UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, and Nora Mead Brownell.

New England Power Pool
and
ISO New England, Inc.

Docket Nos. ER02-2330-015,
ER02-2330-016
and ER02-2330-017

ORDER ON REQUESTS FOR REHEARING AND COMPLIANCE FILING

(Issued November 17, 2003)

1. In this order the Commission acts on four requests for rehearing of one Commission order relating to the Standard Market Design for New England (NE-SMD), and a rehearing request of a second Commission order. It also accepts a compliance filing. Customers in New England will benefit from this order because it further facilitates the implementation of effective market rules in New England.

Background

2. The Commission has issued several orders relating to the implementation of NE-SMD by the New England Power Pool Participants Committee (NEPOOL) and ISO New England, Inc. (ISO-NE).[1] On June 6, 2003, it issued an order further addressing the NE-SMD filing and related compliance filings.[2]

3. Timely requests for rehearing and/or clarification of the June 6, Order were filed by ISO-NE, the NEPOOL Industrial Customer Coalition (NICC), NXEGEN, Inc.

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[1] The Commission accepted NE-SMD in an order issued on September 20, 2002, (New England Power Pool and ISO New England, Inc., 100 FERC ¶ 61,287 (2002)), and granted rehearing in part and denied rehearing in part on December 20, 2002 (New England Power Pool and ISO New England, Inc., 101 FERC ¶ 61,344 (2002)).

[2] New England Power Pool and ISO New England, Inc., 103 FERC ¶ 61,304 (2002) (June 6 Order).

(NXEGEN) and PPL EnergyPlus LLC and PPL Wallingford Energy LLC (PPL). Parties also filed multiple pleadings in response to these requests. NXEGEN filed an answer in opposition to ISO-NE's request. Central Maine Power Company (Central Maine), Northeast Utilities Service Company (NUSCO), NEPOOL and ISO-NE filed responses to NICC's request. ISO-NE filed a motion for leave to reply and reply to NXEGEN's request. ISO-NE filed a response to PPL's request. The Connecticut Department of Public Utility Control, the Vermont Department of Public Service, the Vermont Public Service Board and the Massachusetts Department of Telecommunications and Energy (collectively, CT DPUC) filed late comments, and NICC filed an answer to CT DPUC's comments.

4. On July 7, 2003, NEPOOL and ISO-NE made a compliance filing in response to the June 6 Order regarding a stakeholder process to determine an appropriate set of transmission upgrades in Southwest Connecticut (SWCT) to receive socialized cost treatment, and also regarding the use of Real-Time Load Obligation Deviations (RTLOD) rather than Real-Time Adjusted Load Obligation Deviations (RTALOD) to allocate Operating Reserves charges. That filing was noticed in the Federal Register,[3] with protests and motions to intervene due on July 28, 2003. The Maine Public Utilities Commission (Maine Commission) and National Grid USA (National Grid) filed protests, USGen New England, Inc. (USGen) filed comments, and the NRG Companies (NRG) filed a motion for late intervention and protest. ISO-NE and NEPOOL filed a joint answer to the pleadings filed in response to their compliance filing.

5. On August 14, 2003, the Commission issued an order accepting ISO-NE's information report filed on June 18, 2003, but finding that the report was only partially in compliance with the Commission's directive with respect to methods of measuring demand response other than interval metering, and directing ISO-NE to make a further compliance filing within 120 days.[4] On September 12, 2003, ISO-NE filed a request for rehearing of the August 14 Order, and NXEGEN filed a motion for leave to reply and reply to ISO-NE's rehearing request.

6. The above pleadings raise multiple issues, which the Commission will discuss and rule on infra.

[3] 68 Fed. Reg. 42696 (2003).

[4] ISO New England, Inc., 104 FERC ¶ 61,206 (2003) (August 14 Order).

Discussion

A. Procedural Issues

7. Given the early stage of this proceeding and the absence of undue delay or prejudice, we find good cause to grant the untimely, unopposed motions to intervene in the proceedings in which they moved to intervene. See Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2003).

8. Under Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2)(2003), an answer may not be made to a request for rehearing or to an answer, absent authorization by the decisional authority. We will accept the answers filed by ISO-NE and NEPOOL to NICC's request for rehearing regarding to nodal pricing questions, and ISO-NE's reply to NXEGEN's request for rehearing regarding demand response issues, because those answers have provided additional material that has assisted us in considering this matter. We reject all other answers filed here, because they have not provided any new material that has assisted us in considering this matter. We reject the late-filed comments of CT DPUC on the same basis.

B. Demand Response Issues

9. In the June 6 Order, the Commission approved NEPOOL's and ISO-NE's implementation of certain recommendations of the New England Demand Response Initiative (NEDRI) process. Additionally, however, the Commission identified additional NEDRI recommendations that NEPOOL should consider:

> Recommended revisions to ISO-NE programs include (1) inclusion of more flexible bidding processes by removing the requirement that no bid can be smaller than one MW, (2) implementation of an effective, location-based ICAP resource credit, and (3) development of an "economic, price-driven" day-ahead market demand response program by 2004. Additionally, NEDRI's January 15 final report included two new recommendations that were not included in the preliminary recommendations: (1) allowing fixed bids each month or capability period in the Day-Ahead Demand Response program instead of the daily bidding requirement, and (2) permitting demand resources to enroll in both the Day-Ahead and Real-Time Demand Response programs.[5]

[5] June 6 Order at P 68.

