101 FERC ¶ 61, 344
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. ER02-2330-001 and EL00-62-052
New England Power Pool and ISO New England, Inc.	Docket Nos. ER02-2330-002 and EL00-62-053
New England Power Pool and ISO New England, Inc.	Docket Nos. ER02-2330-003 and EL00-62-054

ORDER ON REHEARING AND
ACCEPTING COMPLIANCE FILINGS

(Issued December 20, 2002)

1. In this order, the Commission grants in part and denies in part requests for rehearing filed in response to our order accepting the Standard Market Design filed by the New England Power Pool Participants Committee (NEPOOL) and ISO New England, Inc. (ISO-NE). We also accept two compliance filings made in response to that order.

BACKGROUND

2. On September 20, 2002, the Commission issued an order accepting a new Standard Market Design for New England (NE-SMD).[1] Among other provisions, in order to send correct market signals as to congestion, NE-SMD implements Locational Marginal Pricing (LMP) for New England, and also provides parties with a means to

[1] New England Power Pool and ISO New England, Inc., 100 FERC ¶ 61,287 (2002) (September 20 Order).

hedge against congestion costs through the purchase of Financial Transmission Rights (FTRs).[2]

3. NE-SMD replaces NEPOOL's former market rules with a new Market Rule 1. Appendix A to Market Rule 1 lays out its approach for monitoring and mitigating market power.[3] This approach identifies resources potentially exercising market power by comparing their current energy supply offers with a proxy for what the resource would bid if it had no market power. When the supply offer significantly exceeds the proxy – referred to as the reference price – an investigation is triggered that may result in mitigation. The degree to which a supply offer may exceed the reference price before triggering an investigation depends on whether transmission constraints affect a unit's dispatch or whether it is located in a chronically constrained area identified as a Designated Congestion Area (DCA).[4]

4. Further, units within DCAs which must be run at certain times to alleviate transmission congestion, and so are likely to have market power at those times, may be classified as Reliability Must-Run (RMR) units. If RMR units are not adequately compensated under the proxy CT safe harbor price, they may apply for a special compensation arrangement under specified RMR contracts.

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[2]September 20 Order at PP 10, 14-15. FTRs are uni-directional rights/obligations to collect/pay the difference in the congestion component of the LMP between points of receipt and delivery. The registered FTR holder is entitled to receive a share of congestion revenue collected by ISO-NE associated with the path between the points of receipt and delivery for each FTR that it holds. One hundred percent of FTRs will be auctioned.

[3]September 20 Order at PP 16-18.

[4]ISO-NE's plan provides for three levels of mitigation. When the transmission system is unconstrained, offers to supply energy are not investigated unless they exceed their corresponding reference price by the lesser of 300 percent or $100 per MW-hour. If a transmission constraint causes a unit to be dispatched above the level it would have been dispatched absent the constraint, its supply offer will be investigated if it exceeds its corresponding reference price by the lesser of 50 percent or $25, unless the unit is in a DCA. For units within DCAs, New England will develop a pre-specified congestion threshold that is an estimate of the price needed to recover the annual cost of a new combustion turbine unit for that region over the number of hours it is expected to operate during the year (proxy CT). This proxy CT price will serve as a "safe harbor" bid for all units in the DCAs at all times.

5. Timely requests for rehearing of the September 20 Order were filed by the Connecticut Department of Public Utility Control (Connecticut PUC), ISO-NE, ISO-NE and NEPOOL jointly, United Illuminating Company and Vermont Electric Company (United Illuminating), Northeast Utilities Service Company and Select Energy (NU), National Grid/United Illuminating Company (National Grid), Massachusetts Municipal Wholesale Electric Company (MMWEC), NSTAR Electric & Gas Corporation (NSTAR), New England Suppliers, the NRG Companies (NRG), NXEGEN, Constellation Power Source, Inc. (Constellation), MASSPOWER and Pittsfield Generating Company, L.P.. (MASSPOWER), Vermont Public Power Supply Association (VPPSA), Duke Energy North America (DENA), Vermont Department of Public Service (VDPS), the Attorney General of Connecticut (CTAG) and the NEPOOL Industrial Customer Coalition (NICC).

6. A response to Connecticut PUC's request for rehearing was filed by the Maine Public Utilities Commission, Massachusetts Department of Telecommunications and Energy, the Rhode Island Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, and the Attorney General of Rhode Island (New England Commissions), and Connecticut PUC filed a response to New England Commissions' response. A response to MASSPOWER's request for rehearing was filed by ISO-NE, and National Grid filed an answer to ISO-NE's response. A response to National Grid's request for rehearing was filed by MMWEC. A response to ISO-NE's and NEPOOL's joint request for rehearing and Constellation's request for rehearing was filed by National Grid. A response to NSTAR's request for rehearing was filed by NU.

7. NEPOOL and ISO-NE made compliance filings on October 7, 2002 and on October 21, 2002.

8. Notice of the October 7 compliance filing was published in the Federal Register,[5] with interventions and protests due on or before October 28, 2002. A motion to intervene was filed by the Vermont Electric Company (VELCO). Protests or comments were filed by DENA, the Electric Power Supply Association (EPSA), the New England Conference of Public Utility Commissioners (NECPUC), and PG&E National Energy Group, et al. (PG&E). A motion to intervene and protest was filed by Edison Mission Energy, Inc., et al. (Edison Mission).

9. Notice of the October 21 compliance filing was published in the Federal Register,[6] with interventions and protests due on or before November 12, 2002. Motions to

[5] 67 Fed. Reg. 66,625 (2002).

[6] 67 Fed. Reg. 67,168 (2002).

intervene and protest were filed by National Grid and Central Vermont Public Service Corporation, et al. (Central Vermont). Protests or comments were filed by Central Maine Power Company (Central Maine), DENA, the Long Island Power Authority (LIPA), MASSPOWER, and NU. PPL Wallingford Energy, et al. (PPL) filed a motion to intervene out of time. Trans-Canada Power Marketing, Ltd. (TCPM) filed an answer to National Grid's protest. NEPOOL and ISO-NE filed a joint answer to the protests of Central Maine, MASSPOWER, DENA, LIPA, National Grid and Central Vermont. MASSPOWER filed a response to NEPOOL's and ISO-NE's answer, and MASSPOWER filed a response to the answer. National Grid filed an answer to that answer.

10. By notice issued October 11, 2002, the Commission invited parties to file comments on the panel discussions concerning demand response during the Commission's October 9, 2002 public meeting. NXEGEN filed comments in response to that notice.

DISCUSSION

Procedural Issues

11. The notices of intervention and the timely, unopposed motions to intervene serve to make the intervenors parties to this proceeding. See 18 C.F.R. § 385.214 (2002). 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.

12. Under Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2)(2002), an answer may not be made to a protest or an answer unless permitted by the decisional authority. We will accept the answer filed by NEPOOL and ISO-NE to the protests to the October 21 compliance filing, and National Grid's answer to the response filed by MASSPOWER, because they provide new material that has assisted us in considering this matter. We will reject all of the remaining answers, and answers to answers, filed by the parties, because they have not provided any new material to assist us in considering this matter.

Analysis

13. We will grant rehearing in part and deny rehearing in part, and accept the compliance filings in part and reject the compliance filings in part, as follows.

I. Market Issues

A. Market monitoring and mitigation issues

14. Safe harbor provision. ISO-NE seeks rehearing of the Commission's ruling as to when the proxy CT safe harbor may apply. The Commission accepted the proxy CT safe harbor proposal in the September 20 Order, but limited the hours during which it could apply, ruling that it could apply "only when transmission constraints and demand conditions in the DCA require the dispatch of all capacity of all available resources within the DCA."[7]

15. ISO-NE argues that this interpretation would vitiate the policy purpose of the proxy CT provision -- namely, to incent the construction of new generation in chronically constrained areas. ISO-NE believes that the former mitigation rules provided a disincentive to generators to locate new projects within DCAs, since units in those areas were frequently run out of merit to alleviate constraints, and, as a result of the price mitigation for must-run units, were paid only a small amount above their operating marginal costs. Further, since new units, which would also be run primarily out of merit order, would also not be able to recover their fixed or going-forward costs (absent special RMR agreements), few new units were constructed.[8] ISO-NE sought to address this problem by adopting an LMP market design and proposing a proxy CT safe harbor bid to better enable generators within DCAs to receive a scarcity price and recover their fixed costs.

16. Under the Commission's modification of the proxy CT proposal, however, ISO-NE asserts that the safe harbor provision would seldom, if ever, be available, as all capacity of all available resources within a DCA is dispatched only under very extreme conditions. ISO-NE states that under this standard, in 2001 the proxy CT safe harbor would have been available for only 2 hours, and in only one of the four possible DCAs.

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[7] September 20 Order at P 45.

[8] ISO-NE cites the testimony of its independent market consultant showing between 1999 and the end of 2002, approximately 8,000 MW of new capacity will have been installed in the NEPOOL control area, but only 1,000 MW of that new capacity is located in one of the four most chronically constrained areas in New England. ISO-NE Request for Rehearing at 6, citing Direct Testimony of Robert G. Ethier at 19, Docket No. ER02-2330-000 (July 13, 2002).

