118 FERC ¶ 61, 205
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Richard Blumenthal, Attorney General for the State of Connecticut, the Connecticut Office of Consumer Counsel, the Connecticut Municipal Electric Energy Cooperative and the Connecticut Industrial Energy Consumers — Docket No. EL05-150-001

v.

ISO New England, Inc.

ORDER DENYING REHEARING

(Issued March 15, 2007)

1. On November 9, 2006, Richard Blumenthal, Attorney General for the State of Connecticut (CT AG), filed a request for rehearing of the Commission's October 11, 2006 Order in this docket.[1] The October 11 Order denied the complaint filed by the CT AG and other Complainants[2] against ISO New England, Inc. (ISO-NE). The complaint addressed compensation for electric generation facilities in Connecticut. It sought amendment of ISO-NE's tariff, Market Rule 1, to require that all electric generation facilities in Connecticut be compensated on a cost-of-service basis through Reliability

[1] *Richard Blumenthal, Attorney General for the State of Connecticut, et al. v. ISO New England, Inc.*, 117 FERC ¶ 61,038 (2006) (October 11 Order).

[2] Complainants, aside from the CT AG, also included the Connecticut Office of Consumer Counsel (CT OCC), the Connecticut Municipal Energy Electric Cooperative (CMEEC), and the Connecticut Industrial Energy Consumers (CT IEC).

Must Run (RMR) agreements until the Commission made a determination that Connecticut's electricity markets were competitive and producing revenues consistent with the just and reasonable standard of the Federal Power Act (FPA).

2. The CT AG's request for rehearing states that in the October 11 Order, which denied the original complaint without a hearing, the Commission acted arbitrarily and capriciously and failed to engage in reasoned decision-making. In this order, the Commission will deny the CT AG's request for rehearing, as discussed below.

I. Background

A. Development of the New England Capacity Market

3. As a means of ensuring reliability, for many years ISO-NE has imposed an installed capacity (ICAP) requirement on load-serving entities, requiring them to procure specified amounts of capacity based on their peak loads, plus a reserve margin. In 1998, ISO-NE began operating a bid-based market for ICAP;[3] then, in 2000, as part of the region's development of wholesale power markets and market-based rates, the Commission first began to identify flaws in the ICAP (or capacity) market. ISO-NE filed a proposal to eliminate the existing capacity mechanism, but the Commission rejected that proposal, reasoning that ISO-NE should first propose an alternative mechanism to meet the reliability function served by the ICAP requirement.[4] The Commission did allow ISO-NE to replace the ICAP auction mechanism with an administratively-determined ICAP deficiency charge, due to the auction's potential for producing inflated market prices for capacity.[5]

4. In 2002, the Commission approved a new standard market design for New England (Market Rule 1), which established locational marginal pricing for the energy market.[6] In its Market Rule 1 Order, the Commission identified the lack of a locational element in the capacity market as a significant flaw, stating its belief that "location is an

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[3] *See New England Power Pool*, 83 FERC ¶ 61,045 at 61,263 (1998).

[4] *See ISO New England, Inc.*, 91 FERC ¶ 61,311 (2000), *order on reh'g*, 95 FERC ¶ 61,384 (2001).

[5] *Id.*

[6] *New England Power Pool and ISO New England, Inc.*, 100 FERC ¶ 61, 287 (Market Rule 1 Order), *order on reh'g*, 101 FERC ¶ 61, 344 (2002).

important aspect of ensuring optimal investment in resources."[7] The Commission thus directed that a locational capacity mechanism be developed, but noted that the industry did not hold a uniform view on either the optimal method to ensure that capacity resources were being most efficiently located, or the most efficient and workable method of compensation for these capacity resources.[8]

5. Market Rule 1 did provide some mechanisms intended to help generators needed for reliability recover sufficient costs to stay in the market. Generators in designated congestion areas (*i.e*., formally identified chronically constrained regions) were permitted to bid into the energy market up to a "safe harbor" level without triggering mitigation.[9] Market Rule 1 also provided that where a unit determined by ISO-NE to be needed for reliability was not being adequately compensated by the market, it was permitted to seek a cost-of-service RMR agreement as a means of ensuring that the unit would remain available for reliability. Though the Commission approved the use of RMR contracts as a part of Market Rule 1, it has often stated that they are meant to be used as a last resort and that, in a competitive market where cost recovery is not guaranteed, generators should be guaranteed only the *opportunity* to recover their costs.[10]

6. In 2003, the Commission examined the ability of New England's markets to adequately compensate generators needed for reliability and the use of RMR agreements in constrained areas of the region, particularly southwest Connecticut. The Commission rejected several proposed RMR agreements, expressing concern that these agreements would distort prices in the competitive capacity market.[11] In the energy market, the

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[7] Market Rule 1 Order, 100 FERC ¶ 61, 287, at P 101.

[8] *Id*.

[9] The safe harbor bid cap was based on a pre-specified combustion turbine proxy price (CT Proxy), representing the cost of operating a hypothetical peaking unit.

[10] *See, e.g., Bridgeport Energy, LLC*, 112 FERC ¶ 61,077, at P 39 (2005) (*Bridgeport*).