10. The Commission directed NEPOOL to consider these recommendations for implementation in or before the summer of 2004, and directed NEPOOL to submit a compliance filing no later than December 31, 2003 indicating whether NEPOOL has approved these recommendations and how the current programs would be revised, if necessary, for implementation by March 31, 2004.[6]

11. NXEGEN, in its request for rehearing, states that the Commission erred in requiring NEPOOL only to "consider" these recommendations, rather than requiring NEPOOL to implement the recommendations, since NXEGEN fears that NEPOOL will not implement these recommendations absent this directive. NXEGEN states that the investment in demand response technologies that will be necessary for the implementation of economic (as opposed to emergency) demand response will not take place unless all of the NEDRI recommendations are implemented. Alternatively, NXEGEN asks the Commission to require that NEPOOL and ISO-NE may decline to implement the NEDRI recommendations only if they can demonstrate that other mechanisms that will accomplish the same results are or will be in place in New England by the end of 2003.

12. Further, NXEGEN asks the Commission to direct NEPOOL and ISO-NE not to accept NEDRI's recommendation of a $50/MWh minimum price bid for any hour in the day-ahead demand response program proposal. NXEGEN asserts that the $50/MWh minimum price will hinder the development of demand response in New England, and is inconsistent with prior Commission statements.[7] NXEGEN states that it recognizes that NEDRI recommended the $50/MWh floor to address gaming concerns, but it nonetheless argues that the floor will restrict the opportunities for demand response providers to maintain the revenue stream necessary to justify the development of sophisticated demand response technologies. NXEGEN further states that gaming could be addressed through the use of monitoring and verification protocols currently being developed by ISO-NE. NXEGEN finally asserts that, if a floor is used, a lower floor than $50 would enable greater participation by demand responders.

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[6] Id.

[7] NXEGEN cites to the Commission's Notice of Proposed Rulemaking regarding Standard Market Design (SMD), namely, Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, 100 FERC ¶ 61,138 at P 276 (2002) (SMD NOPR) (while under some ISO programs the ISO pays end-users to reduce their demand once market clearing prices reach a certain level, "[w]e believe the direct approach of letting demand bid in the market will be less costly" than such a program).

13. ISO-NE in its reply to NXEGEN's rehearing petition states that while it agrees with NXEGEN that implementation of a Day-Ahead Demand Response Program is desirable, NXEGEN's insistence that a Day Ahead Demand Response Program or equivalent program be in place by the end of 2003 is unreasonable, given that ISO-NE and NEPOOL must allocate their limited resources to making numerous market improvements, some of which may logically be required before the implementation of a Day Ahead Demand Response Program ISO-NE asserts that the establishment of a hard deadline for a single market improvement, out of the multiple interrelated market improvements that NEPOOL and ISO-NE are now developing, would divert resources away from projects that might deserve a higher priority and could impede the logical sequence of certain improvements. ISO-NE asks the Commission to leave this matter in the hands of NEPOOL's market participants. With regard to NXEGEN's concern regarding a Resource Adequacy Rule, ISO-NE points out that in an order issued on April 25, 2003,[8] the Commission has already directed ISO-NE to file a mechanism implementing locational or deliverability requirements for resource adequacy by March 1, 2004, for implementation no later than June 1, 2004.

14. Similarly, in its petition for clarification or rehearing, ISO-NE asks the Commission to state that it will not impose a hard deadline for ISO-NE and NEPOOL to implement the Day Ahead Demand Response Program by March 31, 2004.

15. ISO-NE argues that the schedule of market improvements is best determined by the needs and priorities of market participants through the stakeholder process, in part because of the need to provide certainty to parties entering into forward contracts. ISO-NE also states that it would be willing to make periodic filings notifying the Commission of its progress in implementing a Day Ahead Demand Response Program.[9]

16. ISO-NE also asks for clarification as to the scope of the demand response report that the June 6 Order requires it to file by December 31 of each year. ISO-NE states that, if it initiates its evaluation of demand response programs in October 2003, it will not be able to complete an evaluation and report on it by December 31 of that year, and that to meet the December 31 deadline for 2003 and subsequent years, it would have to begin evaluating demand response at a time before most significant demand response events are likely to occur. ISO-NE therefore asks that the Commission modify its requirement so

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[8] Devon Power LLC, 103 FERC ¶ 61,082 (2003) (Devon).

[9] NXEGEN, in its response to ISO-NE's request for clarification or rehearing, opposes ISO-NE's request and urges the Commission to require implementation of a Day Ahead Demand Response Program or equivalent program by the end of 2003.

that ISO-NE may submit its required compliance report on or before March 1 of each year.