Moreover, for the proxy CT provision to incent new construction, generators must know ahead of time that when they bid at or below the proxy CT threshold, they will not be subject to mitigation, but the Commission's modification removes that certainty. ISO-NE further asserts that it believes that competition inside and outside of each DCA during non-constrained hours, and vigorous market monitoring, would prevent abuse of the proxy CT provision. ISO-NE suggests that, if the Commission continues to be concerned about possible abuses, ISO-NE could include a sunset provision that would automatically suspend application of the proxy CT safe harbor when certain conditions are met, such as it having been triggered for a certain number of hours per year. Further, ISO-NE's market monitor could immediately suspend the proxy CT mechanism upon a determination that such a suspension is necessary. Alternatively, if the Commission continues to believe that its modification is necessary, ISO-NE asks that the proxy CT provision be removed from Market Rule 1 altogether, without prejudice to refiling subject to a new stakeholder process.

17. New England Suppliers similarly opposes the Commission's restriction on when the safe harbor provision may operate, stating that this will undermine the purpose of incenting generation to locate within DCAs. Connecticut PUC also asserts that the Commission's restriction of the safe harbor provision may be too restrictive, and would support a restriction tied to out-of-merit dispatch, rather than to dispatch of all available capacity.

18. Other parties take the opposing view. In their requests for rehearing of the September 20 Order, NSTAR also approves the restrictions on the safe harbor provision. NU opposes the safe harbor provision altogether, arguing that it allows generators to exercise unrestricted market power. If the Commission allows the retention of the safe harbor provision, however, NU asks for clarification as to whether the phrase "when transmission constraints and demand conditions in the DCA require the dispatch of all capacity of all available resources within the DCA" includes units loaded with energy only, or units for reserve and contingency purposes, and suggests the former. It also suggests that "resources" should include transmission facilities. NU also wants the Commission to clarify that ISO-NE must file, as an amendment to Market Rule 1, the process for determining when all capacity is dispatched. It further asks the Commission to interpret "demand conditions" as referring to only load served within the DCA, and excluding external transactions.

19. Commission response: During a reserve shortage, the prices for energy and reserves should rise to reflect supply scarcity to encourage reductions in demand and additional investment in supply. In this circumstance, scarcity pricing is appropriate. In our September 20 Order we intended to restrict the use of the CT proxy as a safe harbor

bid to those hours when there was a reserve shortage in the DCA. ISO-NE has persuaded us, however, that restricting the use of the safe harbor bid to defined scarcity periods would require that generators accurately assess when scarcity conditions would arise and then bid the CT proxy to obtain the scarcity price; and this uncertainty could discourage CT proxy bids and thus fail to achieve scarcity pricing needed to support entry in DCAs. We agree this could be a consequence of our modification. We thus grant rehearing and accept ISO-NE's CT proxy proposal, under which the CT proxy price may serve as a safe harbor during all hours, and bids that exceed the CT proxy safe harbor will be subject to the mitigation review that applies to transmission-constrained periods. We believe ISO-NE's proposal for DCAs is a reasonable mitigation measure that may reduce the need for RMR contracts and encourage demand response and new entry.

20. However, we remain concerned that obtaining a scarcity price under this mechanism may give generators an incentive to depart from a competitive marginal cost bidding strategy. As a result, this mechanism may result in scarcity prices being paid when there is no scarcity, but fail to result in scarcity pricing when scarcity truly does exist. Therefore, we will require ISO-NE to consider, as an alternative to the CT proxy proposal which we approve here, a scarcity premium proposal: namely, using the CT proxy to establish a scarcity premium that would automatically be added to LMPs in a DCA regardless of what generators bid whenever a need for scarcity pricing arose. Under this scarcity premium proposal, at a minimum, scarcity pricing would be required whenever there was a reserve shortage. However, ISO-NE could define other tight demand conditions that may also justify the payment of a scarcity premium. Once ISO-NE defined the conditions under which the payment of a scarcity premium would be appropriate and set forth a CT proxy price that would serve as a scarcity price during scarcity periods, a premium would automatically be added to LMP to make LMP equivalent to the CT proxy price during those periods. Under this alternative, the CT proxy price would likely be higher than under ISO-NE's proposed scheme, since it would be designed to recover costs over fewer hours. Generators, however, would be assured of receiving that premium at those times, so they would have no incentive to depart from a competitive bidding strategy, and could submit competitive bids at all times, and customers would be assured that they would pay scarcity prices only during times of scarcity. We believe that this approach would better permit scarcity pricing in DCAs when it was needed, without distorting competitive marginal cost bidding incentives.

21. We thus rule that ISO-NE may implement its proposed mitigation mechanism, using the CT proxy price as a safe harbor for all generators in DCAs at all times.[9] However, we will require ISO-NE to file with us, within 90 days, a statement as to the scarcity premium proposal that we have suggested. If ISO-NE agrees that use of a scarcity premium in this way to achieve scarcity pricing in DCAs better meets its goals, without delaying implementation of its new market design, ISO-NE must so state, and must provide a schedule for implementing this alternative. If, on the other hand, ISO-NE believes that the scarcity premium proposal is inferior to ISO-NE's proposed alternative, it must so state, and explain why. In that case, ISO-NE's mechanism which we here approve will stay in force. Finally, if upon reviewing our scarcity premium proposal, ISO-NE believes that it could provide a different option which would more effectively provide for appropriate scarcity pricing, it should provide that, and explain why.

22. We note that ISO-NE and NEPOOL must make an informational filing to allow us to approve (1) what areas are designated as DCAs, and (2) the CT proxy price for each DCA. If ISO-NE ultimately chooses to implement our suggested scarcity premium proposal or to propose a different scarcity pricing proposal, it will also need to make a filing amending Market Rule 1 pursuant to Section 205 or 206 of the Federal Power Act (FPA)[10] at that time.

23. Market monitoring. Connecticut PUC states that the thresholds and mitigation proposed by NEPOOL for generators outside DCAs are insufficient, and would allow for a significant amount of withholding before they are triggered. Connecticut PUC argues for "low or non-existent" thresholds to trigger monitoring. NSTAR asserts that the consultative feature of ISO-NE's proposal (that ISO-NE will consult with a generator which appears to be exercising market power before imposing price mitigation) gives ISO-NE too much discretion not to impose mitigation and shuts other parties out of this process. NSTAR also asserts that the mitigation levels should be subject to a temporal sliding scale (so that the 300 percent level would be applicable for five days within a calendar year, after that it would drop to 200 percent for the next 15 days, and so forth.) NSTAR further argues that the Commission should adopt the New York Independent System Operator's (NYISO's) Automatic Mitigation Procedure (AMP) protocols,[11] or

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[9]NU's request for clarification as to when we would intend the CT proxy price within DCAs to apply is thus moot.

[10]16 U.S.C. §§ 824d and 824e (2000).

[11]See New York Independent System Operator, Inc., 99 FERC ¶ 61,246 (2002).

some other circuit breaker that automatically mitigates prices when certain thresholds are crossed, to ensure protection against market power.

24. In their comments on ISO-NE's and NEPOOL's October 7 compliance filing, PG&E states that ISO-NE's mitigation in unconstrained periods is unjustified, because absent transmission constraints, the $1,000 bid cap provides sufficient protection against the exercise of market power. Edison Mission makes similar arguments, stating that this is an opportunity for ISO-NE to demonstrate that a market using LMP, with adequate supply to meet load, can operate efficiently without bid-based mitigation measures. Edison Mission states that the supply picture has improved and the New England markets are workably competitive, and ISO-NE's argument that anticompetitive behavior will continue is speculative at best. DENA and EPSA in their protests similarly oppose mitigation in unconstrained periods. NECPUC, on the other hand, supports mitigation in unconstrained periods, and suggests that the fact that mitigation has been triggered so rarely under these circumstances could also mean that these mitigation measures are too lax, and stronger measures are required.

25. Commission ruling: The Commission's September 20 Order requested additional support for the application of mitigation measures when dispatching is unaffected by transmission constraints in addition to the $1000 per megawatt hour bid cap. ISO-NE responds that it believes that the mitigation thresholds should be retained in this circumstance. It notes that these threshold levels closely track existing Commission-approved measures for NEPOOL and are similar to those recently authorized for New York.

26. As requested, ISO-NE submitted updated information describing the state of competition in its markets. Although it does not suggest that any single measure of competitiveness is definitive, ISO-NE reports that the Herfindahl-Hirschman Index (HHI) and Residual Supply Index[12] both suggest that its markets are competitive in the majority of hours. The majority of serious market power concerns arise in capacity deficiency periods (OP-4 conditions). However, even outside OP-4, certain suppliers

[12]The HHI, a measure of market concentration, is the sum of the squares of market shares of each supplier. ISO-NE calculates monthly HHIs as the sum of the squares of capacity shares of generation owners. The Residual Supply Index is defined as the ratio of residual supply to total market demand. Residual supply is the generation capacity that remains in the market after subtracting the capacity of a particular bidder. New England's calculations are for the largest bidder. Whenever the Residual Supply Index for a bidder falls below 100 percent, that bidder is unambiguously judged to have market power.

could be pivotal, and ISO-NE identifies approximately 105 hours outside of OP-4 hours during the summer of 2002 when its Residual Supply Index was less than 100 percent, indicating that its markets were vulnerable to anticompetitive conduct.

27. In NEPOOL's unconstrained periods, mitigation measures currently authorized in addition to the $1000/MW-hour bid cap and proposed in Market Rule 1 have never been triggered in the year and a half that they have been in place. ISO-NE argues, however, that this does not mean that such mitigation measures are not needed or have not been useful. It emphasizes that such measures serve as "rules of the road" and promote competitive bidding behavior. It points to the behavior in California markets when apparent non-competitive bidding occurred even when there were no transmission constraints. ISO-NE argues that, even in non-constrained hours, the potential for some suppliers to exercise market power beneath the $1000/MW-hour cap cannot be dismissed, and thus, mitigation measures remain important safeguards for New England's developing markets.