[11] *See, e.g. Devon Power LLC, et al.*, 102 FERC ¶ 61,314 (*Devon I*) *and Devon Power LLC, et al.*, 103 FERC ¶ 61,082 (*Devon II), reh'g granted in part and denied in part*, 104 FERC ¶ 61,123 (2003) (*Devon III*); *PPL Wallingford Energy LLC*, 103 FERC ¶ 61,085, *reh'g granted in part and denied in part*, 105 FERC ¶ 61, 324 (2003), *vacated and remanded sub nom. PPL Wallingford Energy LLC v. FERC*, 419 F.3d 1194 (D.C. Cir. 2005).

Commission replaced the original safe harbor bid cap with revised bidding rules – called Peaking Unit Safe Harbor (PUSH) bidding – as an interim measure to give low-capacity factor generating units operating in designated congestion areas the opportunity to recover their costs through the market.[12] Additionally, the Commission directed ISO-NE to develop and file by March 1, 2004 a permanent locational mechanism in the ICAP market so that capacity located in designated congestion areas would be appropriately compensated for reliability.[13]

7. In 2004, ISO-NE filed a proposed locational installed capacity (LICAP) mechanism, as directed. While the Commission found the proposal conceptually sound, it determined that additional revisions were necessary before the locational mechanism could be implemented. Accordingly, the Commission set the matter for hearing.

8. Meanwhile, the Commission became aware that PUSH bidding was not functioning as anticipated:[14] PUSH units (located, by definition, in designated congestion areas) were performing poorly under the PUSH bidding rules.[15] Thus, in 2004 and 2005, the Commission began to accept RMR agreements, but conditioned them to terminate on the day a location-based capacity or deliverability requirement was implemented pursuant to the Commission's directive to ISO-NE.[16] The Commission reasoned that accepting RMR agreements for a limited term was appropriate, given that the units covered by the

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[12] *Devon II*, 103 FERC ¶ 61,082, at P 33-36. The PUSH bidding regime allowed a low-capacity factor generator – defined as a generating unit with a capacity factor of ten percent or less during 2002 – to bid up to a level equal to its fixed costs pro-rated over its hours of operation during 2002, without the application of market power mitigation rules.

[13] *Id*. at P 37. This directive is consistent with the Commission's position in the Market Rule 1 Order regarding the importance of a locational element for the capacity market.

[14] *See A Review of Peaking Unit Safe Harbor (PUSH) Implementation and Results*, filed December 4, 2003 in Docket No. ER03-563-025 (PUSH Report).

[15] On January 12, 2007, the Commission conditionally approved the elimination of PUSH bidding, explaining that ISO-NE has developed market mechanisms to provide more effective price signals and ensure adequate resources to support reliability. *See ISO New England, Inc. and New England Power Pool*, 118 FERC ¶ 61,018 (2007) (PUSH Order).

[16] *Devon Power LLC, et al.*, 109 FERC ¶ 61,154, at P 16-20 (2004) (*Devon IV*).

contracts were aging, low-capacity factor units that were performing poorly under PUSH bidding rules.[17] The Commission has also approved limited-term RMR agreements for newer baseload facilities needed for reliability that demonstrated an inability to earn sufficient revenues to keep generation units available to provide reliability services. In other cases, the Commission has conditionally approved and set for hearing the issue of the need for certain proposed RMR agreements.

9. On June 16, 2006, the Commission approved the Forward Capacity Market (FCM), adopted by parties in the settlement to the LICAP proceeding as an alternative to the LICAP mechanism.[18] The FCM establishes annual auctions for capacity and its first commitment period is scheduled to begin June 1, 2010. In FCM auctions, capacity will be sold on a per-megawatt of deliverable capacity basis. From 2006 through June 1, 2010, until capacity can be sold and procured via auction, generators providing installed capacity will receive transition payments. The FCM settlement provides that RMR agreements will terminate at the beginning of the first commitment period of the FCM.

B. <u>Original Complaint</u>

10. On September 12, 2005, Complainants, including the CT AG, filed a complaint requesting that the Commission amend Market Rule 1 to require that all electric generation facilities in Connecticut be compensated on a cost-of-service basis, through RMR agreements, until the Commission made the determination that electricity markets in Connecticut were competitive and that re-introduction of market-based rates would be consistent with the just and reasonable standard of the FPA. The complaint asserted that because consumers in Connecticut were forced to pay the higher of either cost-of-service rates under RMR agreements or market-based rates for electricity, the system was unjust and unreasonable and in violation of the FPA.

C. <u>October 11 Order</u>

11. In the October 11 Order, the Commission denied Complainants' request to amend Market Rule 1. The Commission stated that Complainants failed to meet their burden of proof under section 206 to establish (1) that the provisions of Market Rule 1 regarding the compensation of generating facilities needed for reliability in Connecticut were unjust

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[17] *Id*.

[18] *Devon Power LLC*, 115 FERC ¶ 61,340 (FCM Settlement Order), *order on reh'g*, 117 FERC ¶ 61,133 (2006). Two of the four parties to the original complaint, CMEEC and the CT OCC, are parties to the FCM settlement.

and unreasonable; and (2) that Complainants' proposed alternative -- to put all generating units in Connecticut under RMR contracts -- was just and reasonable.