17. Finally, in the Commission's August 14 Order, the Commission stated that ISO-NE's June 18, 2003 compliance report was only partly in compliance with the Commission's directive with respect to methods of measuring demand response other than interval metering, and therefore directed ISO-NE to file a subsequent compliance report within 120 days. The Commission stated that it

> agrees with NXEGEN that refusing to permit the use of measurements of current and voltage alone to estimate energy usage appears to be inconsistent with the measurement and metering standards of public utilities in Connecticut. We direct ISO-NE to address this inconsistency in a refiling of the compliance report to be filed with the Commission within 120 days. In this refiled report, the Commission directs ISO-NE to consider the interaction between measurement or lack of measurement of KVAs or power factors and acceptable alternative performance-based measurement techniques, and to either develop alternative measurement strategies which would permit the use of current and voltage measurements alone, or to explain more fully why use of current and voltage measurements alone would be inadequate. [10]

18. In its request for rehearing of the August 14 Order, ISO-NE states that it believes that its June 18 report is in compliance with the Commission's directives. ISO-NE also expresses concern that the Commission has accepted arguments raised by a single market participant, NXEGEN, which has declined to participate in the NEPOOL stakeholder process. ISO-NE asserts that NXEGEN's argument regarding the use of ISO-NE's current and voltage measurements ignores the fact that NXEGEN is not, in fact, required to measure kW directly, and if it cannot do so, NXEGEN can propose to monitor another variable (such as equipment operating hours) and do the necessary calculations to estimate the kW consumption and demand reduction. ISO-NE also states that NXEGEN may measure proxy variables (such as volts, amps and device run times) as the basis for measuring kW usage.

19. ISO-NE further argues that its new performance-based standards cannot be applied to demand response programs other than the Real Time Profiled Response Program. It states that the Commission's requirement in this regard ignores the fact that each program has characteristics specific to it that make the application of performance-based standards to other programs inappropriate. ISO-NE asserts that the uniform imposition of the

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[10] August 14 Order at P 5.

standards urged by NXEGEN would jeopardize such other types of demand response programs. Finally, ISO-NE urges the Commission to protect the stakeholder process by requiring NXEGEN, and other parties, to participate in that process rather than circumventing it by going directly to the Commission with its complaints. NXEGEN, in its response, states that ISO-NE's argument here would prevent any party that is unable to participate in the stakeholder process from being able to seek relief from the Commission.

Commission Response

20. The Commission rejects NXEGEN's rehearing request that the Commission require ISO-NE to implement, as opposed to consider, the NEDRI recommendations. The NEDRI process was designed to develop recommendations for potential application in New England through an extensive, well-informed and expansive stakeholder process, but the process was not intended to circumvent ISO-NE and NEPOOL stakeholder deliberations. Except for the modifications to our direction discussed below, the Commission directs ISO-NE and NEPOOL to consider the NEDRI recommendations listed in the June 6 order for implementation in or before the summer of 2004. As we directed in the June 6 order, the December 31, 2003 compliance report will "indicate whether NEPOOL has approved these recommendations and how the current programs will be revised, if necessary, for implementation by March 31, 2004."[11] If NEPOOL chooses to reject the recommendation, the Commission directs NEPOOL to include in that December 31, 2003 compliance report a detailed explanation and rationale for the rejection, and either (a) a plan for implementing the recommendation on or before the summer of 2005, or (b) a description of how other mechanisms will accomplish the same results and will be in place in New England by the end of 2003.[12]

21. The Commission rejects NXEGEN's request to remove the $50/MWh floor. As the Commission has stated in previous NYISO and ISO-NE orders, the $50/MWh floor "will encourage reduced consumption during peak periods when demand is high relative to supply and when energy prices rise. We also believe that it is reasonable to limit payment, as an incentive for reducing demand, when supply is ample, relative to

[11] June 6 Order at Ordering Paragraph F.

[12] The Commission notes that ISO-NE's assertion in its September 12 rehearing request that NXEGEN has inappropriately sought to circumvent the stakeholder process has merit. Rather than coming immediately to the Commission with its complaints, NXEGEN should seek to resolve its difficulties in the first instance by participating in the stakeholder process.

demand."[13] Consequently, consistent with our directions in past orders, we will not remove or amend the $50/MWh floor.

22. The Commission grants ISO-NE's rehearing request not to impose a hard deadline for the date of implementation of the Day-Ahead Demand Response Program. The Commission is cognizant of the numerous market improvements under development in the next several years and the need to implement these improvements in a logically phased process. Nevertheless, the implementation of a Day Ahead Demand Response Program is important to the development of non-emergency demand response programs in New England, and we therefore direct ISO-NE and NEPOOL to implement the Day Ahead Demand Response Program as soon as it is feasible, but in any case no later than March 31, 2005. Furthermore, we accept NEPOOL's offer to make periodic filings notifying the Commission of its progress in implementing a Day Ahead Demand Response Program. These filings will be required to be filed on or before December 31, 2003, March 31, 2004, June 30, 2003, September 30, 2003, and December 31, 2004.