28. The Commission will approve only mitigation measures that address well-defined structural problems in the market. As markets mature, we expect that underlying structural problems causing market power will be resolved, and at that point behavioral mitigation rules can be removed. The New England market has matured significantly over the last few years since ISO-NE began operating the system due to divestiture and competitive entry. Market concentration has fallen to HHI levels under 1000. Mitigation rules for unconstrained areas were not triggered over the last year and a half. The ISO’s request for mitigation authority in unconstrained areas referred to pivotal suppliers that have market power at certain times. However, the ISO did not identify these suppliers or the number of hours in which each individual supplier is pivotal. Nor did the ISO explain how the proposed mitigation targets this structural problem, that is, how the proposal would mitigate only the individual suppliers that are pivotal without targeting other suppliers that are not pivotal. Therefore, we reject this proposal for Level 1 Mitigation without prejudice to a filing that evaluates any remaining structural problems and a proposal that targets only those suppliers that obtain market power as a result of these structural problems. We are accepting the mitigation proposal for periods when transmission constraints cause a unit to be dispatched above the level it would have been dispatched absent the constraint, during which the unit's supply offer will be investigated if it exceeds its corresponding reference price by the lesser of 50 percent or $25.

B. RMR issues

29. CTAG argues that localizing the cost of RMR agreements will cause significant harm to Connecticut's consumers. Specifically, CTAG states that localizing costs will

add tremendously to the price of electricity in Connecticut, raising power costs associated with congestion approximately 17% over the next five years, and that, given the obstacles to development of new generation and transmission capacity in Connecticut, the Commission failed to consider the existence of market power due to the concentration of resources under a single company. CTAG states that localization of RMR costs will reward the existence and exercise of market power by that entity, and that it will unjustly penalize Connecticut customers and hinder the development of retail competition. CTAG asks the Commission to require ISO-NE to carefully scrutinize and validate the fixed and operating costs of any RMR agreement in Connecticut.

30. VPPSA similarly suggests that, to the extent that RMR costs reflect market power and not economic scarcity, the localization of RMR costs will not send appropriate price signals, and that the dilution of signals resulting from pricing at a regional level will mute the relationship of price signals and cost causation.

31. NSTAR states that RMR agreements should not be used to support uneconomic generation resources except where such resources are necessary for reliability. NSTAR argues that, since resources with RMR agreements are essentially leasing their units from the pool rather than owning them, the pool should have full rights to control the unit, including bidding conduct, so long as the owner is fully compensated according to the agreement. Additionally, NSTAR would limit the availability of RMR agreements only to the minimum number of MWs needed for reliability, would not allow generators to switch between market operations and RMR agreements. It would also have all RMR agreements subject to review by NEPOOL Participants before filing with the Commission, and states that the Commission erred in not specifying that RMR Agreements are ineffective until approved by the Commission.

32. Commission response: The joint ISO-NE and NEPOOL SMD filing offered two alternatives, as developed by the participants in the stakeholder process, to allocate the RMR fixed costs. We deny CTAG's and VPPSA's request for rehearing as to the localization of RMR costs. In the September 20 Order, the Commission found Option 1, which allocates RMR fixed costs to the local reliability area, to be the only option consistent with the underlying tenets of LMP market design, and CTAG and VPPSA have presented no new arguments to make us reconsider this ruling. Without proper market price signals, no long-term solution to the plight of load pockets such as Southwest Connecticut will be forthcoming. We find that Connecticut customers will suffer greater damages from the continuing lack of adequate generation and transmission

resources than from the harms that CTAG lists.[13] With respect to the concentration of ownership of generation resources, the Commission approved in both the September 20 Order and in this order a comprehensive market power monitoring and mitigation proposal to detect and address the exercise of market power in just such situations as CTAG describes.

33. CTAG, VPPSA and NSTAR seek to limit ISO-NE's ability to negotiate RMR agreements, and NSTAR would prevent resources from switching between RMR and market-based operation. The Commission has determined that ISO-NE has the authority to negotiate such agreements as are needed for system reliability. NSTAR again attempts to broaden the scope of the RMR agreements, a position rejected in the September 20 Order. The conditions under which the ISO may enter into RMR agreements are of necessity flexible in order to meet the changing demands of the markets, although we will expect ISO-NE to exercise vigilance to ensure that only those units that are needed to ensure reliability receive RMR contracts, and that those contracts will not be in effect indefinitely, but will be limited to the period during which the units are needed for reliability. These agreements will be filed with the Commission in accordance with the Commission's rules and regulations and will be effective on the date approved by the Commission. The filing of these agreements with the Commission will give any interested party an opportunity to comment on them. No new arguments are found in these requests for rehearing and the Commission therefore denies them.

C. Transitional issues relating to Connecticut

34. CTAG and Connecticut PUC argue on rehearing that adopting LMP in New England would substantially increase costs to consumers in Connecticut, especially Southwest Connecticut, due to transmission constraints in that area. Connecticut PUC estimates, based on ISO-NE's 2002 Regional Transmission Expansion Plan, that LMP would raise Connecticut's costs by \$125-\$375 million per year. To reduce the adverse impact of LMP on Connecticut consumers, CTAG and Connecticut PUC request several transition mechanisms, such as delaying LMP in Connecticut or socializing the costs of local reliability and transmission upgrades into Connecticut.

35. Commission response: we will deny the request to delay the implementation of LMP in New England pending a resolution to Connecticut's transmission constraints. Delaying LMP would delay the benefits to New England of sending more accurate price

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[13]The Commission agrees with CTAG's assertion that proper price signals alone will not attract new generation and transmission capacity. However, other obstacles to the development of new resources are simply beyond the jurisdiction of the Commission.

signals about the costs of delivering electricity to the various locations in that area. We expect that more accurate price signals will encourage more efficient supply and demand decisions in both the short and long run.

36. However, we are sympathetic to the concerns of CTAG and Connecticut PUC regarding the effects of LMP on Connecticut consumers. As a matter of equity, it would be reasonable to adopt measures that could moderate the financial impact of LMP on Connecticut consumers without blunting LMP price signals. One measure would be to reduce congestion by building a defined set of transmission upgrades into Southwest Connecticut, identified at the start of the implementation of LMP, and to assign a portion of the upgrade costs to other New England customers. Such a mechanism could allow the economic benefits of LMP to be shared more widely through a defined and limited assignment of transmission upgrade costs that would moderate the increase in LMP prices in Connecticut.[14] To aid in the transition to LMP, we encourage ISO-NE to work with New England market participants to identify and construct a defined set of transmission upgrades into Southwest Connecticut, and we commit to allowing the costs of such upgrades that are placed in service within 5 years from the date of this order to be spread among customers throughout New England.[15] We note this is consistent with our ruling infra that the costs of demand response will also be spread system-wide.

D. Demand response issues

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[14]Indeed, the Commission approved a similar mechanism for the customers in Northeastern Massachusetts as part of a compromise package to implement LMP. Specifically, NEPOOL proposed to socialize for an interim period the costs of a series of transmission upgrades into the Northeastern Massachusetts (NEMA) area, which the Commission has approved in a February 15, 2002 order. These upgrades are expansions not related to generation interconnection in NEMA that will be in service by June 30, 2004. These transmission upgrades would moderate the price increases that LMP would bring to customers in the NEMA area. See 98 FERC ¶ 61,173 at PP 49 - 62 (2002). At the time that the Commission approved the mechanism, the Commission noted that congestion costs in New England were socialized, and thus, relieving congestion through the NEMA upgrades would benefit all participants.

[15]This rate treatment will also apply to those upgrades that are already planned or under construction as of the date of this order, such as the transmission upgrades in ISO-NE’s 2002 Transmission Expansion Plan to address problems in Southwest Connecticut, as to which Phase 1 is planned to be completed in 2004 and Phase 2 is planned to be completed in 2006.

37. Under Market Rule 1, customers serving load would be permitted to submit price bids that indicate the maximum price they are willing to pay for energy.[16] When the energy price exceeds a customer's price bid for an amount of load, that amount of the customer's load would not be scheduled in the day-ahead market and the customer would avoid paying the day-ahead energy price for that load. The financial benefit to the customer in this instance would the be avoidance of paying the energy price.

38. The September 20 Order accepted a Load Response Program, which would offer an additional financial benefit to customers for reducing their loads – a payment for the amount of the reduced load. This payment would vary among the different components of the Load Response program. For the Day-Ahead Demand Response Program component, the payment would equal the applicable locational day-ahead energy price. Customers could submit price bids to participate in the Day-Ahead Demand Response Program component, which would indicate the minimum price that the customer requires to be paid in order to reduce its load. The September 20 Order accepted ISO-NE's and NEPOOL's proposal to place a floor of $50/MWH and a ceiling of $500/MWH on the price bids submitted by customers into the Day-Ahead Demand Response Program. A customer whose bid is accepted would be paid the applicable energy price, even if the price exceeded its bid. ISO-NE states in its July 15 filing that the minimum bid of $50 would ensure that demand side resources that were scheduled to be out of service will not be able to obtain credit and payment for a reduction. It also states that, since resources in the Demand Response Program would be eligible for ICAP payments, the maximum bid of $500 would ensure that the resource might be dispatched in the Day-Ahead Energy Market at least during times of high loads. For the Real-Time Price Response Program component, the payment for reducing load would be the higher of the applicable real-time zonal energy price or $100/MWH. However, payments under the Real-Time Price Response Program would be offered only when ISO-NE forecasts in advance that the zonal energy price will equal or exceed $100/MWH.