II. Request for Rehearing

12. The CT AG requests rehearing of the October 11 Order, arguing that the Commission acted arbitrarily and capriciously and failed to engage in reasoned decision-making by denying the complaint without a hearing. The CT AG states that the Commission's failed "hybrid" system in Connecticut, made up of both regulated and market elements, deprives consumers of the benefits they should expect (*i.e.*, lower prices) if either a cost-based or market-based regime were to exist in isolation.[19] The CT AG states that the hybrid system has allowed high-cost generators to opt out of the market in favor of guaranteed cost-of-service compensation (through RMR contracts) far above what those generators would receive in a competitive region-wide market, while lower variable cost units operate as if there were an open, competitive market, thereby collecting "market" rates set by non-market participant high-cost generators.

13. The CT AG also contends that another class of units, those using PUSH bidding to recover their costs, are allowed to continue submitting energy bids that far exceed what would be expected in a truly competitive market. The CT AG states that units relying on PUSH have the opportunity to increase congestion costs in constrained regions and to collect uplift charges for out-of-merit operation when they are needed for local area reliability, even though other less expensive alternatives are available in the region-wide energy market. In addition, the CT AG avers that the Commission has allowed some generation owners to place certain units under cost-of-service compensation while keeping neighboring sister units for participation in the market, resulting in both regulated and unregulated generating plants, owned by the same corporate entity, operating side-by-side.

14. Arguing that the failed hybrid system in place does not reflect a working market-based system, the CT AG states that Connecticut's consumers, rather than investors, bear the risk of operating losses. The reason for this, the CT AG states, is that any generator that cannot turn a "huge profit in this make-believe market"[20] can instead opt for fully regulated returns and profit levels. Moreover, the CT AG explains, the ability of certain

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[19] The CT AG notes that Connecticut's 2006 rates are over 70 percent higher than they were in 2003 and that the state is poised for substantial rate hikes in January 2007.

[20] CT AG November 9, 2006 Reh'g Request at 5.

generators in Connecticut to maintain "supra-competitive profits" is the hallmark of market failure.[21]

A. Failure to Order a Hearing

15. The CT AG argues that the Commission erred in not setting the complaint for hearing.[22] The CT AG states that the Complainants provided a "verification of the data supporting the estimates of windfall profits for the nuclear and coal units located in Connecticut" and that no other party "challeng[ed] the accuracy of that data."[23] The CT AG states that, by not ordering a hearing, the Commission failed to "review the cumulative impact of its failed market policies in determining whether the Connecticut wholesale electric markets remain workably competitive."[24]

Commission Determination

16. The Commission denies rehearing for several reasons. First, the complaint did not request a hearing.[25] Instead, it sought summary revisions to Market Rule 1.[26] Second, the complaint did not merit a hearing in any event. The CT AG argues that it provided "verified" evidence of "windfall profits." But this "verified" evidence, even assuming it was accurate, was not material to the CT AG's request for relief. As indicated, the CT AG sought summary revisions to Market Rule 1 to place every generator in Connecticut under RMR cost-based rates. This generic relief was premised on the assertion that a "hybrid" system (whereby certain generators receive market rates and others receive

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[21] *Id.*, citing *Tejas Power Corp. v. FERC*, 908 F.2d 998 (D.C. Cir. 1990).

[22] CT AG November 9, 2005 Reh'g Request at 6.

[23] *Id.* at 7-8.

[24] *Id.* at 9.

[25] See "Requested Relief," Complaint at 33-36.

[26] Complainants' only procedural request was that "[t]he Commission should open a proceeding within one year of the completion of the currently scheduled transmission projects in Connecticut to review the market structure in Connecticut and to determine whether market-based compensation is capable of being squared with the Federal Power Act." *Id.* at 35-36. The Commission notes that, as discussed infra at paragraph 20, the ISO-NE files quarterly and annual market reports with the Commission that, *inter alia*, assess the competitiveness of its markets.

RMR cost-based rates) is inherently unjust and unreasonable. We discuss and reject this contention below, but the relevant point here is that the contention does not turn on facts concerning any particular generator or market price. Indeed, the complaint went so far to allege that, even if only a few RMR units remain after implementation of the FCM, the market would still be unjust and unreasonable because it would retain its "hybrid" status.[27]

17. Finally, not every factual dispute (even assuming there was a material one) requires a trial-type hearing. The use of a paper hearing rather than a trial-type evidentiary hearing has been addressed in numerous cases.[28] A trial-type hearing is required when, for example, it is necessary to determine the credibility of witnesses,[29] but it is well settled that the Commission may determine disputed facts in a paper hearing, as it did here. The CT AG is therefore simply wrong in contending that "the Commission declined to conduct *any* hearing in this matter."[30] The Commission

[27] Complaint at 10.

