100 FERC ¶ 61, 287
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

New England Power Pool
and
ISO New England, Inc.

Docket No. ER02-2330-000

ISO New England, Inc.

Docket No. EL00-62-039

ORDER ACCEPTING IN PART AND MODIFYING IN PART STANDARD MARKET DESIGN FILING AND DISMISSING COMPLIANCE FILING

(Issued September 20, 2002)

1. In this order, the Commission rules on a filing made jointly by the New England Power Pool (NEPOOL) Participants Committee and ISO New England, Inc. (ISO-NE) proposing a standard market design (NE-SMD) for ISO-NE.[1] We accept the filing in part, and require modifications, as follows. We also dismiss as moot a pending filing relating to ISO-NE's previous congestion management system. Our action here benefits customers by accepting improvements to New England's markets, including a day-ahead and real-time market, locational marginal pricing, mechanisms to mitigate market power, demand response programs, and a capacity resource mechanism. Further, this proposal takes significant steps in the direction of eliminating seams issues with neighboring northeast independent system operators (ISOs), which will in turn facilitate the development of larger regional transmission organizations (RTOs).

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[1]The NE-SMD submitted here for New England is not identical to the design contained in the Notice of Proposed Rulemaking issued by the Commission on July 31, 2002 (Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 100 FERC ¶ 61,138 (2002) (SMD NOPR)), in which the Commission proposed a standard market design (SMD) for wholesale electric markets.

BACKGROUND

Introduction

2. Since the spring and summer of 2000, ISO-NE and NEPOOL have been seeking to develop and implement a market design for New England markets that includes a congestion management system (CMS) based on Locational Marginal Pricing (LMP)[2] and a multi-settlement system (MSS).[3] ISO-NE and NEPOOL have undertaken this process pursuant to a series of directives from the Commission.[4] While the Commission approved the basic framework of a preliminary CMS/MSS proposal for New England,[5] CMS/MSS has never been fully approved or implemented. During the CMS/MSS process, the Commission issued orders directing the participants in the New England, New York and PJM ISOs to begin negotiations to develop a single northeastern RTO.[6]

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[2]SMD NOPR at P 204 ("Marginal pricing is the idea that the market price should be the cost of bringing the last unit to market (the one that balances supply and demand). LMP in electricity recognizes that the marginal price may differ at different locations and times. Differences result from transmission congestion which limits the transfer of electricity between the different locations. The marginal price of energy at a particular location and time -- that is, the energy LMP -- is the additional cost of procuring the last unit of energy supply that buyers and sellers at that location willingly agree on to meet the demand for energy" (footnotes omitted)).

[3]Id. at P 223 n.127 ("The operation of both a financially binding day-ahead market in conjunction with a financially binding real-time market is also known as a multi-settlement system").

[4]See ISO New England, Inc., 91 FERC ¶ 61,227 (2000); ISO New England, Inc., 91 FERC ¶ 61,311 (2000) (CMS/MSS Order); ISO New England, Inc., New England Power Pool, 95 FERC ¶ 61,384 (2001); New England Power Pool, ISO New England, Inc., 96 FERC ¶ 61,100 (2001); New England Power Pool, ISO New England, Inc., et al., 96 FERC ¶ 61,228 (2001); New England Power Pool, ISO New England, Inc., et al., 96 FERC ¶ 61,317 (2001).

[5]CMS/MSS Order, 91 FERC at 62,059.

[6]Bangor Hydro-Electric Company, 96 FERC ¶ 61,063 (2001) and Regional Transmission Organizations, 96 FERC ¶ 61,065 (2001).

ISO-NE and NEPOOL state that, at that point, they began to coordinate and integrate development of NE-SMD in the context of a potential broader northeastern RTO.[7]

3. On July 15, 2002, NEPOOL and ISO-NE jointly submitted the instant filing, pursuant to Section 205 of the Federal Power Act.[8] The applicants propose to cancel the existing NEPOOL market rules (NEPOOL Rate Schedule 6) and replace them with a new Market Rule 1, as set forth in the tariff sheets in this filing. NEPOOL and ISO-NE state that the filing was developed with input from the appropriate NEPOOL committees during an extensive stakeholder process and is fully supported by ISO-NE. NEPOOL states that Market Rule 1 has been approved by an 87.78 percent vote of the members.[9]

