunity to recover their fixed costs. *See Devon*, 103 FERC ¶ 61,082 P 34, 36 (JA 242); 104 FERC ¶ 61,123 P 33 (JA 343). The second step was met by finding that the PUSH bidding mechanism, as implemented, was reasonably calculated to provide such an opportunity, and was, therefore, just and reasonable. *See Devon*, 103 FERC ¶ 61,082 PP 33-36 (JA 242).

3. No Hearing Was Required in the Instant Proceedings.

Finally, Petitioners claim the Commission failed to comply with the requirements of FPA § 206(a) by not setting for hearing the decision to substitute its PUSH bidding mechanism for Petitioners' RMR agreement. Br. at 54-57. However, as has been discussed, the Commission's action under FPA § 206(a) was confined to revising Market Rule 1 by substituting the PUSH bidding mechanism for the CT proxy mechanism; moreover, the Commission took this action in the *Devon* proceeding, where Petitioners' RMR cost-of-service agreement was not at issue. *See* 103 FERC ¶ 61,082 P 33 (JA 242).

Petitioners failed to object to the absence of an evidentiary hearing in their request for rehearing in the *Devon* proceeding. *See* JA 251-70. Accordingly, the Court is without jurisdiction to consider this objection on judicial review. *Domtar*, 347 F.3d 312.

In any event, the Commission was not required to conduct a hearing in this case prior to acting under FPA §§ 205 or 206 because it was able to resolve the disputed issues on the written record before it. *See, e.g., Cajun Elec. Power Coop. v. FERC*, 28 F.3d 173, 177 (D.C. Cir. 1994); *Moreau v. FERC*, 982 F.2d 556, 568 (D.C. Cir. 1993). Petitioners do not set out any material factual disputes that needed to be resolved through an evidentiary hearing. Accordingly, the Commission properly resolved the legal and policy issues based on the filings of the parties. *See Devon*, 103 FERC ¶ 61,082 PP 9-26 (JA 238-40) (summarizing parties' positions).

CONCLUSION

For the foregoing reasons, the petition for review of the *Devon* orders should be dismissed, and the *Wallingford* orders should be affirmed.

Respectfully submitted,

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