[28] *E.g.*, *Public Service Company of Indiana*, 49 FERC ¶ 61,346 (1989), *order on reh'g*, 50 FERC ¶ 61,186, *opinion issued*, Opinion 349, 51 FERC ¶ 61,367, *order on reh'g*, Opinion 349-A, 52 FERC ¶ 61,260, *clarified*, 53 FERC ¶ 61,131 (1990), *dismissed*, *Northern Indiana Public Service Company v. FERC*, 954 F.2d 736 (D.C. Cir. 1992). As the Commission noted in Opinion No. 349, 51 FERC ¶ 61,367, at 62,218-19 and n.67, while the FPA and case law require that the Commission provide the parties with a meaningful opportunity for a hearing, the Commission is required to reach decisions on the basis of an oral, trial-type evidentiary record only if the material facts in dispute cannot be resolved on the basis of the written record, *i.e.*, where written submissions do not provide an adequate basis for resolving disputes about material facts.

[29] *See, e.g.*, *Iroquois Gas Transmission System, L.P*, 54 FERC ¶ 61,103 at 61,346-347 (1991). In addition, certain types of discovery rights, such as the taking of depositions, are more suitable for trial-type evidentiary hearings. *ISO New England, Inc.*, 116 F.E.R.C. ¶ 61,025, *citing, e.g.*, *Sound Energy Solutions*, 107 FERC ¶ 61,263, at P 78 (2004), *reh'g denied*, 114 FERC ¶ 61,058, at P 47 (2006); *Transcontinental Gas Pipe Line Corporation*, 84 FERC ¶ 61,160, at 61,870 (1998), *reh'g denied*, 87 FERC ¶ 61,136 (1999); *Pine Needle LNG Company, LLC*, 77 FERC ¶ 61,229, at 61,915-16 (1996), *reh'g denied*, 78 FERC ¶ 61,241 (1997).

[30] CT AG November 9, 2005, Reh'g Request at 8 (emphasis added).

conducted a hearing -- a paper hearing -- and in that hearing, considered all the arguments presented by the CT AG, as well as the other submissions in the case.[31]

B. Failure to Address Legal Arguments

18. The CT AG argues that the October 11 Order failed to provide any response or analysis that addressed Complainants' legal arguments. The CT AG argues that "the Commission made no reference, analysis or indeed any attempt to address the clearly defined obligations recognized in *Farmers Union* and [related precedents]."[32] The CT AG states that such failure is, in itself, arbitrary and capricious within the meaning of the Administrative Procedure Act (APA), 5 U.S.C. § 706. Under the "arbitrary and capricious" standard of the APA, the Commission must consider relevant data and articulate a rational connection between the facts found and the choices made, and must respond meaningfully to the arguments raised before it.[33] Accordingly, the CT AG avers, the Commission's failure to address or respond to the *Farmers Union* line of cases[34] represents an example of the Commission's consistent failure to comply with its affirmative legal obligations to ensure markets are workably competitive. The CT AG asserts that the Commission is obligated to make affirmative fact-based findings that the markets are workably competitive before it can rely on those markets to produce rates that are just and reasonable in the absence of cost-of-service regulation.[35]

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[31] It is well established that the Commission has broad discretion in deciding how best to organize and manage its proceedings. *See e.g.*, *Domtar Me. Corp. v. FERC*, 347 F.3d 304, 314 (D.C. Cir. 2003); *Michigan Public Power Agency v. FERC*, 963 F.2d 1574, 1579 (D.C. Cir. 1992).

[32] CT AG November 9, 2005, Reh'g Request at 9.

[33] *Id.* at 10, citing *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004, 1008 (D.C. Cir. 2005).

[34] The *Farmers Union* line of cases cite by the CT AG includes: *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486 (D.C. Cir. 1984) (*Farmers Union*), *cert. den. sub nom. Williams Pipeline Co. v. Farmers Union Cent. Exch., Inc.*, 469 U.S. 1034 (1984); *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004) (*Lockyer v. FERC*); *Tejas Power Corp. v. FERC*, 908 F.2d 998 (D.C. Cir. 1990); *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 871 (D.C. Cir 1993); and *La. Energy & Power Auth. v. FERC*, 141 F.3d 364, 365 (D.C. Cir. 1998).

[35] CT AG Reh'g Request at 7, citing *Lockyer*, 383 F.3d 1006; *see also id.* at 9.

Commission Determination

19. The Commission denies rehearing on this issue. The Commission did not ignore the relevant precedents. It is well settled that the Commission may authorize market-based rates if it finds that the seller requesting such authority cannot exercise market power.[36] In addition, and consistent with *Lockyer*, the Commission must engage in continuing oversight of markets for which market-based rates have been granted.[37]

20. Each of these prerequisites are satisfied for the New England markets at issue here. In 1998, when the Commission approved New England Power Pool's request to establish market-based rates in ISO-NE administered markets, the Commission made, *ex ante*, a fact-based finding that there was an absence of market power.[38] In addition, the Commission established procedures for ongoing oversight of the markets, including reporting requirements for ISO-NE and a requirement that ISO-NE monitor and assess the competitiveness of the markets it administered and release reports publicly and to regulators, including the Commission.[39] To satisfy this requirement, as part of its market monitoring function and in compliance with Appendix A, section 11.2.2 of section III of

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[36] *I.e.*, the Commission must determine that the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission, and cannot erect other barriers to entry. *See, e.g.*, *Lockyer*, 383 F. 3d at 1012-13, *La. Energy & Power Auth.*, 141 F.3d at 365; *Heartland Energy Servs., Inc.*, 68 FERC ¶ 61,223, at 62,060 (1994); *Louisville Gas & Elec. Co.*, 62 FERC ¶ 61,016, at 61,143-44 (1993).