4. NEPOOL and ISO-NE state that the proposed NE-SMD is modeled after the market design of PJM Interconnection, L.L.C. (PJM), and will use software that is substantially the same as that used by PJM. NEPOOL and ISO-NE state that this will reduce seams problems for participants who trade in both New England and PJM and will also simplify the eventual task of reducing seams issues with New York, and that the proposed NE-SMD is a substantial movement toward the standardization of regional wholesale power markets across the northeast and the nation. The proposed Market Rule 1 substantially tracks the PJM Operating Agreement. It includes provisions regarding scheduling, dispatch, LMP calculations, settlements, congestion revenue, Financial Transmission Rights (FTRs) and an Installed Capability (ICAP) requirement. NEPOOL and ISO-NE also submit appendices addressing market monitoring and mitigation, sanctions, FTR auction revenue rights, alternative dispute resolution, and load response programs. NEPOOL and ISO-NE state that over the next several months, they will file

[7]Since the filing of NE-SMD, on August 23, 2002, ISO-NE and the New York Independent System Operator (NYISO) filed a joint petition in Docket No. RT02-3-000 seeking a declaratory order authorizing creation of a Northeastern RTO (NERTO).

[8]16 U.S.C. § 824d (2000).

[9]NEPOOL also notes that the Participants Committee was not able to resolve the issue of the allocation of Reliability Must Run (RMR) fixed payment costs and voltage ampere reactive (VAR) support costs. It further states that some controversial issues (market monitoring and mitigation, limitations on the ability of external transactions to set LMP, and the temporary loss of operating reserve markets) resulted in certain participants abstaining on the approval vote even though they broadly supported NE-SMD. Transmittal Letter at 4.

with the Commission conforming changes to the NEPOOL Agreement and NEPOOL Open Access Transmission Tariff (OATT) that reflect the new Market Rule 1.

Day-Ahead and Real-Time Markets

5. NEPOOL and ISO-NE propose to implement a bid-based, security-constrained Day-Ahead and Real-Time energy market.

6. Participants may make supply offers, demand bids, and virtual bids (bids not backed by physical supply or demand) into the Day-Ahead Market. Those bids and offers will be financially binding. ICAP resources[10] that are not self-scheduled or traded bilaterally are required to participate in the Day-Ahead Market. Other resources may self-schedule, and such self-schedules may include decrement bids, under which the participant commits to reduce output if the price falls below a certain level. The Day-Ahead Market may include external transactions.

7. Each day, after the Day-Ahead Market closes at noon, ISO-NE will perform a reliability assessment and evaluate the bids and offers submitted, and by 4:00 p.m. ISO-NE will post day-ahead LMPs and hourly schedules. A rebidding period will begin at that point, during which parties not selected for the Day-Ahead Market can modify their offers. At 10:00 p.m., ISO-NE will post its reliability plan for the next day, including needs for ancillary services, and will designate units that must run for reliability (RMR units) for that day.

8. The Real-Time Market will include hourly scheduling of external transactions, and ISO-NE will continuously update its need for energy and regulation service throughout the day. Participants will also be able to adjust output of their units hour-by-hour.

Ancillary Services

9. Parties will be able to self-supply regulation service, or may purchase regulation service bilaterally or through the NEPOOL Regulation Market. As for Operating Reserves, NEPOOL will eliminate its current Operating Reserve markets, but plans to implement a new spinning reserve market, currently being developed jointly by ISO-NE and PJM, in 2003; meanwhile, NE-SMD provides for compensation to providers of

[10] ICAP resources include supply- or demand-side resources that meet the qualifications in accordance with Market Rule 1 to supply ICAP and are designated as such by NEPOOL participants.

operating reserves similarly to the compensation of providers of such services in PJM.[11] ISO-NE schedules resources for energy and to meet regional Operating Reserve objectives, and resources scheduled in this way with accepted offers in the Day-Ahead and Real-Time Markets will be guaranteed to recover their costs, as bid, through receiving Operating Reserve payments. NEPOOL and ISO-NE note that, while this is a deviation from the CMS/MSS regime, under which participants were able to self-supply Operating Reserves, such self-supply is not necessary under NE-SMD since there is no Operating Reserve product or payment. NEPOOL and ISO-NE anticipate that any new Ten-Minute Spinning Reserve (TMSR) market will allow participants to self-supply that product.