39. NICC alleges that the Commission erred by adopting ISO-NE's proposal to cap bids in the Day-Ahead Demand Response Program at $500/MWH, while allowing generators in the day-ahead market to bid up to $1,000/MWH. NICC proposes that both demand resource and generator bid caps must be equal in the Day-Ahead Market. According to NICC, the result of the Commission's approval of a bid disparity is that demand resources bidding into the Day-Ahead Demand Response Program cannot submit bids higher than $500/MWh, regardless of the costs that the demand resources may incur to provide the demand response. Generators may submit bids in excess of this amount, which likely exceeds the marginal and opportunity costs of most generators.

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[16]See Sec. 1.10.1A(a) of Market Rule 1.

NICC claims that the service that demand resources provide is identical to the service being provided by generators, and the Commission is thus treating generators and demand resources unequally.

40. NXEGEN seeks rehearing on two issues. First, it asks the Commission to eliminate the floors on curtailment bids in the Day-Ahead and Real-Time Demand Response Programs, arguing that restricting curtailment bids to price levels that occur in a limited number of hours will impede the proactive utilization of demand resources and render most investments in demand response technology uneconomic. NXEGEN further argues that neither Demand Bids nor Decrement Bids will allow demand resources to interrupt their load at a lower price than the demand side management plan minimums.[17]

41. Second, NXEGEN asks the Commission to eliminate the requirement that curtailments be verified only through interval meters, and provide for verification by comparable alternative procedures. NXEGEN claims this requirement creates an artificial barrier to the development of alternative metering and curtailment technology, and also to the growth in demand resources. It also claims that there are alternative technologies that produce data comparable to those obtained from interval meters deployed by electric distribution companies.

42. Connecticut PUC takes issue with the Commission's approval of allocating costs of a portion of the Load Response Program to applicable load obligation on a load zone basis. Connecticut PUC states that in the Real-Time Demand Response Program there are reliability benefits accruing to the entire control area that cannot be disaggregated by zone, and thus, the costs associated with the Real-Time Demand Response Program should be allocated on a system-wide basis.

43. Connecticut PUC further urges the Commission to allow demand resources that participate in the Day-Ahead Demand Response Program whose offer is not accepted in the day-ahead energy market to be able to participate in the Real-Time Demand Response Program as well as the Real-Time Price Response Program. Connecticut PUC also believes that the compensation in the Real-Time Demand Response Program is too low and will not elicit robust customer participation and that limited participation in load response in Southwest Connecticut could pose reliability risks in that subregion. Connecticut PUC urges the Commission to redraft its approval of the Real-Time Demand Response Program to allow ISO-NE the flexibility to offer higher compensation to

[17]NXEGEN makes similar arguments in its comments submitted in response to the Commission's October 9 panel discussions.

participants -- up to the limit offered by the NYISO -- without seeking further Commission approval.

44. Commission Response: we will deny the request by NXEGEN to remove the $50/MWH bid floor in the Day-Ahead Demand Response Program and the $100/MWH minimum price for triggering the Real-Time Price Response Program. 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. Nor would the minimum triggering price associated with the Price Response Program prevent customers from voluntarily reducing their energy purchases in the real-time energy market in response to energy prices below $100/MWH. We have some concern about the rationale for establishing a bid floor ($50/MWH) for the Day-Ahead Demand Response Program that is different from the minimum triggering price ($100/MWH) in the Real-Time Price Response Program. However, since these programs are temporary and we are requiring ISO-NE to file other demand response programs as discussed below, we will not require a change in the minimum bid or minimum triggering price at this time.

45. We will grant NICC's request to raise the bid ceiling from $500/MWH to $1,000/MWH, the same bid ceiling that applies to suppliers in the energy market in the Day-Ahead Demand Response Program. We believe supply and demand resources should be treated consistently with respect to the bid ceilings. It is valuable to encourage load response during times of increasing scarcity because of its potential to improve reliability and reduce price volatility. The ceiling proposed by ISO-NE and NEPOOL would unnecessarily restrict participation in these programs during periods of scarcity. Moreover, since there is very little demand response in the market currently, we believe it would be in the public interest to provide additional incentives for demand response for an interim period in order to encourage customers to reduce demand.

46. The Commission shares NXEGEN's concerns for the development of new metering technologies. Therefore, we grant NXEGEN's request for rehearing and direct NEPOOL and ISO-NE to work with interested parties and experts at the Department of Energy, the Electric Power Research Institute and elsewhere to develop performance-based, rather than technology-based, standards for determining energy

usage. We require ISO-NE to engage in such consultations, develop performance-based standards, place those standards into the appropriate manual or manuals, and make an informational filing at this Commission within 180 days of the date of this order. As we underscored in the SMD NOPR, measures that facilitate a robust demand response are essential to the success of competitive wholesale markets. As markets mature in other regions, the Commission will insist on similar measures in all regional markets.

47. We note that the New England parties have been participating in the New England Demand Response Initiative (NEDRI) effort to develop demand response programs for New England. In order to get a broad, effective set of demand response programs into place by summer 2003, we will require NEPOOL to make a filing revising its demand response programs to reflect the results of the NEDRI process by February 1, 2003. This filing will allow the Commission to fully consider the NEDRI proposal. If NEPOOL cannot obtain a majority of votes to make this filing, we require ISO-NE to make the filing, noting the fact that NEPOOL could not obtain the necessary majority. Parties will then be permitted to raise their concerns directly before the Commission.

48. The Commission recognizes the validity of Connecticut PUC's request that costs associated with the Real-Time Demand Response Program should be allocated on a system-wide basis, and its request to allow demand resources that participate in the Day-Ahead Demand Response Program whose offer is not accepted in the day-ahead market to be able to participate in the Real-Time Demand Response Program as well the Real-Time Price Response Program. As to allocating the costs associated with the Real-Time Demand Response Program system-wide, we will allow such allocation as an initial matter, in order to encourage the development of demand response programs. As to allowing demand resources to participate in additional programs, this is an issue that we expect NEPOOL or ISO-NE to address when it makes its filing regarding the NEDRI proposals for demand response.[18] As a long-term matter, the allocation of DR costs should parallel the recovery of transmission costs.

49. We deny Connecticut PUC's request that we allow ISO-NE the flexibility to offer higher compensation to participants in the Real-Time Demand Response Program without seeking Commission approval. If Connecticut PUC believes it can support the link between compensation and level of participation on this issue, we urge Connecticut

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[18]Moreover, the Commission disfavors raising entirely new issues for the first time in a rehearing petition. See California Independent System Operator Corporation, 101 FERC ¶ 61,219 at P 41 (2002); San Diego Gas & Electric Company, 99 FERC ¶ 61,160 at 61,649 (2002); Baltimore Gas and Electric Company, 92 FERC ¶ 61,043 at 61,114 (2000).

PUC to use the New England stakeholder process to develop a proposal that can be provided to the Commission for approval along with the filing that will be made on February 1 that reflects the NEDRI initiative. Any such proposal should provide for charges allocated on a local (zonal) basis only, and not require the uplift of demand response prices to all New England participants.

II. Cost Allocation Issues

E. Mechanism to allocate transmission upgrade costs

50. Several parties seek clarification or rehearing of the question of what mechanism NEPOOL and ISO-NE will use to allocate the costs of new transmission upgrades to the system. ISO-NE and NEPOOL jointly state that this issue is not yet ripe for determination, and ask for clarification that the Commission has not foreclosed the use of a mechanism under which the costs of PTF[19] upgrades are socialized across the pool, and the costs of non-PTF upgrades are allocated to those specific parties who benefit. NEPOOL and ISO-NE state that they have not developed an alternative cost allocation mechanism, and note that there is still disagreement between those parties who wish to socialize upgrade costs, and parties who favor other approaches. ISO-NE states that its Board recently voted to institute a stakeholder process that would enable the NEPOOL participants, state regulators, and other interested parties to work together to resolve this question. ISO-NE also states, in its separate filing, that whatever new cost allocation mechanism is developed should only apply prospectively, so as to avoid disruption to projects already in process. Connecticut PUC, United Illuminating, NU, National Grid and MMWEC also seek rehearing or clarification on this matter. In its protest to NEPOOL's October 21 compliance filing, Central Maine notes that it opposes any move to socialize the costs of upgrades.

51. Commission response: the Commission will grant rehearing, and states that, since NEPOOL and its stakeholders are about to address this problem, we will not at this time foreclose any cost allocation mechanism. While we have allowed occasional deviations

[19]"Pool Transmission Facilities" or "PTF" are the pool transmission facilities defined in Section 15.1 of the Agreement, and any other new transmission facilities which the Reliability Committee determines, in accordance with criteria approved by the Participants Committee and subject to review by the ISO, should be included in PTF.

from this principle (such as the costs of the "NEMA and quick fix" upgrades to ease constraints northeastern Massachusetts, which we have permitted to be socialized across the pool, and the similar treatment we propose below for Connecticut), since 2000 we have been urging New England to develop an objective, non-discriminatory default mechanism to allocate the costs of upgrades which are not clearly either beneficial solely to a discrete party or group of parties or beneficial to the entire pool.[20] We urge the NEPOOL stakeholders to work together to develop a consensus on such a mechanism, guided by the above principles. In order to avoid possible disruption to current projects, the mechanism developed through this stakeholder process will become effective only prospectively.