[37] *Lockyer*, 383 F.3d 1006.

[38] *See New England Power Pool*, 85 FERC ¶ 61,379, at 62,477-78 (1998) (NEPOOL Order) (finding, in addition, that there was potential for sellers to have market power inside transmission-constrained areas, and directing mitigation measures to apply to any seller meeting the criteria outlined in NEPOOL's proposal for market power in a transmission-constrained area), *order on reh'g*, 95 FERC ¶ 61,074 (2001); *see also Vermont Electric Coop., Inc.*, 108 FERC ¶ 61,223, at PP 19-20 (2004) (finding that wholesale sellers must individually demonstrate that they should be authorized to sell at market-based rates by providing support to satisfy the Commission's four-part market-based rate analysis), *order on reh'g*, 110 FERC ¶ 61,232.

[39] *Id.*

Market Rule 1, ISO-NE files quarterly and annual market reports with the Commission that, *inter alia*, assess the competitiveness of its markets.[40]

21. In *Lockyer*, the court held that, where post-approval reporting requirements are imposed in support of market-based rate authorization, the Commission must properly enforce those reporting requirements.[41] The Commission's ongoing review of this market, including the aforementioned market reports and input from the independent market monitor, satisfies this requirement. Moreover, as the October 11 Order notes, Complainants did not offer any specific evidence of generator withholding or any other demonstration of market power to support their claim that the New England markets were not competitive. Nor did Complainants offer evidence that the Commission was failing to enforce reporting requirements that would reveal anti-competitive market behavior. The CT AG's request for rehearing does not provide any such evidence.

22. In addition, the CT AG appears to argue that, even if it does not contest our findings that individual sellers lack market power and our reporting and monitoring requirements are adequate, a "hybrid" system of cost- and market-based rates is inherently unjust and unreasonable. This argument has no merit. As indicated, the Commission may authorize market-based rates for sellers that lack or have adequately mitigated market power. The fact that *other* sellers in the same market may be approved for RMR cost-based rates is irrelevant to that question. As we have stated previously, RMR contracts are only approved after (1) a generator is found to be needed for reliability; and (2) out-of-market financial arrangements are necessary to ensure that the unit remains available.[42] Here these transitional contracts are necessary due to the lack of transmission infrastructure in Connecticut and (pre-FCM) insufficient capacity revenues. As generators under RMR contract are required to offer all of their capacity into the day-ahead and real-time energy markets at their marginal costs; their simultaneous presence in the market actually serves to lower LMPs.[43] Moreover, we note that any revenues that exceed an RMR unit's annual fixed revenue requirement (*i.e.*, transition payments under

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[40] *See* http://www.iso-ne.com/markets/mkt_anlys_rpts/index.html.

[41] *Lockyer*, 383 F. 3d 1006.

[42] "[T]he Commission has stated on several occasions [that] we prefer not to authorize 'out-of-market' RMR payments because they distort market clearing prices in a way that understates the value of resources necessary to reliably serve load." October 11 Order, 117 FERC ¶ 61,038, at P 58.

[43] *Id.* at P 68, 77.

FCM) are credited against these fixed RMR payments. For generators operating under market-based rates, such as the coal and nuclear units targeted in the complaint, bids that exceed specified conduct and impact thresholds may be mitigated to reference levels that reflect the units' estimated marginal cost.[44]

23. Finally, we also reject the rehearing request for all the reasons stated in our October 11 Order. In that order, we addressed in detail why the Complainants' attacks on RMR contracts, PUSH bidding and market-based rates had no merit.[45]

C. <u>Objections to the PUSH Report and PUSH Bidding</u>

24. The CT AG contends that the October 11 Order relies on incorrect or outdated factual premises, thereby undermining the Commission's legal and policy conclusions. Specifically, the CT AG identifies the 2003 PUSH Report[46] as an outdated document the Commission used in the October 11 Order to support its endorsement of "the current mix of market-based rates and mélange of *ad hoc* regulatory fixes."[47] The CT AG contends that circumstances have changed significantly since the period analyzed in the PUSH Report, including increases in load, dramatic changes in the fuel market, and the implementation of Commission-approved initiatives that provide additional revenue streams to generators. The CT AG lists changes to the New England markets that have been implemented since the PUSH Report: (1) adoption of a scarcity pricing mechanism in 2003 that allows the energy price cap to be exceeded in the real-time market during reserve shortage conditions; (2) adoption of a cold weather event procedure allowing generator bids to exceed the price cap; (3) RMR agreements approved by the Commission since 2003; and, (4) adoption of a locational forward reserve market (LFRM).

25. The CT AG also objects to the fact that NRG Energy, Inc.'s (NRG) Norwalk Harbor units are allowed to bid under the PUSH regime (due to their location in a constrained region),[48] while NRG has opted to put the vast majority of its Connecticut

[44] *Id*. at P 74.