LMP

10. Prices will be based on LMP, which will initially be nodal for supply, but zonal for loads.[12] NEPOOL and ISO-NE propose LMP-based pricing, determined on an ex post (after the fact) basis, within the $1,000 bid caps for energy and ICAP currently in place in New England. Initially, NE-SMD will use zonal pricing for load. Zonal prices will be calculated for the Day-Ahead and Real-Time markets using a load-weighted average of the LMPs at the nodes within each Load Zone. Initially, there will be one Load Zone for each of New England's eight reliability regions, but ISO-NE may alter these Load Zones over time. NEPOOL and ISO-NE state that they have adopted zonal rather than nodal pricing for load because of features unique to New England.[13]

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[11]Generators bidding into the energy market will also be providing operating reserves, and will be paid their opportunity costs. There will be no separate availability bids for resources to signal that they are available to serve as operating reserves.

[12]ISO-NE states that its software will support nodal pricing for load once the necessary procedures, protocols, hardware and software for such pricing are in place in New England. Transmittal Letter at 2.

[13]NEPOOL and ISO-NE state that nodal pricing cannot be used for load until improvements are made to the metering and reporting infrastructure in New England. Currently, customer load is mapped to each pricing zone and then allocated to Load Assets, which are the various suppliers serving load within that zone. To implement nodal pricing, the transmission and distribution companies that serve as meter readers in New England will have to remap customer load to separate nodes, rather than to separate suppliers. ISO-NE and NEPOOL anticipate that this process will take approximately 18

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11. NEPOOL and ISO-NE propose to implement an ex post pricing scheme in the Real Time Market, which would limit the ability of external transactions to set the five-minute Real Time LMP. As proposed, the five minute prices would be set through a two-step process. First, dispatch software would calculate the five-minute Dispatch Rate needed to balance load and generation. Second, actual prices would be set by the resource with the highest price equal to or less than the Dispatch Rate. External transactions are block loaded on an hourly basis and cannot adjust energy in response to load and/or price changes on a five minute basis, meaning that external transactions are unable to balance load and generation on that same five minute basis. Thus, external transactions cannot set the Dispatch Rate and are thus only eligible to set the Real Time LMP if those external transactions are priced lower than the Dispatch Rate.

ICAP

12. The ICAP regime in New England's proposed NE-SMD deviates from the PJM model, and is instead based substantially on that of NYISO. The NE-SMD ICAP proposal adopts the Unforced Capacity (UCAP) standard for ICAP used by PJM and NYISO,[14] incorporates supply and deficiency auctions and provisions to accommodate intra-month load shifts.

13. ICAP resources must submit offers into the Day-Ahead Market for all capacity that is not self-scheduled. ICAP resources not scheduled day-ahead or self-scheduled may be sold bilaterally or offered in the re-offer period. ICAP resources sold bilaterally to support a transaction external to the New England control area may be recalled if ISO-NE declares a Maximum Generation Emergency. New England ICAP resources must delist in order to sell energy on a non-recallable basis into other control areas. If called on, ICAP resources will receive applicable real-time LMP. Participants who are deficient in meeting their ICAP obligations will be assessed a deficiency charge of $6.66/kW-month.

Financial risk management

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[13](...continued)
months. Until then, they urge the use of zonal pricing for load.

[14]UCAP is equal to the rated capability of a generating resource, adjusted downward by its forced outage performance. Transmittal Letter at 10.

14. NEPOOL proposes to allocate 100 percent of FTRs (rights to receive credits in order to hedge against congestion charges) by auction, in contrast with PJM, which allocates FTRs partly by auction and partly in conjunction with firm services. NEPOOL states that this will more effectively allow those entities that most value FTRs to acquire them. NEPOOL has also created a separate system of tradable financial rights called Auction Revenue Rights (ARRs), which will allocate the revenues from the FTR auctions back to the entities that must pay for congestion. ARRs will be allocated to congestion-paying entities**,** transmission customers, Load Serving Entities (LSEs) in the Northeast Massachusetts Reliability Region (NEMA), and entities that pay for transmission upgrades that increase the transfer capability of the NEPOOL transmission system (Qualified Upgrade Awards or QUAs). ARRs are allocated from each generator source node or tie line source external node to each load node, using a four-stage ARR allocation procedure. A proportional adjustment will be applied to the ARRs to ensure distribution of all available FTR auction revenues each month.