23. The Commission rejects ISO-NE's request for a modification of the deadline for filing the annual evaluation reports. Extension of the deadline to March 31 will negate the usefulness of the evaluation. In order to be useful for future ISO-NE stakeholder processes and Commission approval of changes to the demand response programs prior to the summer peak periods, the results of the evaluation need to be completed no later than late December. The December 31, 2003 deadline is consistent with the timeframes we have directed for similar evaluation reports from PJM and NYISO.

24. The Commission reiterates its direction that ISO-NE will need to submit a new compliance report on the application of methods of measurement other than interval metering to demand response programs other than the Profiled Demand Response program. The intent of the December 20 Order and the August 14 Order was for ISO-NE to develop alternative measurement procedures for these other programs, where feasible.

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[13] New York ISO, Inc., 102 FERC ¶ 61,313 at P 23 (2003). See also New England Power Pool and ISO New England, Inc., 101 FERC ¶ 61,344 at P 44 (2002) ("we will deny the request by NXEGEN to remove the $50/MWH bid floor in the Day-Ahead Demand Response . . . . The program is intended to encourage reduced consumption during peak periods when demand is high relative to supply energy and energy prices rise. It is reasonable to limit the additional payment incentive for reducing demand to periods when demand is high relative to supply, and not to offer the incentive when supply is ample relative to demand. Establishing a suitable bid floor or minimum triggering price, as proposed by ISO-NE, is one way to target the incentives to these tight-supply periods. Moreover, the bid floor associated with the Demand Response Program would not prevent customers from submitting ordinary price bids below $50/MWh for energy in the day-ahead energy market").

ISO-NE's rejection of the need to examine and develop alternative measurement procedures based on a "reasonable reading of that Order" is not responsive to our direction. The Commission is cognizant that the Measurement and Verification plan included in the newly-filed Appendix E may not be appropriate for demand response programs that place a premium on more timely and accurate information, and we do not, therefore, direct the uniform application of Appendix E. Nevertheless, our original direction in the December 20 Order was to foster the exploration and development of measurement techniques other than interval metering that would provide "timely and accurate information" for these programs. ISO-NE's filings and rehearing requests have demonstrated that it has not complied with this direction. At a minimum, ISO-NE must demonstrate why it considers methods other than interval metering to be inappropriate for demand response programs other than the Profiled Demand Response Program. ISO-NE must also provide a detailed justification for that conclusion (including, if relevant, stakeholder or staff analyses of this question), so as to enable other parties who might be able to propose methods other than interval metering to do so in the most informed manner possible. As discussed above, the Commission required ISO-NE in its August 14 Order to make a filing within 120 days of that order that would provide the required information regarding alternative methods of measurement, and once ISO-NE complies with that obligation, it will have complied with the obligation placed on it in our December 20 Order as well. [14]

25. The Commission accepts ISO-NE's explanation that non-kW measurements can be used in the June 18 monitoring and verification plan submitted by ISO-NE. ISO-NE has adequately responded to NXEGEN's protest and has met the Commission's request in the August 14 Order for additional explanation.

C. Nodal Pricing

26. In the June 6 Order, the Commission accepted arguments by ISO-NE and NEPOOL regarding the technical impediments to allowing nodal pricing and zonal pricing within the same zone, and therefore stated that it would not require "piecemeal implementation of nodal pricing," i.e., that it would permit ISO-NE to implement nodal pricing solely when it could do so within an entire zone. The Commission further stated, in response to a query by NUSCO, that because nodal pricing was discussed in ISO-NE's July 15, 2002 filing as a key feature of NE-SMD which would be implemented as soon as possible, NUSCO "may consider itself on notice . . . now" of the transition to nodal pricing.[15]

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[14] August 14 Order at P 5, 7.

[15] June 6 Order at P 79.

27. NICC, in its request for clarification or rehearing, asks the Commission to reconsider its ruling that all customers in a zone must remain subject to zonal pricing until nodal pricing is available for all customers within the zone. NICC asserts that the implementation of Locational Marginal Pricing (LMP) on a nodal basis is key to allowing customers to respond to price signals on a pinpoint basis, whereas the operation of LMP on a zonal basis, which relies on the socialization of energy and congestion costs, results in customers within a particular area remaining with standard offer and provider-of-last-resort mechanisms. NICC asserts that the Commission's "all or nothing" approach penalizes those customers who are technologically able to see and pay nodal prices by forcing them to pay zonal prices simply because they are within a zone where all customers cannot engage in nodal pricing (and, in essence, forces those customers to subsidize all customers within the zone). NICC also argues that the "all or nothing" approach will provide electric distribution companies (EDCs) with a means of delaying implementation of nodal pricing for load, thus delaying indefinitely the full benefits of LMP. NICC further cites a recent Commission order requiring implementation of nodal pricing in PJM within 120 days.[16] NICC asks the Commission to clarify that a nodal pricing option must be made available immediately to those customers able to implement it.