F. QUAs

52. Among the entities that are allocated ARRs are entities that pay for transmission upgrades that increase the transfer capability on the NEPOOL system (Qualified Upgrade Awards or QUAs). We stated in the September 20 Order that "ISO-NE's proposal lacks necessary details. It is imperative that ISO-NE be transparent in all of its calculation, procedures, and review processes."[21]

53. Duke Energy North America, LLC (DENA) requests clarification with regard to the process for QUA allocation. DENA states that it interprets the September 20 Order to have agreed with DENA's concerns, not only that the procedures employed by ISO-NE must be transparent, but the calculations must be based on an actual incremental transfer value associated with the new transmission upgrades.

54. Commission response: we grant DENA's request for clarification. ISO-NE must calculate the MW value of the increase in transfer capability created by a transmission upgrade and the amount of ARRs awarded should be based on this calculation.

G. Allocation of Auction Revenue Rights

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[20] ISO New England et al., 95 FERC ¶ 61,384 at 62,436 (2001) (footnotes omitted).

[21] September 20 Order at P 84.

55. In September 20 Order, the Commission directed ISO-NE and NEPOOL to remove the provision of Market Rule 1 allocating ARRs (Auction Revenue Rights)[22] to "Congestion Paying Entities."[23] In their compliance report filed on October 21, 2002, ISO-NE and NEPOOL removed the provision allocating ARRs to "Congestion Paying Entities" and replaced it with a provision allocating ARRs to "Congestion Paying LSEs." The term "Congestion Paying LSE" is defined, for the purpose of the allocation of FTR Auction Revenues as

> a Participant or Non-Participant that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service or Long-Term Firm Point-to-Point Transmission Service under the NEPOOL Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with NEPOOL System Rules, in which case the Congestion Paying LSE shall be the Participant supply the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the NEPOOL System Rules.[24]

56. ISO-NE and NEPOOL state that the allocation of ARRs to Congestion Paying LSEs, as defined above, would support retail access by allowing ARRs to "follow the load" as loads change retail suppliers over time.

57. Finally, DENA also asks the Commission to find that the contribution made by its Casco Bay affiliate to upgrade Central Maine's system to accommodate power flows on the Maine Electric Power Company (MEPCO) transmission line should entitle Casco Bay to ARRs. DENA asserts that, although those parties contributing to the MEPCO line are not NEPOOL Transmission Customers, and so would not receive ARRs, the circumstances surrounding the operation and function of the MEPCO line make it unique, and warrant treating parties who contributed to the MEPCO line as if they were NEPOOL Transmission Customers and awarding them ARRs.

58. Commission response: we will accept the proposal of ISO-NE and NEPOOL to allocate ARRs to Congestion Paying LSEs as defined above because, based on our

[22]ARRs are rights to receive FTR Auction Revenues from the sale of FTRs.

[23]September 20 Order at P 85.

[24]October 21 compliance filing, transmittal letter at 6.

understanding as discussed below, the proposal would allow load to receive the benefits of ARRs.

59. In the September 20 Order, we expressed a preference for allocating ARRs to those who pay embedded cost transmission charges. We continue to believe that loads should receive the benefits of the transmission system for which they pay, by way of the embedded cost transmission charge. ARRs are one way of obtaining such benefits.

60. One type of Congestion Paying LSE is an entity that is a Transmission Customer that pays for Regional Network Service or Long-Term Firm Point-to-Point Transmission Service, and that is responsible for paying Congestion Costs. It is our understanding that the entities responsible for paying Congestion Costs, as discussed in the above definition, are those that either (1) purchase energy in ISO-NE's spot energy market, or (2) pay the applicable transmission congestion charge for moving bilaterally-contracted energy from the generation source to the load. Further, it is our understanding that each entity serving energy to load would pay congestion costs, either by virtue of purchasing energy in ISO-NE's spot market or by paying transmission congestion charges for transmission service to move bilaterally-contracted energy to the load. Thus, it is our understanding that every Transmission Customer that pays for Regional Network Service or Long-Term Firm Point-to-Point Transmission Service and that serves energy to load is a Congestion Paying LSE. Based on our understanding, we find it reasonable to allocate ARRs to this type of Congestion Paying LSE, since such an LSE pays an embedded cost charge for Regional Network Service or Long-Term Firm Point-to-Point Service and since all such LSEs would be eligible to receive ARRs. We will require ISO-NE to file a statement, within 30 days of the date of this order, explaining whether our understanding is correct. To the extent that our understanding is incorrect, the statement must explain any errors in our understanding.

61. The other type of Congestion Paying LSE would exist in a state allowing competition among retail service providers. This latter type is an entity that takes over, from a Transmission Customer that pays for Regional Network Service or Long-Term Firm Point-to-Point Service, the responsibility to supply energy to the loads formerly served by the Transmission Customer. This latter type of Congestion Paying LSE would not necessarily pay an embedded cost transmission charge. However, we find it reasonable to allocate ARRs to this latter type of Congestion Paying LSE (rather than to the Transmission Customer who pays the embedded cost transmission charge), for the following reason.

62. We expect that the Transmission Customer that pays the transmission embedded cost charge would flow this charge through to its retail loads. Under ISO-NE's proposal,

the retail service provider that wins the competition to supply energy to the load would be allocated ARRs. We would expect that competition among alternative retail service providers would result in the benefits of the ARRs being passed on to the load that it services. Thus, we would expect that retail loads would ultimately both bear the embedded transmission costs and receive the financial benefits of the ARR allocation.

63. On rehearing, ISO-NE and NEPOOL, as well as Constellation and NU, seek clarification and/or rehearing that the September 20 Order's requirement that "Congestion Paying Entities" be removed from the allocation of ARRs does not mean that entities serving the load of Participants paying for long-term firm transmission service be prohibited from receiving ARRs, so long as long-term firm transmission customers and all Excepted Transactions are also allocated their share of ARRs. We grant the requested clarification.

64. Finally, as to the issue that DENA raises regarding whether Casco Bay should receive ARRs because of its contribution to the MEPCO line, the Commission denies rehearing, and will decline to address this issue here. DENA itself states that the circumstances surrounding the MEPCO line are unique, and it does not appear that deciding the specific question of the MEPCO line is necessary for us to evaluate ISO-NE's proposal for allocating ARRs. Therefore, we find it inappropriate to decide this issue in the context of a broad generic proceeding such as this one. DENA and Casco Bay are free to seek relief by filing a complaint or by participating in the stakeholder process that NEPOOL will be conducting as to the allocation of the costs of transmission upgrades.

H. Excepted transactions and physical rights

65. In its protest to NEPOOL's and ISO-NE's original filing, Central Vermont stated that the tariff as filed abrogated the rights of parties to Excepted Transactions.[25] We stated in the September 20 Order that "the Commission's policy is generally not to require abrogation of contract rights, and to allow parties to retain their bargained-for benefits," and we therefore required NEPOOL and ISO-NE to remove the following sentence from Appendix C, 2.1: "Excepted Transactions will not be permitted to use their existing contract rights for physical scheduling of a transaction."[26]

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[25]Excepted Transactions are those transmission agreements in effect on November 1, 1996 specified in Section 25 and Attachments G, G-1, and G-2 of NEPOOL's tariff.

[26]September 20 Order at P 87.

66. NEPOOL and ISO-NE did so in their October 21 compliance filing, and replaced it with the following:

> The party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction which is an External Transaction will retain its existing contract rights for physical scheduling of such transaction until such party elects to be allocated ARRs under this Section 2. Once the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction which is an External Transaction elects to be allocated ARRs, the party (i) will not be able to revert back to using their contract rights for physical scheduling; and (ii) may request to be allocated ARRs, prior to each FTR Auction[.]

67. In protests to the October 21 compliance filing, Central Vermont and MASSPOWER state that the proposed replacement language is an inappropriate submission of new tariff language in a compliance filing, and should be proposed in a new Section 205 filing. Central Vermont further argues that there are other Excepted Transactions affected by Market Rule 1, and requests that ISO-NE include a provision that recognizes the Commission's protection of all contract rights of all Excepted Transactions.

68. NU states in its request for rehearing of the September 20 Order that in this case the reasons for removing the physical rights outweigh the benefits of protecting existing contract rights. NU notes that NEPOOL has recognized and compensated for these physical rights by giving preferential treatment to external Excepted Transactions in the allocation of ARRs. NU acknowledges that the findings of the September 20 Order in this regard could be accepted as transitional because these are pre-existing agreements, but NU is concerned that giving physical rights to holders of financial rights could impair the free trading of financial instruments and could limit access to transmission by non-holders of financial rights during times of constraint, regardless of a party's willingness to pay congestion costs.

69. In its comments on NEPOOL's October 21 compliance filing, however, NU states that NEPOOL has complied with the Commission's order by providing that parties to Excepted Transactions may continue to exercise physical rights, but adds that NEPOOL has also provided that, should those parties convert their physical rights to financial

rights, they may not subsequently revert from financial rights back to physical rights. On this basis, NU supports NEPOOL's revision as in compliance with the Order.