15. NEPOOL also proposes to award QUAs, which are revenues awarded to any entity that pays for transmission upgrades that increase transfer capability on the NEPOOL transmission system and thus enable ISO-NE to award additional FTRs in the FTR auction. The amount of the QUA will be consistent with the new revenues arising from the upgrade. The QUA process is a temporary measure which ISO-NE anticipates replacing by December 31, 2004.

Market power mitigation and treatment of RMR Units

16. Appendix A to Market Rule 1 sets forth New England's proposed approach to market power monitoring and mitigation. Similarly to New York, NEPOOL and ISO-NE adopt the use of conduct and market impact tests to identify exercises of market power warranting mitigation. The conduct and market impact tests become more stringent as transmission constraints become more significant, with the most stringent tests applying in chronically constrained areas formally identified as Designated Congestion Areas (DCAs). For these regions, New England proposes to develop pre-specified congestion thresholds that will serve as "safe harbor bid caps" for all units in the region. The congestion threshold is an estimate of what a new peaking unit would require to enter the market in that region, reflecting the incremental operating cost for a hypothetical combustion turbine peaking unit (proxy CT unit) plus an annual fixed cost component based on the number of hours such a unit would be expected to operate.

17. Also, resources in DCAs may be classified as Reliability Must-Run (RMR) units. These are units which must be run during certain periods to alleviate transmission

congestion, and so are likely to have market power at those times. This designation entitles the unit to apply for compensation under one of two specified RMR contracts if the unit believes that it could not profitably operate under the proposed congestion threshold for DCAs. New England proposes the RMR contract option as a backstop for RMR units in DCAs that may not be adequately compensated under the proposed safe harbor bid cap.

18. NEPOOL and ISO-NE state that there are many areas in New England that are import-constrained, within which it has been necessary to designate units as RMR and to negotiate separate RMR agreements with generators. ISO-NE also states that it has had difficulty negotiating RMR agreements under Market Rule 17, and that this method of obtaining energy for transmission-constrained areas (along with issuing Requests for Proposals to provide energy supply) does not provide sufficient market signals to bring new capacity into such areas. According to NEPOOL and ISO-NE, the implementation of LMP will somewhat address this problem, since units will now receive higher location-based prices. However, ISO-NE believes that it should also implement new mitigation rules which will work in conjunction with LMP and other market realities to bring new capacity into these import-constrained areas.

19. ISO-NE has therefore developed a proposal under which it will negotiate RMR agreements based on fixed costs, and can apply mitigation based on the likelihood of a generator's exercising locational market power within a DCA. Mitigation within DCAs would be calculated based on the safe harbor bid cap discussed above. ISO-NE sets out the procedure to be used when an RMR Agreement is required, and also sets forth a pro forma "RMR Mitigation Agreement" for units that wish to continue to sell at market-based rates and a pro forma "RMR Cost-of-Service Agreement" for units that would otherwise shut down and that ISO-NE has determined are required for system reliability.

20. NEPOOL and ISO-NE state that the members of NEPOOL have been unable to agree as to the allocation of fixed-cost charges that may arise from mitigation agreements. NEPOOL therefore provides two options for allocation of such costs. Both options would allocate the costs pro rata to parties in proportion to their usage for the month, but Option 1 would allocate such costs within the affected reliability region of New England only, whereas Option 2 would allocate such costs to all parties regardless of the location of their loads.

Effective Date

21. NEPOOL and ISO-NE propose that the general effective date for NE-SMD and Market Rule 1 (the NE-SMD Effective Date) is the date that will be determined by the ISO and posted on its web site, based on an assessment of the new market software and the impact on the market of the particular date, but that this date will not occur until (1) the Commission has issued an order authorizing Market Rule 1 to take effect; (2) at least two weeks have passed since the ISO has provided written notice to the Commission that Market Rule 1 and its associated software are in place, and (3) notice of the effective date has been published on ISO-NE's web site for at least 48 hours.