[45] October 11 Order, 117 FERC ¶ 61,038, at PP 59-81.

[46] *See supra* note 14.

[47] CT AG Reh'g Request at 11.

[48] *See supra* note 12 for an explanation of PUSH bidding. The CT AG contends that if a generating unit's capacity factor exceeds its 2002 level in subsequent years, there is a high probability that the generator is over-recovering its regulated cost of service.

generation units under RMR contracts. The CT AG submits that Norwalk Harbor's operation reflects the exercise of unrestrained market power coupled with gaming of the Commission-approved ISO-NE rules for RMR contracts. The CT AG finds "seriously infirm" the Commission conclusion in the October 11 Order that increased revenues paid to the Norwalk Harbor units reflect compensation for scarcity value and are not the result of market power.[49]

26. The CT AG avers that Norwalk Harbor's nearly 100 percent market share within the Norwalk-Stamford load pocket should serve as a predictor that Norwalk Harbor bid its output at its authorized PUSH bid levels. If Norwalk Harbor did bid at these levels (which the CT AG admits that it cannot confirm), then, the CT AG contends, Norwalk Harbor effectively recovered twice its regulated cost of service, by doubling its capacity factor between 2002 and 2005. The CT AG argues that the bidding flexibility allowed by the PUSH regime permits a generating unit to increase profits beyond the just and reasonable standard authorized by the FPA. The CT AG states that the PUSH regime is particularly pernicious because a generation owner like NRG can selectively resort to RMR contracts for certain generating units, while keeping Norwalk Harbor in the "market" where, with its sizeable market share in a load pocket, it can realize excessive returns when measured by traditional cost-of-service.

Commission Determination

27. The Commission denies rehearing. The October 11 Order responded in detail to each allegation in the complaint regarding the PUSH mechanism.[50] The CT AG simply repeats arguments already addressed in the October 11 Order. Nothing in the rehearing request has persuaded us to alter those findings. As we found in the October 11, Order, the Norwalk Harbor units are the only large generation units providing reliability services in the Norwalk-Stamford load pocket, a location where these services are necessary; such units are subject to the same market power mitigation as other generators; the CT AG has not offered any specific evidence of withholding or any other demonstration of market power;[51] and there are no market rules in place to prevent construction of a competing generation facility.[52] Further, since the variable cost and fixed cost components of PUSH

[49] CT AG Reh'g Request at 12.

[50] October 11 Order, 117 FERC ¶ 61,038, at PP 59-75.

[51] The original complaint also did not offer any such evidence.

[52] *Id.* at P 63.

bids are specifically approved by the Commission for each PUSH unit, such bids do not allow the units to obtain prices far above what would be expected in a competitive market.[53] In sum, the Commission has no evidence that Norwalk Harbor revenues are improper, or unjust and unreasonable, or that they are operating contrary to the intent of the PUSH mechanism. Finally, we note, as we did in the October 11 Order, that nothing in our order "prevent[s] parties from challenging under section 206 the need for any generator in the market to retain PUSH bidding as a cost recovery mechanism."[54]

28. Finally, we note the transitional nature of the PUSH mechanism. In January 2007, the Commission conditionally approved ISO-NE and NEPOOL's joint filing to eliminate PUSH bidding, finding that PUSH bidding had not worked as anticipated and was no longer necessary.[55] In light of PUSH's impending elimination, the CT AG's concerns about generators that are using PUSH bidding to recover their costs (such as NRG) will soon be moot. However, the Commission does anticipate that NRG and any other generators that were relying on PUSH bidding to recover their costs will likely seek RMR agreements.[56] Should the Commission approve any additional RMR agreements as a result of the termination of PUSH, the Commission reiterates its position in the October 11 Order that, "to the extent that any party feels that an RMR agreement is no longer necessary (especially in light of transition payments under the FCM Settlement Agreement), that party is free to file for relief with the Commission under section 206."[57]

29. As for the CT AG's claim that NRG has been exercising unrestrained market power by using PUSH bidding while gaming the ISO-NE rules for RMR contracts -- by operating its Norwalk Harbor units under PUSH and other units under RMR contracts --

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[53] *Id.* at P 61.

[54] *Id.* at P 64.

[55] *ISO New England, Inc. and New England Power Pool*, 118 FERC ¶ 61,018, at P 46 (2007). In their transmittal letter requesting that PUSH be eliminated, ISO-NE and NEPOOL stated that PUSH had proven ineffective in achieving its intended goals of helping high cost, seldom-run units recover their fixed costs and of producing signals for investment through higher LMPs. This filing borrowed conclusions from the PUSH Report. *See* ISO-NE and NEPOOL November 14, 2006 Transmittal Letter, Docket No. ER07-219-000, at 5-6.

[56] *See* PUSH Order, 118 FERC ¶ 61,018, at P 48.

[57] October 11 Order, 117 FERC ¶ 61,038, at P 61.

the Commission already addressed this "cherry-picking" argument in the *PSEG Power Connecticut, LLC* proceeding and in the October 11 Order.[58] Our analysis from that proceeding applies to the CT AG's argument raised here and the CT AG offers no arguments that persuade the Commission to revisit its conclusions.