28. NICC further states that in the June 6 Order, the Commission stated that "ISO-NE and NEPOOL anticipate that [the process of implementing nodal pricing] will take approximately 18 months starting from the implementation of NE-SMD on March 1, 2003."[17] NICC believes that this 18-month period should have started on September 20, 2002, the date on which ISO-NE and NEPOOL were ordered to implement a nodal pricing option for load, and not on March 1, 2003.[18]

29. ISO-NE, NEPOOL, Central Maine and NUSCO oppose NICC's rehearing request. ISO-NE and NUSCO state that the Commission's ruling in the June 6 Order was clear and does not require clarification. ISO-NE points out that NICC's concerns regarding the continuing cross-subsidization that could occur when some customers in a zone could

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[16] Occidental Power Services, Inc. v. PJM Interconnection, LLC, 103 FERC ¶ 61,285 (2003) (Occidental).

[17] NICC petition for rehearing, citing June 6 Order at P 25 n.50.

[18] See New England Power Pool, et al., 100 FERC ¶ 61,287 at P 70, 72 (2002).

implement nodal pricing, but are not permitted to, will not be addressed by NICC's proposed remedy. ISO-NE states:

> [A]llowing some customers within a zone to receive nodal pricing while others cannot, as NICC requests, would exacerbate cross-subsidization problems. Those select customers that could receive nodal pricing sooner may indeed be relieved of subsidization obligations, but with piecemeal implementation, those obligations are merely shifted to a smaller set of customers that cannot yet receive nodal pricing. [19]

30. ISO-NE further states that NICC's proposal could disproportionately harm residential customers, who are likely to see price increases for standard offer service if larger commercial and industrial customers obtain service from wholesale suppliers at nodal prices. ISO-NE also notes that NICC's citation to Occidental as requiring implementation of nodal pricing in New England is inapposite, because the settlement software used in New England was custom-developed to support unique New England requirements and is substantially different from the software used in PJM. Finally, ISO-NE states that the process by which improvements to the New England markets are implemented is currently being discussed by the stakeholders, who are setting priorities, and that a hard deadline for implementing specific market improvements would jeopardize this comprehensive planning process.

31. Central Maine states that, as an electric distribution company, it has no intention of delaying the implementation of full nodal pricing. Rather, Central Maine asserts, the resolution of many issues relating to the implementation of nodal pricing will require the input and cooperation of all New England participants and state regulators, and that ISO-NE's collaborative process to achieve this goal should be permitted to work, unimpeded by the Commission. Central Maine also asks the Commission to instruct NICC to work through the appropriate NEPOOL governance process to address its concerns regarding the implementation of nodal pricing.

32. NEPOOL and NUSCO state that the Commission's June 6 Order already resolved the issues raised here by NICC. NEPOOL also notes that the initial 18-month estimate for the implementation of nodal pricing was a preliminary estimate rather than a rigid deadline. It points out that the NEPOOL Meter Readers Working Group (NMRWG) is working with ISO-NE on nodal pricing issues, and that as part of that group's latest activities, some participants and regulators have questioned whether and when a change to full nodal pricing is necessary or desirable. Thus, NEPOOL asserts, it is not realistic

[19] ISO-NE response to NICC's petition at 5.

for ISO-NE and NEPOOL to finalize the necessary arrangements for full nodal pricing 18 months from September 20, 2002.

33. In its late-filed comments, CT DPUC also urges the Commission to reject NICC's request and states that it supports resolution of the question of when nodal pricing should be implemented for load through a New England stakeholder process. They note that state regulators in Connecticut, Vermont and Massachusetts believe that the advantages of nodal pricing for load have not been demonstrated, and thus, some states may wish to continue to offer retail rates that are not based on nodal pricing. Thus, CT DPUC argues, the price signals to which NICC points may, in any cases, be muted by a retail rate methodology. NICC in its answer to CT DPUC's comments also supports resolution of nodal pricing issues through a stakeholder process.

Commission Response

34. We will deny NICC’s request to reconsider our ruling that all customers in a zone must remain on zonal pricing until nodal pricing is available for all customers within the zone. As NEPOOL states, NE-SMD software and business systems are capable of accommodating full nodal pricing for load, but cannot now accommodate providing loads within a zone with the choice between nodal and zonal. ISO-NE states that the cost and implementation effort for such a "nodal choice" practice within a zone would be significantly greater than simply implementing full nodal pricing in the zone. We are persuaded by NEPOOL’s and ISO-NE's answers that implementing nodal choice within a zone could take away resources from other high-priority market improvements, such as locational capacity markets and co-optimized reserve markets.

35. While Occidental dealt with issues similar to those raised by NICC, such as customer capability for hourly-interval metering in determining whether a customer could be billed at the nodal price, the Commission’s decision in Occidental, as reiterated on rehearing,[20] was based solely on the provisions of the existing PJM tariff. NE-SMD is a different situation in that the nodal/zonal issue is still evolving within the stakeholder process. Therefore, we are not persuaded by NICC’s arguments that our Occidental decision forms a basis for applying nodal pricing on a piecemeal basis within the zones in NEPOOL. While our previous NE-SMD orders stated our interest in implementing nodal pricing for load, we did not impose a firm deadline for implementation. NEPOOL states that it would not be in a position to finalize the necessary arrangements to allow for full nodal pricing for load within the time frame requested by NICC, and NICC has made no showing to the contrary. We will therefore deny NICC’s request to require ISO-NE to

[20] 104 FERC ¶ 61,289 (2003).

implement full nodal pricing for load throughout New England within 18 months of our September 20, 2002 order.