22. NEPOOL then states that the ICAP Effective Date will be a date subsequent to the NE-SMD Effective Date, because some of the information needed to operate the market must be collected during the initial period of the new energy market's operation, and will be a date fixed by ISO-NE that is (1) the first day of a calendar month; (2) at least one full month after the general NE-SMD Effective Date, and (3) at least 30 days after the ISO has provided notice to the Commission that the NEPOOL System Rules and software necessary to implement the ICAP market are in place and functional.

23. Finally, a November 1, 2002 effective date is requested for the provisions of the Market Rule relating to Financial Transmission Rights and FTR Auctions, so that the necessary allocation of FTRs can take place in advance of the implementation of the new energy market (which could occur as early as December 1, 2002).

DISCUSSION

Procedural Issues

24. Notice of the NE-SMD filing was published in the Federal Register,[15] with interventions and protests due on or before August 5, 2002. On July 26, 2002, however, NEPOOL and ISO-NE notified the Commission that they would not object to the Commission's not acting on this filing until September 20, 2002, and they waived their right under Section 205 to an earlier ruling.[16]

25. Motions to intervene and protests were filed by the parties listed in the Appendix. ISO-NE filed supporting comments, and NEPOOL and ISO-NE filed a joint answer to the protests. On August 22, 2002, EPSA filed comments. ISO-NE filed an answer to the

[15] 67 Fed. Reg. 48645 (2002).

[16] Letter from NEPOOL and ISO-NE counsel dated July 26, 2002.

late-filed motions for intervention and protests, NICC filed a reply to the joint answer, and NECPUC amended its motion to intervene to add comments.

26. The notices of intervention and the timely, unopposed motions to intervene serve to make the intervenors listed in the Appendix 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 interventions by certain parties also listed in the Appendix and accept their protests. 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 permit NEPOOL's and ISO-NE's joint answer to the comments and protests on the basis that it has provided information that has assisted us in ruling on this application. We will, however, reject ISO-NE's answer to the late-filed motions to intervene and protests, and NICC's reply to NEPOOL's and ISO-NE's joint answer, on the basis that those pleadings do not provide any additional information that is of assistance to us in this proceeding.

Analysis

I. Introduction

27. We begin by commending NEPOOL and ISO-NE, and their members, for their extensive efforts in developing this standard market design. We recognize that, as NEPOOL and ISO-NE themselves state, some desirable market design elements (such as reserve markets and fully nodal pricing) are not yet present. But NEPOOL and ISO-NE have developed a standard market design that is superior to the market design in place in New England now, particularly in its treatment of congestion management problems through LMP and its superior allocation of congestion costs.

28. We recognize, as well, that there are differences between NE-SMD and the market design set forth in the Commission's SMD NOPR. Given that NEPOOL's and ISO-NE's design, as modified, is superior to the market design currently in place, will achieve greater consistency with neighboring transmission organizations, and is generally consistent with the market design principles articulated by the Commission, we will accept it, effective as of the dates requested. For the same reason, we deny NSTAR's request that we reject the filing. We view NEPOOL's and ISO-NE's filing here as a platform on which to build a market design not only for New England, but for a future

northeast RTO, and because this filing goes in that direction, we view it as worth implementing now.[17]

29. Further, as all parties recognize, the Commission has not yet issued its SMD final rule. When a final rule is implemented, it will supersede all market designs in place at that time, subject to exceptions that may be allowed for regional flexibility. Therefore, parties should be on notice that any elements of NE-SMD that ultimately prove different from the Commission's final rule may have to be revisited at that time.

II. Market monitoring and mitigation provisions and treatment of RMR costs

A. Mitigation of market power

1. NEPOOL'S PROPOSAL

30. ISO-NE, in consultation with its Independent Market Advisor, proposes to identify resources that may be exercising market power by comparing their current energy supply offers with a pre-determined proxy for what a profit-maximizing resource would offer if it had no market power. When the actual supply offer significantly exceeds the proxy offer – the "reference offer" or "reference price" – an investigation is triggered that may result in mitigation that prospectively computes market-clearing prices by using reference offers as the mitigated resources' actual supply offers.[18] An investigation begins with ISO-NE identifying bids that significantly exceed reference levels (the conduct test). It then determines the impact of these unmitigated offers on market-clearing prices and uplift payments (the impact test). If the effect is not significant (i.e., market impact thresholds are not exceeded), the investigation ends without mitigation. If the effect of the unmitigated offers on market-clearing prices and/or uplift payments is significant, the monitor consults with the bidder to determine if