70. MASSPOWER asks the Commission to clarify that parties to Excepted Transactions may elect to retain their existing physical transmission rights when NE-SMD goes into effect. MASSPOWER goes on to state that the rates, terms and conditions of Excepted Transactions are governed by the terms of the contracts, and not by the NEPOOL tariff. These transactions predate Order No. 888 and, in approving the NEPOOL rate settlement, the Commission allowed the parties to these transactions to keep their bargained-for benefits. MASSPOWER states that this could only mean that neither the contract holder nor the parties taking delivery under an existing firm transmission service would be required to pay a delivery charge in excess of the stated price, e.g., congestion costs. Further, MASSPOWER states that it was the Commission's intent, when the Commission ordered the removal of the sentence prohibiting "use of existing contract rights for physical scheduling of a transaction," to allow all pre-Order No. 888 contract customers to retain their firm transmission rights.

71. Central Vermont supports MASSPOWER's motion, but states that it does not go far enough in support of pre-Order No. 888 contracts. Central Vermont's position is based on its understanding of Footnote 53 in the September 20 Order, which stated that "an Excepted Transaction is a transmission contract that existed prior to Order No. 888."[27] Central Vermont states that, because of this footnote, all pre-Order 888 contracts should be treated as external Excepted Transactions with respect to physical scheduling rights. Central Vermont thus would expand this pool of protected contracts to include those using non-PTF facilities. Central Vermont also states that the protected contract rights include not only scheduling and curtailment priority but also physical delivery at a fixed price.

72. NEPOOL and ISO-NE filed a joint answer on this issue stating that rather than trying to preserve existing rights, MASSPOWER and Central Vermont are seeking to expand the rights of Excepted Transactions under the NEPOOL tariff. NEPOOL and ISO-NE argue that Excepted Transactions internal to NEPOOL do not have the physical scheduling rights claimed by MASSPOWER and Central Vermont. NEPOOL and ISO-NE state that, prior to the NEPOOL tariff's inception in 1997, transactions internal to NEPOOL were scheduled on an economic basis rather than on the basis of physical scheduling priorities. They state that external Excepted Transactions do currently have a scheduling priority for imports into NEPOOL under the tariff. But, this scheduling priority does not apply to internal transactions. ISO-NE states that there was no change

[27]September 20 Order at P 81 n. 53.

in scheduling when the NEPOOL tariff went into effect, and that MASSPOWER will have the same rights under Market Rule 1 that it has under Section 25 of the current NEPOOL tariff. Further, ISO-NE states that, since the inception of the NEPOOL tariff, MASSPOWER, Central Vermont and other parties to Excepted Transactions were not exempted under the Tariff from paying congestion costs because of their status as Excepted Transactions.

73. National Grid states, in its answer to MASSPOWER's answer, that under the current NEPOOL tariff, MASSPOWER's Excepted Transaction has the same scheduling priority for internal transactions as firm service provided under the NEPOOL tariff. National Grid states that, by arguing that it should be able to avoid the payment of congestion costs, MASSPOWER is seeking a higher priority than is available to firm customers under the NEPOOL tariff.

74. Commission response: given that NU's concerns in its rehearing petition appear to have been addressed in NEPOOL's October 21 compliance filing, we will dismiss NU's request for rehearing in this regard as moot.

75. As to Central Vermont's and MASSPOWER's protest regarding filing new tariff language, we will require ISO-NE to delete such language from the tariff as an inappropriate submission in a compliance filing.

76. We will deny MASSPOWER's request for clarification and rehearing regarding the scheduling priority of Internal Transactions and Central Vermont's protest. Our intent in the September 20 Order was to maintain the existing rights held by Excepted Transactions, not to expand those rights. The language we required to be removed in the September 20 order appeared to reduce the rights of Excepted Transactions. However, we agree with NEPOOL and ISO-NE and National Grid that the changes that Central Vermont and MASSPOWER seek in their protests would go beyond maintaining their existing rights. The current NEPOOL tariff defines the rights of Excepted Transactions. Under the current tariff, these customers do not have physical scheduling rights for internal transactions and Excepted Transactions do not have higher priorities for scheduling internal transactions than firm service provide under the NEPOOL tariff. The requested changes would thus expand the rights that MASSPOWER and Central Vermont currently have under the currently effective NEPOOL tariff, and we will therefore not require those changes.[28]

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[28]We also reject Central Vermont's claim that in Footnote 53 of our September 20 order, we intended to expand the class of excepted contracts beyond those specifically

(continued...)

III. Technical Issues

I. ICAP issues

77. NE-SMD retains ISO-NE's Installed Capability (ICAP) requirement, under which each load serving entity (LSE) must maintain a specified amount of capacity at all times, and must pay a deficiency charge if it fails to do so.[29] NEPOOL and ISO-NE proposed to allocate the ICAP deficiency revenue to all participants. In the September 20 Order, we rejected this proposed allocation method, stating that distributing a portion of the revenues to deficient participants would not send the correct signal to these participants. We therefore directed NEPOOL and ISO-NE to revise Market Rule 1 so that participants that are deficient in UCAP do not receive any of the revenues generated by applying the deficiency charge.[30]

78. In their October 21 compliance filing, NEPOOL and ISO-NE modified Section 8.5.1(c) of Market Rule 1. This modification proposes to allocate deficiency revenues collected by ISO-NE to all participants with UCAP obligations that are not deficient going into the UCAP deficiency auction, and to all participants with a surplus going into the deficiency auction. NEPOOL and ISO-NE state that this method is virtually identical to the current mechanism and reference the order in which we accepted the current allocation method.[31]

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[28](...continued)
identified in NEPOOL's Tariff as Excepted Transactions. That was not our intent. The list of pre-Order No. 888 contracts treated as Excepted Transactions was determined when the NEPOOL tariff went into effect in 1997. It was not our intent to expand that list because of the adoption of NE-SMD.

[29]NE-SMD also adopted the Unforced Capacity (UCAP) standard used by PJM and NYISO which adjusts the capacity rating of generating units to account for forced outage performance.

[30]September 20 Order at P 98.

[31]ISO New England, Inc., 96 FERC ¶ 61,234 at 61,945 (2001). In this order we accepted the method currently in place that allocates revenues to participants that covered their obligations and as well as to those with a surplus, and noted that the method was consistent with that recently approved for PJM.

79. Connecticut PUC requests rehearing, asking the Commission to limit the proposed ICAP regime to be in effect for an interim period until the final rule is issued in the Commission's generic SMD proceeding,[32] when it can be replaced with a better method for ensuring generation adequacy. NRG requests rehearing, asking the Commission to require NEPOOL and ISO-NE to implement a locational ICAP mechanism no later than June 30, 2003. NRG argues that a date certain to implement a locational mechanism is needed to ensure that generators with marginal units needed for reliability purposes will not be required to absorb significant losses in providing these services indefinitely into the future. NRG cites the locational ICAP mechanism used in NYISO and the DCAs in the NE-SMD as illustrating that it would not be difficult for NEPOOL and ISO-NE to implement a locational ICAP.[33]

80. Commission response: The issues raised in these rehearing requests were also raised in the protests to the filing. Neither Connecticut PUC nor NRG raise any additional facts that were not considered in the September 20 Order.[34] We do not believe that it would be prudent to have a resource adequacy mechanism in place with an expiration date that could result in the resurrection of the current less effective mechanism. We decided to take the approach that NEPOOL and ISO-NE could build upon this proposal; and therefore, directed NEPOOL and ISO-NE to develop their proposal further to include additional features (including a locational mechanism), and directed also that the resource adequacy mechanism should comply with the final SMD rule.[35] Additionally, as NRG acknowledges, the RMR provisions in the NE-SMD will provide a mechanism by which these generators may recover costs until a locational ICAP mechanism is developed in the future. On this basis we deny rehearing, and accept the modifications as proposed in the October 21, 2002 Compliance filing.

81. NRG asks for clarification that progress reports required by Ordering Paragraph D include the progress in implementing the locational ICAP mechanism. Paragraph D of the September 20 Order requires NEPOOL and/or ISO-NE to make progress reports every 90 days as to their progress in implementing the market design reforms discussed in the order. Since the order requires NEPOOL and ISO-NE to develop a locational

[32]See Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 100 FERC ¶ 61,138 (2002) (SMD NOPR).

[33]Petition for Rehearing and Clarification at pp 6 - 7.

[34]September 20 Order at P 99.

[35]September 20 Order at P 97.

mechanism, we expect that the progress in meeting this objective, as well as other ICAP objectives such as partial delisting of resources, will be included in the progress reports. We therefore grant this clarification.

J. Zonal/nodal issues

82. NSTAR argues that the Commission erred in granting approval of three separate zones in Massachusetts for the purposes of applying LMP prices. NSTAR states that no empirical evidence exists supporting this arrangement and further argues that other states that currently experience more congestion – namely, Connecticut – will not be subdivided into separate zones. Finally, NSTAR contends that the 18-month implementation schedule is overly aggressive. NU filed a response to NSTAR's comments regarding the Massachusetts zones, arguing that it is inappropriate to raise this objection for the first time in the context of a rehearing request and that NSTAR should have made this argument in its comments to the NE-SMD proposal. NU states that the zones proposed in the SMD filing mirror NEPOOL's already-established reliability regions, parties have entered into contracts which rely on the proposed zones remaining in place, and NSTAR provides no compelling or substantive reasons for altering the proposed zones.