D. PUSH Bid Issues

36. In its earlier Devon order, the Commission approved the concept of Peaking Unit Safe Harbor (PUSH) bidding for seldom-operated units. The formula set forth in Devon for determining PUSH bid thresholds was the "sum of the unit's variable cost and the adjusted fixed cost adder," which "should be designed to recover the unit-specific fixed costs (adjusted downward, in the case of units covered by RMR contracts, to account for the costs recovered in the RMR contract) over the number of megawatt hours supplied in the preceding year."[21]

37. PPL states that in the June 6 Order, the Commission stated that the PUSH reference level would be calculated as the sum of that unit's variable costs and its fixed costs for 2002, divided by the number of MWh supplied in 2002.[22]

38. PPL seeks clarification that in the June 6 Order, the Commission did not intend to change the formula set forth in Devon, and asks the Commission to make clear that 2002 variable costs are not to be used in the variable cost component of its PUSH bid formula. PPL asks the Commission to clarify that, in stating that "variable costs and [the unit's] fixed costs for 2002" would be used to develop PUSH reference levels, it intended the word "2002" to apply only to the fixed cost component. PPL argues that it is inappropriate for 2002 variable costs to be used in developing PUSH reference levels, because while fixed costs may be stable, variable costs are not, and that gas costs have risen approximately 60 percent in 2003 over their 2002 levels. PPL therefore asserts that any formula that bases maximum bidding levels on variable costs incurred in 2002 will impair the ability of a generator using natural gas to recover its variable costs.

39. ISO-NE in its response to PPL's rehearing request[23] states that the methodology it uses for calculating PUSH reference levels relies on 2002 inputs for all variable costs except fuel. ISO-NE states that it bases variable fuel costs on current indices. It states

[21] Devon at P 34, 33.

[22] June 6 Order at P 27.

[23] ISO-NE states that it is filing this response both to PPL's request for clarification or rehearing in ER02-2330, and to a motion to intervene and protest filed by the Connecticut Municipal Electrical Energy Cooperative (CMEEC) in Docket Nos. ER03-563-011 and ER03-421-004. Since CMEEC's motion was not filed in this docket, the Commission will disregard any responses made by ISO-NE to this pleading.

that it believes that fuel costs are sufficiently volatile to require the use of current data, but that non-fuel variable costs are far less volatile, and so may be recovered by using 2002 data. ISO-NE states that it considers this methodology to be in compliance with Devon.

Commission Response

40. The Commission grants PPL's request for clarification in part, and states that it was not the Commission's intention in the June 6 Order to make any determinations regarding the PUSH mechanism or the related PUSH market rules. The June 6 Order only discussed the PUSH mechanism generally as it related to requests for rehearing on other issues in that proceeding. PUSH mechanism issues were addressed in Devon and the resulting market rules filed by ISO-NE on May 30, 2003[24] to which PPL refers, in the rehearing order in Devon [25] (which the Commission had not yet issued at the time of the June 6 Order). Therefore, paragraph 27 of the June 6 Order was not intended to address or change decisions made in the Devon proceedings with regard to the PUSH mechanism. We will not address the issues raised by PPL regarding the calculation of the variable cost component of the PUSH bid level here, because the June 6 Order did not address the specifics of the formulas for determining the PUSH bid levels.

E. Operating Reserves Charges

41. National Grid and ISO New England have differing views on the proper method to allocate certain Operating Reserve costs. These costs result from committing generators to ensure that the ISO is able to meet its forecasted load and Operating Reserve requirements for the day-ahead and real-time markets. These charges are, in part, created by the under-commitment of resources in the day-ahead market or by unanticipated changes in system conditions. Charges are assessed to participants based on the difference in scheduled energy commitments in the day-ahead market and the actual real-time energy commitments. The disagreement between National Grid and ISO-NE centers whether to adjust this difference for certain internal bilateral transactions.

42. There are two types of such bilateral transactions: Internal Bilaterals for Load (IBLs) and Internal Bilaterals for Market (IBMs). Both bilateral transactions are purely contractual and have no impact on the physical dispatch of the power system. A Load Serving Entity (LSE) entering into an IBM transfers only the responsibility for providing

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[24] See ISO-NE compliance filing of May 30, 2003 in Docket ER03-563-007 and amended June 10, 2003 in ER03-563-010.

[25] Devon Power Company, 104 FERC ¶ 61,123 (2003).

energy to its load; conversely, an LSE entering into an IBL transfers both the obligation to provide energy to load and the obligation to provide associated ancillary services,[26] including the Operating Reserve costs at issue here.