C. Short Term and Long Term Rates

30. The CT AG argues that the October 11 Order is arbitrary and capricious and otherwise inconsistent with the law in that it sanctions rates than are not just and reasonable in the "short-term" – which the CT AG claims could span decades[59] – in the hope that rates will moderate to just and reasonable levels in the "long-term." As evidence of the Commission's acknowledgement that the hybrid market is not working to provide the lowest reasonable prices in the near term, the CT AG quotes the following Commission statements from the October 11 Order:

> "While it may be true that the [Complainants'] proposal might benefit Connecticut ratepayers on a short term basis, such measures defeat the purpose of single price auctions and competitive markets, the intent of which are to establish just and reasonable rates over the long term that reflect the marginal cost of competitive generation in this market."[60]

> "When market-based rates exceed cost-based rates, it is not market failure but rather a signal for the construction of new generation and/or transmission, as well as the implementation of demand-side solutions. Over time, addition of these new resources will drive the marginal cost to serve the load, and thus LMPs, lower."[61]

The CT AG declares this reasoning, particularly the latter quote from the October 11 Order, to be circular and without merit and that, taken to its logical extreme, the Commission could support any market rate structure, no matter how uncompetitive and without any factual record or evidentiary hearing, solely on the

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[58] *Id.* at P 88, citing *PSEG Power Connecticut, LLC*, 110 FERC ¶ 61,020, at 33, *order on reh'g*, 110 FERC ¶ 61,441, *order denying reh'g*, 113 FERC ¶ 61,210 (2005).

[59] The CT AG asserts that it is undisputed that the "short-term" will last for at least ten to twenty years, and possibly much longer.

[60] October 11 Order, 117 FERC ¶ 61,038, at P 83.

[61] *Id.* at P 85.

hope that some "market" would eventually develop and deliver just and reasonable rates.

31. The CT AG states that the Commission's primary charge is to protect consumers against exploitation.[62] Further, the CT AG contends that the Commission is justifying near-term failure to provide reasonable rates with the argument that the market structure may work in the future -- after many, many low variable cost nuclear and clean coal plants are constructed throughout the New England region, enough to displace natural gas generators as marginal units.[63] But, the CT AG avers, the Commission has a responsibility under the FPA to ensure that rates are just and reasonable in the short and long term and it is arbitrary and capricious to force ratepayers to pay rates that are higher than just and reasonable for the decades that must be endured before the market can respond to "appropriate price signals."

Commission Determination

32. The Commission denies rehearing. The CT AG's argument is a classic straw man. It is premised on the assumption that we held that unjust and unreasonable prices may be acceptable in the short-run if they can be replaced by just and reasonable prices over the long turn. The October 11 Order makes no such a finding. Rather, we held that "[w]hen market-based rates exceed cost-based rates, it is not market failure but rather a signal for the construction of new generation and/or transmission, as well as the implementation of demand-side solutions."[64] We also held that "[a]s system conditions in Connecticut have grown tighter in recent years, combined with the increase in fuel price for marginal units, it is not surprising to see higher LMP prices. During such periods, the most efficient units may earn more than a cost of service rate."[65] We also held that "[t]he fact that low variable cost coal and nuclear baseload units are earning inframarginal revenues does not speak to the competitiveness of this market. These revenues provide incentives for

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[62] CT AG Reh'g Request at 8, citing *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 610 (1944).

[63] The CT AG derives this conclusion from October 11 Order paragraphs 79, 81, and 85. The CT AG posits that without a hearing, the Commission has no evidentiary basis to believe that such massive construction is even possible in Connecticut and New England, and if so, over what time horizon.

[64] October 11 Order, 117 FERC ¶ 61,038, at P 85.

[65] *Id.* at P 79.

existing generators to reduce their marginal costs and improve overall efficiency and for new, low cost generation to locate in congested areas."[66] In other words, just because market-based rates exceed cost-based rates during conditions of scarcity does not mean that such market-based rates become unjust or unreasonable during these periods.[67]

33. We also found that "Complainants' proposed solution is essentially opportunistic, seeking to lock in the potential short-term benefits of RMR cost-of-service contracts during a point in time when supplies are becoming scarce and the fuel prices for marginal gas-fired generation have risen. Doing so would remove the price signal to build non-gas-fired generation, which would provide fuel diversity and lower energy prices to the benefit of consumers."[68] The CT AG also does not dispute the Commission finding that "there have been several periods during the eight years since Connecticut has restructured its power market when mandating a switch to cost-of-service compensation would have resulted in ratepayers paying more than they paid under market-based-rates" as "New England experienced a price decline of 11 percent from 2001 to 2004."[69]

D. Market Price Signals

34. The CT AG argues that the Commission's readiness to award RMR contracts to new and efficient gas baseload generators contradicts the Commission's commitment that New England should have "locational pricing to provide appropriate price signals indicating the value of additional resources or conservation at each node of the transmission system."[70] The CT AG states that, historically, the Commission awarded RMR contracts only to old, inefficient and seldom used generators necessary for reliable

[66] *Id.* at P 81.