83. NICC asks the Commission to clarify that, where feasible and non-controversial, customers should have the opportunity to see and pay nodal prices. NICC asserts that for many industrial customers load mapping is complete, as their interconnection points serve as pricing nodes. Moreover, NICC states that no party to the proceeding has insisted that nodal pricing implementation be an "'all-or-nothing'" process and that there is reason to believe that the definition of nodes should proceed from high-voltage to lower voltages.

84. NICC further asks the Commission to clarify that: (1) load must have the option to pay nodal prices no later than 18 months after the issuance of the September 20 Order; (2) ISO-NE should file reports with the Commission at least every 90 days in order to update the progress of nodal pricing implementation; and (3) the option to see and pay nodal prices must be available to customers as soon as the market is technologically ready to permit nodal price transactions. NICC also states that the Commission should explicitly direct ISO-NE and NEPOOL to have nodal pricing available as soon as possible, and that this explicit direction is required as NICC is skeptical of ISO-NE's and NEPOOL's ability to achieve full compliance within the initial time-frame. NICC argues that requiring ISO-NE and NEPOOL to file status reports every 90 days regarding nodal pricing implementation would "more directly hold ISO-NE accountable for prompt

implementation of a nodal pricing option for load." NICC also urges the Commission to require that the file an implementation plan within 30 days of the September 20 Order.

85. Commission response: the Commission denies NSTAR's rehearing request in this matter. The Commission finds that defining zones based on already-established geographic boundaries presents the most practical solution to defining zones. As well, the Commission agrees with NU in regard to the timing of NSTAR's opposition; NSTAR was afforded ample time to raise the issue in its initial comments yet failed to do so.

86. Concerning NICC's requests for clarification, the Commission reiterates its position from an earlier order, which directed ISO-NE to "give each load a choice regarding whether to pay nodal prices or zonal prices."[36] The Commission agrees with NICC's statement that the nodal pricing option must be available to customers who wish to use nodal pricing. However, the Commission recognizes that other parties in New England – namely distribution companies in need of data and metering infrastructure modifications – face technical obstacles in their efforts to implement nodal pricing. The Commission directs ISO-NE and NEPOOL to offer nodal pricing to customers where it is technologically feasible to do so.

87. In response to NICC's second request for clarification regarding status reports, the Commission notes that ordering paragraph D in the September 20 Order states, "NEPOOL and/or ISO-NE are required to make progress reports every 90 days as to their progress in implementing the market design reforms discussed above." The Commission intended to have ISO-NE and NEPOOL provide updates to the nodal pricing implementation process in those reports. The Commission recognizes and shares NICC's desire to acquire an understanding of ISO-NE's and NEPOOL's implementation path and the time-line attached thereto. However, the Commission will not require a separate report or implementation plan to be filed 30 within 30 days.

88. The Commission denies NICC's request to require ISO-NE and NEPOOL to offer all load the option to pay nodal prices no later than 18 months after the issuance of the September 20 Order. While the Commission recognizes and understands the frustration of parties who point to the CMS/MSS Order's directive on this subject and the inconsistent progress made since then, the Commission views a line-in-the-sand approach to establishing the deadline for nodal pricing implementation at this time as unwise and restrictive. As noted above, the Commission intends to exercise oversight on movement towards nodal pricing via the 90-day status reports. The Commission strongly

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[36] ISO New England, 91 FERC ¶ 61,311 at 62,071 (2000) (the CMS/MSS Order).

urges ISO-NE and NEPOOL to: (1) adhere to their 18-month time frame for full nodal pricing implementation; and (2) include in the status reports obstacles to and delays in maintaining that timetable.

K. Operating reserve issues

89. In its comments filed in response to the initial NE-SMD filing, National Grid argued that the allocation of costs and revenues should be determined on the basis of the Real-Time Adjusted Load Obligation Deviation, which adjusts to account for real-time bilateral transactions, as this reveals a given participant's actual reliance on the Real Time Market and allocates those costs or credits appropriately. National Grid also stated that the same flaw identified above may apply to the allocation of the non-synchronized condensing Operating Reserve charges for the Real-Time Market as well as in the allocation of Real-Time Operating Reserve Charges for Daily RMR Resources. That same flaw is the use of the Real-Time Load Obligation Deviation, among other data, in the determination of Operating Reserve charges for the Real-Time Market and of the allocation of Real-Time Operating Reserve Charges for Daily RMR Resources. The Commission sought clarification and ordered ISO-NE and NEPOOL within 30 days to either to modify the tariff as suggested by National Grid, or else to file a statement as to why the proposed method is superior.

90. In the compliance filing of October 21, 2002, ISO-NE and NEPOOL state that Section 3.2.6 of Market Rule 1 has been modified to reflect the Real Time Adjusted Load Obligation Deviation change. They also conclude, in response to the Commission's directive, that "it is better to use Real Time Load Obligation Deviation instead of Real Time Adjusted Load Obligation Deviation as part of the allocation processes of both non-synchronized condensing Operating Reserve Charges for the Real-Time market and the Real Time Operating Reserve Charges for Daily RMR Resources." ISO-NE and NEPOOL argue that, were Real Time Adjusted Load Obligation Deviation used in calculating these charges, "there would no longer be any distinction between internal bilateral transactions for load and internal bilateral transactions for energy."[37] ISO-NE and NEPOOL assert that this distinction affords important flexibility to participants, who want the ability either to transact for just energy or to be able to take on the greater responsibility of transacting for load, and that this flexibility is particularly important to generators selling energy to marketers. NEPOOL and ISO-NE further argue that there are a number of methods available to participants wishing protect themselves from the proposed cost allocation scheme, such as Day-Ahead bidding strategies that avoid such deviations or Real-Time internal transactions for load.

[37] October 21 compliance filing at 12.

91. National Grid filed a protest to the compliance filing regarding the allocation of non-synchronized condensing Operating Reserve charges for the Real Time market and real-time Operating Reserve Charges for daily RMR Resources. National Grid dismisses ISO-NE's and NEPOOL's explanation as unfounded and argues that relying on Real Time Load Obligation Deviation would incorrectly allocate costs to those customers who wish to avoid bilateral purchases on the real-time energy market. National Grid asserts that the flexibility to which ISO-NE and NEPOOL point comes at the expense of other participants forced to bear increased costs.

92. Commission response: the Commission finds that ISO-NE and NEPOOL did indeed comply with Commission's directive when they supplied a statement endorsing the use of Real Time Load Obligation Deviation over Real Time Adjusted Load Obligation Deviation. However, the Commission does not find that ISO-NE's and NEPOOL's explanation provides an adequate illustration of why Real Time Load Obligation Deviation is preferable, particularly in light of the protest filed by National Grid, and is therefore unable to decide which obligation deviation is the most efficient in allocating costs associated with Operating Reserve Charges. The Commission directs ISO-NE and NEPOOL, within 30 days of the date of this order, to file an additional rationale for why they deem Real Time Load Obligation Deviation preferable to Real Time Adjusted Load Obligation Deviation in allocating Operating Reserve charges. Specifically, the Commission requires ISO-NE and NEPOOL to: (1) clarify the difference between Real Time Load Obligation Deviation and Real Time Adjusted Load Obligation Deviation,
beyond that offered in section 3.2.1 of the tariff ; (2) distinguish between internal bilateral transactions for load and internal bilateral for energy; and (3) elaborate on the flexibility Real Time Load Obligation Deviation affords generators selling to marketers.

L. Regulation service

93. PG&E notes in filed comments that certain market features, such as payment for regulation ramping, have been deferred in order to implement NE-SMD quickly. PG&E requests the Commission to direct ISO-NE to implement these reforms in the most expeditious manner and additionally, provide quarterly status reports on the progress of the implementation. Similarly, NU stresses the need for payment for regulation movement to enhance flexibility of generation response, encourage fast start generation, reduce the need for uplift payments and maintain system reliability of tie lines, and in its rehearing request asks the Commission to order ISO-NE to implement payment for regulation movement within six months of the start-up date for NE-SMD.

94. Responding to the Commission's directive in the September 20 Order to explain why it must abandon its current regulation settlement mechanism,[38] ISO-NE explains in its October 7 compliance filing that in order to implement NE-SMD, it adopted PJM's software, and along with it, PJM's market designs, manuals, and databases. As a consequence, settlement for regulation service provided by the generators would need to be changed from the settlement method used currently in ISO-NE to that used in PJM. In order to retain the current ISO-NE settlement, the rules, manuals, software, database structures, settlements and participant interfaces adapted from existing PJM materials would have to be significantly altered. ISO-NE estimates that this would delay implementation of NE-SMD by up to twelve months. ISO-NE describes its initial Market Rule 1 filing as a starting point and is committed to continuing improvement in several areas (as the Commission also noted in the September 20 Order). ISO-NE further notes that, during the period in which the Commission finalizes its generic SMD rule, it would not be prudent for ISO-NE to implement significant alterations to its market design.

95. Commission response: in the September 20 Order, the Commission addresses the need for other desirable market improvements lost in the transition to SMD. We recognize ISO-NE's commitment to implement market enhancements as soon as the requirements of the final SMD rule are known and program development can be completed, and will not now require changes in its regulation settlement methodology. In the September 20 Order we ordered quarterly status updates from NEPOOL and/or ISO-NE, and thus will not repeat that requirement here. We therefore deny the requests for rehearing by PG&E and NU.

IV. Remaining Non-Technical Issues

M. NEPOOL's information policy

96. VPPSA, in its protest to ISO-NE's and NEPOOL's original SMD filing, argued in favor of a new policy regarding the release of proprietary transactional and bidding data, stating that market data such as bids and offers should be publicly released as close to real time as practicable, so as to render market operations more transparent.[39] VPPSA

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[38] September 20 Order at P 140.