43. ISO-NE and NEPOOL currently provide that, when allocating these Operating Reserve charges, the difference between a participant's day-ahead and real-time obligations is not adjusted to account for the participant's use of IBMs; National Grid believes that that difference should be adjusted to account for a participant's IBMs. In the June 6 Order**,** the Commission concluded that the January 21 compliance filing did not sufficiently clarify the process for allocating Operating Reserve costs. The Commission therefore required NEPOOL and ISO-NE to address National Grid's concerns.

44. In their compliance filing, NEPOOL and ISO-NE state that, if a participant has no Real Time Load Obligation Deviation (RTLOD) – that is, no deviation between the amount of energy that it committed to provide on a day-ahead basis, and the amount that it actually provides in real time – that participant will incur no demand-related Operating Reserve charges.[27] NEPOOL and ISO-NE also state that a party can avoid the occurrence of any RTLOD deviations by how it chooses to participate in the Day-Ahead Market.

45. NEPOOL and ISO-NE also state that, although LSEs are initially responsible for Operating Reserve Charges, they may transfer their obligations through bilateral contracts with other entities (such as IBLs). ISO-NE and NEPOOL assert that IBMs, by contrast, which solely transfer the financial responsibility for providing energy from the buyer to the seller, have no impact on the portion of Operating Reserve costs for which each party is responsible. ISO-NE and NEPOOL state that IBMs provide market participants additional contracting flexibility and opportunities to manage risk, and that allocating Operating Reserve Charges partly on the basis of IBMs, which do not cause any change in actual Operating Reserve responsibility, would effectively eliminate the ability of market participants to use IBMs as a hedging mechanism solely for energy costs, thus reducing liquidity and increasing market risk.

46. National Grid, in its protest to NEPOOL's and ISO-NE's filing, states that the compliance filing fails to adequately support or modify the use of RTLOD to allocate Operating Reserve charges, and merely repeats arguments already analyzed and rejected by the Commission. National Grid again requests the Commission order ISO-NE and

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[26] See earlier answer of ISO-NE and NEPOOL filed November 27, 2002 at 22.

[27] NEPOOL and ISO-NE compliance filing at 5-6. NEPOOL and ISO-NE note that a participant might, however, incur generation-related Operating Reserve charges.

NEPOOL to use Real Time Adjusted Load Obligation Deviation (RTALOD) – namely, the deviation between day-ahead and real-time purchases as adjusted by IBMs – to allocate Operating Reserve charges. [28]

Commission Response

47. The Commission finds that ISO-NE and NEPOOL have complied with the directives of the June 6 Order by providing an explanation of the basis for their use of the RTLOD method for allocating real-time Operating Reserve costs, and have also demonstrated that it is superior to the method proposed by National Grid.

48. As ISO-NE and NEPOOL point out, participants have a variety of contractual instruments at their disposal to hedge or shift the risks of their obligation to serve load, including IBLs and IBMs. The use of RTLOD to measure the additional real-time Operating Reserve costs allocated to participants enables these two types of contractual arrangements to remain distinct. If an LSE enters into an IBM, if its load requires additional energy in real time, even though the LSE's counterparty will be responsible for providing that energy, the LSE will still be responsible for the associated additional Operating Reserve charges. If, on the other hand, an LSE enters into an IBL, if its load requires additional energy in real time, the LSE's counterparty will be responsible for both that additional energy and any additional Operating Reserve charges.

49. National Grid proposes that ISO-NE instead assess additional real-time Operating Reserve charges by using the deviation between day-ahead and real-time purchases as adjusted by IBMs. Under this method, however, the distinction between IBLs and IBMs would disappear. Thus, market participants would be deprived of the opportunity to make their own choices as to how much or in what way to hedge or reallocate their risks through private contract. ISO-NE and NEPOOL have indicated that

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[28] NEPOOL and ISO-NE also explain that, as opposed to the treatment of Operating Reserve charges, it is appropriate to use RTALOD to assess charges associated with Emergency Energy, based on the impact that the purchase or sale of Emergency Energy can have on LMP. A sale of Emergency Energy to a neighboring control area will cause the LMP at certain nodes to increase. Although the LMP has already been paid to the participants in the NEPOOL market, the neighboring control area will be paying the external LMP plus an additional 10 percent, which must be allocated back to the participants who were affected by the increased LMPs. Similar changes will occur when when NEPOOL is required to purchase Emergency Energy, also causing changes in LMP at some nodes. ISO-NE and NEPOOL state that using RTALOD as an allocator thus allows for the additional charges or revenues related to the purchase or sale of Emergency Energy to be allocated to the parties directly exposed to the increase or decrease in LMPs.

the flexibility to choose between IBLs and IBMs is valuable to many market participants.[29]

50. Additionally, National Grid's concern that the use of the RTLOD measurement will force parties to bear some of the costs associated with the real time market even if they choose not to transact in that market is unfounded. If an LSE purchases enough energy in the day ahead market to serve the needs of its load, there will be no deviation between the day-ahead purchase and the amount of energy taken in real time, so that the LSE will pay no additional real-time Operating Reserve costs. However, if an LSE purchases less energy in the day-ahead market than its load takes in real time, there will have been a deviation between that load serving entity's day-ahead and real-time purchases, and ISO-NE must adjust upward the amount of that party's Operating Reserve responsibility in real time. If an LSE purchases sufficient energy on a day-ahead basis to serve its load, it will largely be able to avoid having to transact in the real-time market, and will thus be able to avoid any real-time Operating Reserve costs. (While unforeseen circumstances, such as load unexpectedly taking more energy than anticipated, might force an LSE to purchase a limited amount of energy in the real-time market, an LSE seeking to insulate itself against this possibility would have contractual instruments available to it, including IBLs.)