[67] *See Interstate Natural Gas Ass'n of Am. v. FERC*, 285 F.3d 18, 32 (D.C. Cir. 2002) (noting that price increases reflecting scarcity are "completely consistent with competition"); *Edison Mission Energy v. FERC*, 394 F.3d 964, 968-69 (D.C. Cir. 2005)(criticizing mitigation program that could "curtai[l] price increments attributable to genuine scarcity"); *see also, e.g., Electricity Consumers Resource Council v. FERC*, 407 F.3d 1232, 1240 (D.C. Cir. 2005) (stating that the balancing of short-term costs against long-term benefits is within the Commission's discretion).

[68] *Id.* at P 79.

[69] *Id.* at P 83.

[70] CT AG Reh'g Request at 19, citing October 11 Order, 117 FERC ¶ 61,038, at P 78.

operation of the grid. But, the CT AG avers, when the Commission decided to freely grant RMR contracts to Bridgeport Energy LLC (Bridgeport) and Milford Power Company, LLC (Milford) (each an owner and operator of new, highly efficient and high capacity factor baseload generation units), the Commission abandoned its commitment to "appropriate price signals" and undermined the development of any potential competitive market.[71] The CT AG explains that the alleged poor financial condition for the Bridgeport and Milford units arose because of the current surplus of highly efficient plants in New England and that a workably competitive market would have corrected the surplus condition. By granting RMR contracts for these entities, the CT AG contends, the Commission essentially signaled to every other New England generator not reaping huge profits that it should step up for its share of RMR money.

35. Finally, the CT AG argues that adoption of the FCM will not cure the infirmities of the New England market structure; rather, its adoption only enhances the current inequities by providing hundreds of millions of dollars in transition payments to the very low cost generators that are already over-recovering in the current "market" and by extending the RMR regime until at least 2010.

Commission Determination

36. The Commission denies rehearing. We responded in detail in the October 11 Order to each of the Complainants' allegations regarding RMR agreements.[72] We need not repeat those findings here.

37. Further, the Commission has not indiscriminately approved RMR agreements for Bridgeport and Milford, as the CT AG claims. The CT AG's argument echoes the argument in the original complaint that the Commission simply "rubber-stamps" RMR agreements.[73] In considering whether to approve the Milford and Bridgeport contracts, the Commission considered two essential benchmarks: first, whether the facilities at issue

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[71] The CT AG refers to the Commission orders *Bridgeport Energy, LLC*, 112 FERC ¶ 61,077 (2005) (*Bridgeport*), and *Milford Power*, 110 FERC ¶ 61,299, *order denying reh'g*, 112 FERC ¶ 61,154 (2005) (*Milford*), as evidence of the Commission's abandoned commitment.

[72] October 11 Order, 117 FERC ¶ 61,038, at PP 59-75.

[73] *See* October 11 Order, 117 FERC ¶ 61,038, at P 70.

were needed for reliability in New England[74] and second, whether the facilities earned sufficient revenues to remain in operation. In *Bridgeport*, where the Commission was not certain that the second benchmark had been met, it set the matter for hearing, stating that "it is not obvious that Bridgeport's several years of significant positive returns followed by two years of 'inadequate' cost recovery meet the Commission benchmark for granting RMR approval."[75] And in *Milford*, the Commission recognized the distinction between RMR agreements it had previously approved for peaking units that were seldom run and frequently subject to mitigation as compared to Milford's new, highly-efficient combined-cycle baseload units, but found that since Milford met the signature benchmarks, an RMR contract was appropriate. As the Commission stated in the October 11 Order, the burden is clearly placed on the generator to establish its financial need for the proposed RMR agreement before the Commission will approve it.[76]

38. Finally, the concerns the CT AG raises about the FCM and the FCM transition payments, which are to be netted against RMR payments, are misplaced in this proceeding. The Commission determined in the FCM settlement proceeding that the FCM will resolve the deficiencies in New England's capacity market, and that, while the transition payments may not be ideal, they are a just and reasonable transition mechanism that enables the New England region to shift to the FCM.[77] The Commission need not revisit here the involved and lengthy considerations that went into development and approval of the FCM settlement, particularly since the CT AG provides no facts to substantiate the claim that adoption of the FCM transition payments enhances current inequities.

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[74] Pursuant to the provisions of Market Rule 1, ISO-NE has the authority to determine whether a generation unit is needed for reliability, and the Commission generally defers to ISO-NE's findings on such matters. The lack of transmission infrastructure in Connecticut has led ISO-NE to determine that virtually all generating units in Connecticut are needed for reliability. However, ISO-NE made individual determinations that both the Bridgeport and Milford units were needed for reliability.

[75] *Bridgeport*, 112 FERC ¶ 61,077 at P 39.

[76] October 11 Order, 117 FERC ¶ 61,038, at P 70.

[77] *See* FCM Settlement Order, 115 FERC ¶ 61,340, *order on reh'g*, 117 FERC ¶ 61,133 (2006) for a full account of the Commission's reasoning in approving the FCM settlement.

The Commission orders:

Rehearing of the October 11 Order is denied, as discussed above.

By the Commission.

(S E A L)

Philis J. Posey,
Acting Secretary.