[39] See VPPSA protest to initial SMD filing at 5-6, citing Comments of Transmission Access Policy Study Group on Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, Docket No. RM01-12-000,
(continued...)

now seeks rehearing of the Commission's decision not to require NEPOOL to revisit its information policy in light of the changes being proposed in Market Rule 1, or, as an alternative, asks the Commission to require ISO-NE and NEPOOL to make a filing within 30 days in which they either propose changes to the policy, or justify the retention of the policy in its present form.

97. Commission response: we will deny rehearing. In the September 20 Order, on the basis of assertions by NEPOOL and ISO-NE that they are currently reviewing the NEPOOL Information Policy to ensure that it conforms with the new markets proposed by their NE-SMD filing, we declined to preempt that process by prematurely reevaluating the information policy currently in place.[40] VPPSA has provided no additional reasons as to why we should do so now. We will also deny VPPSA's alternative proposal to require ISO-NE and NEPOOL to make a new filing within 30 days. We will, however, require ISO-NE and NEPOOL to include information in their 90-day progress reports as to the progress of their reevaluation of the information policy.

N. Applicability of the Commission's final SMD rule to New England

98. CTAG requests rehearing generally as the NE-SMD relates to the ongoing SMD proceeding at FERC. CTAG states that the Commission should recognize that different regions of the country have different needs and circumstances and that the application of one set of market rules nationwide will not prove effective in meeting the needs of the various regions.[41] Particularly with regard to Connecticut's standard offer period for retail competition, which CTAG notes has not developed as contemplated, CTAG is concerned that the RMR and LMP changes will not likely achieve the market-based response envisioned by the Commission in Connecticut. CTAG also urges the Commission to refrain from ruling on NE-SMD until the conclusion of the FERC SMD proceedings.[42] CTAG notes that since ISO-NE has committed to implement the market changes required by the final SMD rule, FERC acceptance of this proposal is essentially requiring ISO-NE to change its market rules twice in a short period of time and to incur the associated costs.

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[39](...continued)
filed April 10, 2000 at 39-42, FERRIS Accession No. 20020410-5144.

[40]September 20 Order at P 43.

[41]Request for Rehearing at 2.

[42]Request for Rehearing at 14-15.

99. Similarly, MMWEC asks the Commission to state that, once a final SMD rule is issued, it will evaluate the costs and benefits of harmonizing any inconsistencies between NE-SMD and the final SMD rule, and decide whether to require conformity with the final SMD rule on that basis. VPPSA states that it disagrees with the proposition that ISO-NE's current Market Rule 1 would necessarily have to be superseded by the final SMD rule, and NU suggests that it is unreasonable for the Commission to require New England to adopt policies in the SMD NOPR before it becomes a final rule.

100. Commission response: while we address CTAG's concerns on specific issues elsewhere in this order, we deny rehearing on the more general issues as follows. This overhaul of the NEPOOL market structure is the result of an ongoing stakeholder process within NEPOOL and reflects the widespread support of participants that follows prior Commission directives as described in the September 20 Order.[43] This process goes back to 2000, is very much a regional approach specific to NEPOOL, and is not the result of the FERC SMD proceeding; therefore, CTAG's argument that the proposal does not apply to the region's needs and circumstances is unfounded. Further, as noted above, the Commission is providing relief for Connecticut customers by committing to allow the costs of new transmission upgrades for Connecticut to be spread across the region.

101. The Commission provides the following clarification to MMWEC, VPPSA and NU, and denies CTAG's request that we not rule on NE-SMD until the Commission's issuance of a final rule in SMD. It is our view that the NE-SMD as modified contains many attributes of the SMD contemplated in the NOPR, and at the time that the Commission considers the application of our national SMD rule to New England, we will take into account the efforts already made and resources previously expended by the participants, as well as specific regional concerns that might mitigate in favor of adjustments that are specific to New England. We recognize that seams issues have been a continuing issue in the Northeast, where differences in the three ISOs' market designs have led to difficulties in transacting across borders, but we also note that the proposed NE-SMD is intended in part as a transitional measure to address those seams problems. The Commission's SMD process contemplated possible regional differences in some areas of market design. While there may be some changes needed to reduce seams, we do not contemplate at this time that major changes would be needed to NE-SMD after issuance of a final SMD rule.

O. Status of NERTO

[43] September 20 Order at PP 2 - 4.

102. VDPS asks for clarification regarding the extent to which issues raised regarding NE-SMD will be revisited in proceedings regarding the clarification of a Northeastern RTO (NERTO). On November 22, 2002, the boards of ISO-NE and NYISO moved to withdraw their request to form a single Northeastern RTO. Thus, the Commission denies the requested clarification on the basis that it is now moot.

The Commission orders:

(A) The requests for rehearing and clarification of the September 20 Order are denied in part and granted in part, and the compliance filings are accepted in part and rejected in part, as discussed above.

(B) Within 30 days of the date of this order, ISO-NE and NEPOOL must make a compliance filing to explain whether the Commission's understanding regarding the allocation of ARRs and the meaning of the term "Congestion Paying LSE," as discussed above, is correct and to explain any errors in that understanding.

(C) Within 30 days of the date of this order, ISO-NE and NEPOOL must make a compliance filing with regard to the allocation of Operating Reserve charges. ISO-NE and NEPOOL must: (1) clarify the difference between Real Time Load Obligation Deviation and Real Time Adjusted Load Obligation Deviation, beyond that offered in section 3.2.1 of the tariff ; (2) distinguish between internal bilateral transactions for load and internal bilateral for energy; and (3) elaborate on the flexibility Real Time Load Obligation Deviation affords generators selling to marketers.

(D) By February 1, 2003, NEPOOL must make a filing revising its demand response programs to reflect the results of the NEDRI process, as discussed above. If NEPOOL cannot obtain a majority of votes to make this filing, ISO-NE must make the filing by February 1, 2003, noting the fact that NEPOOL could not obtain the necessary majority.

(E) Within 90 days of the date of this order, ISO-NE must file with us a statement as to scarcity pricing, as discussed above.

(F) Within 180 days of the date of this order, ISO-NE and/or NEPOOL must develop performance-based standards for new metering technology, place those standards into the appropriate NEPOOL manual or manuals, and make an informational filing with the Commission, as discussed above.

By the Commission. Commissioners Massey and Brownell dissenting in part with separate statements attached.

(S E A L)

Linwood A. Watson, Jr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool and ISO New England, Inc.	Docket Nos. ER02-2330-001 and EL00-62-052
New England Power Pool and ISO New England, Inc.	Docket Nos. ER02-2330-002 and EL00-62-053
New England Power Pool and ISO New England, Inc.	Docket Nos. ER02-2330-003 and EL00-62-054

(Issued December 20, 2002)

MASSEY, Commissioner, dissenting in part:

Today's order provides additional guidance to New England for completing the migration to its standard market design. I commend all parties in the region for their commitment to this important goal and their diligence and hard work toward accomplishing it.

I disagree with the order's rejection of the ISO's proposal for market mitigation in unconstrained areas. As an initial matter, I am not prepared to say, as the order does, that the Commission will approve only mitigation measures that address well-defined structural problems. Electricity markets are not mature enough to limit mitigation measures in this way. I note that today's order observes that there is very little demand response in the New England market.[1] And while the order takes comfort that HHI levels are now below 1000, such a measure becomes less meaningful as the system reaches shortage conditions in a market with little or no demand responsiveness. Furthermore, I am not confident that market power is enabled only by structural flaws. Some of the market manipulation that occurred in California did not depend on structural conditions such as transmission constraints. What I do know is that there is a risk that any flaws in the market - - structural or otherwise - - will be exploited by profit maximizing entities.

The ISO has demonstrated the appropriateness of its mitigation proposal. Under the ISO's proposal, bids would be reviewed on an ex ante basis only if they exceed certain reference levels by the lesser of 300% or $100 per mWh and if the bids would impact market prices above certain thresholds. There are a number of reasons for accepting this proposal. First, it provides important rules of the road that discourage anticompetitive conduct. Second it is targeted to apply only when participants can unilaterally raise market prices, i.e., exercise market power. Third, it allows reasonable price volatility. The ISO indicates that prices in New England reached the $1000 cap three times during the summer of 2002 and fifteen times during the summer of 2001, and that prices were above $100 during scores of hours during the last two summers - - all without triggering mitigation. Fourth, this mitigation proposal is reasonably consistent with the mitigation procedures now used in the New York market, and thus would not impose a seam between the markets. Finally, it will act as a circuit breaker to prevent the type of price run up that we saw in California. The soaring prices in the California markets, where no on-the-shelf mitigation tools were available, should be fresh in our minds and guide our conclusions.

The ISO's proposal would provide New England customers with meaningful protection against the exercise of market power. Such protection would not exist without it. Therefore, I would approve the ISO's proposal.

For these reasons, I respectfully dissent in part from today's order.

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[1]See paragraph 45.

William L. Massey
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool
and
ISO New England, Inc.

Docket Nos. ER02-2330-001, -002, -003 and EL00-62-052, -053, -054

(Issued December 20, 2002)

BROWNELL, Commissioner, dissent in part:

Consistent with my separate statement in the Commission's September 20, 2002 order, 100 FERC ¶ 61,287, I respectfully dissent.

Nora Mead Brownell
Commissioner