51. In support of its position, National Grid cites to an earlier Commission ruling regarding the allocation of energy uplift by contract among parties.[30] In that case, the Commission ruled that parties who do not participate in New England's energy markets, and therefore do not benefit from those markets, should not be required to pay the costs of energy uplift, which is associated with the operation of those markets. National Grid asserts that similarly here, the Operating Reserves charges are costs associated with the real-time energy market, and participants who do not benefit from the real-time energy market should not pay those costs. National Grid also argues that in the Energy Uplift Orders, the Commission was not swayed by arguments that its ruling would reduce the parties' contracting flexibility.[31]

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[29] November 27, 2002 answer of ISO-NE and NEPOOL at 23, citing request for rehearing of New England Suppliers filed October 21, 2002, at 11-13. New England Suppliers state that the availability of IBMs, which enable parties to trade pure energy, contributes to the development of a liquid and robust market for energy trading.

[30] ISO New England and NEPOOL, 95 FERC ¶ 61,384 at 62,429, reh. denied, 100 FERC ¶ 61,245 (2002) (Energy Uplift Orders).

[31] February 11, 2002 protest of National Grid at 4, appended as Attachment A to National Grid's July 28, 2003 protest here.

52. The two situations, however, are not analogous. The Energy Uplift orders issued in 2002 involved the allocation of costs among the parties to contracts that had been entered into under a regulatory regime under which many more costs were socialized, and parties had significantly less ability to affect their costs and expenses. By contrast, ISO-NE's use of the RTLOD measure to determine (in part) the allocation of Operating Reserve costs is a part of New England's move to NE-SMD, where parties have the ability, through the existence of both a day-ahead and a real-time market, to hedge their exposure to unanticipated costs in the real-time market by acquiring sufficient energy in the day-ahead market. Additionally, parties may protect themselves against unexpected events (such as load taking an unanticipated amount of energy) through the use of IBLs. Thus, market participants now are more able proactively to determine their own Operating Reserve costs, and to hedge against unexpected costs, than they were when the Commission issued the Energy Uplift orders. Moreover, as noted above, under the method proposed by National Grid, the distinction between IBMs and IBLs would disappear, and parties would not be able to trade energy only, whereas under the method proposed by ISO-NE and NEPOOL, parties would be able to trade energy and associated obligations, or to trade energy only – a level of flexibility which, as noted above, is desired by market participants. The Commission thus finds ISO-NE's and NEPOOL's choice superior to an alternative which would limit parties' trading flexibility.

53. Thus, the Commission denies National Grid's request that it order NEPOOL and ISO-NE to use RTALOD rather than RTLOD to assess Operating Reserve charges.

F. Transmission Cost Allocation

54. In the July 7 compliance filing, ISO-NE and NEPOOL also provided a proposal for a stakeholder process to resolve the question of which transmission upgrades in SWCT should receive socialized cost treatment. They stated that the NEPOOL Participants Committee has approved transmission cost allocation amendments (TCAs) to the NEPOOL tariff that address this question, and NEPOOL expects to file the TCAs with the Commission shortly. The Maine Commission and NRG state that they are protesting this portion of the compliance filing.

55. The Maine Commission and NRG state that they are protesting this portion of the compliance filing. The TCAs have now been filed with the Commission in Docket No. ER03-1141-000. The issue of the allocation of the costs of transmission upgrades for SWCT will be decided in that docket, and NEPOOL's and ISO-NE's compliance filing on that subject, as well as the Maine Commission's and NRG's protests, have thus been rendered moot.

The Commission orders:

(A) The requests for rehearing and/or clarification are hereby granted in part and denied in part, as discussed above.

(B) NEPOOL's and ISO-NE's compliance filing is hereby accepted.

(C) As discussed above, ISO-NE and NEPOOL are hereby required to implement a Day Ahead Demand Response Program as soon as it is feasible, but no later than March 31, 2005. NEPOOL is directed to make filings notifying the Commission of its progress in implementing a Day Ahead Demand Response Program on or before December 31, 2003, March 31, 2004, June 30, 2003, September 30, 2003, and December 31, 2004.

(D) If, as discussed above, NEPOOL chooses to reject the recommendations of the NEDRI process, it must include in its December 31, 2003 compliance report a detailed explanation and rationale for the rejection, and either (a) a plan for implementing the recommendation on or before the summer of 2005, or (b) a description of how other mechanisms will accomplish the same results and will be in place in New England by the end of 2003.

By the Commission.

(S E A L)

Linda Mitry,
Acting Secretary.