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[17]Some parties have argued that NEPOOL will incur significant costs to implement market reforms which, in turn, may need to be reformed again when the Commission issues a final SMD rule. We note, however, that it is unlikely that the Commission's SMD will be implemented nation-wide prior to 2004, and since NEPOOL proposes to implement its NE-SMD by January 1, 2003, New England will, at the least, benefit from a market design that is superior to the current design for a year or longer.

[18]ISO-NE will determine a reference price for each resource through the procedures set forth in Appendix A, Sec. 5.6.1 of its filing, using data from the resource's prior supply offers, LMP from the resource's location, and other inputs.

the offer was justified by competitive conditions. If ISO-NE determines that the bid was justified, the investigation ends without mitigation. Otherwise, mitigation for a period up to six months may be implemented.

31. The degree to which a supply offer may exceed its corresponding reference offer before triggering an investigation that could result in mitigation depends on transmission constraints. At the first level of mitigation, when the transmission system is unconstrained, offers to supply energy are not investigated unless they exceed their corresponding reference values by the lesser of 300 percent or $100 per MW-hour. At the second level of mitigation, if a transmission constraint (within New England or elsewhere) 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 value by the lesser of 50 percent or $25.

32. Finally, at the third level of mitigation, in chronically constrained areas (Designated Congestion Areas or DCAs), all supply offers greater than their corresponding reference values will fail the conduct test unless the supply offer is less than or equal to a pre-specified congestion threshold (DCA safe harbor bid). The DCA safe harbor bid reflects the incremental operating cost for a hypothetical peaking unit (proxy CT unit), plus an annual fixed cost component based on the number of hours that unit would be expected to operate. For units in these areas, market impact tests are also tighter: a bid that fails the conduct test will fail the market impact test if it increases the market-clearing price by an amount equal to the annual fixed cost component of the congestion threshold.

2. POSITIONS OF INTERVENORS

33. Braintree asserts that the market monitoring provisions of Market Rule 1 are too lax, that the market monitor should not wait until the reference price is triggered to begin aggressive monitoring activities, and that reliance on the reference price and proxy CT standards will not ensure just and reasonable prices. Rather, Braintree suggests, the market monitor should look at a generator's own costs to determine whether market power is being exercised. NEPOOL in its response states that the use of reference prices is consistent with its existing Market Rule 17, and was approved by the Commission for use by NYISO.[19]

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[19] NEPOOL response at 32, citing New York Independent System Operator, 99 FERC ¶ 61,246 (2002).

34. With regard to NEPOOL's DCA proposal, NUSCO criticizes the lack of clarity in defining DCAs. It further urges the Commission not to approve the DCA proposal because it will encourage gaming, in that generators within a DCA will set their prices higher than necessary since they know that they will not be mitigated until they reach the DCA threshold. UI similarly asserts that the DCA threshold price will unfairly allow unused baseload (rather than peaking) capacity to obtain the high threshold price. NEPOOL, in response, states that its proposal includes a four-month process for determining DCAs, in which NEPOOL members can participate.

35. NSTAR similarly argues that Market Rule 1 will fail to mitigate market power in load pockets, and argues that the DCA threshold is not just and reasonable since it is based on the costs of a hypothetical unit rather than an actual unit or units. NSTAR argues that this hypothetical threshold is excessively generous, and that NEPOOL has failed to show why such generosity is necessary to encourage generators to enter or remain in the load pocket. NSTAR also states that this policy is contrary to the Commission's SMD NOPR, under which generators within a load pocket would be required to offer power into the market in circumstances when the market was not competitive, and which provides for bid caps specific to each unit. NSTAR argues that the CT proxy price that NEPOOL instead proposes will allow generators to exercise the market power that they possess through being located in a congested area to collect prices that are higher than their marginal costs. NSTAR points to Sithe's construction of its new Mystic plant as proof that excessive prices are not necessary to induce new generator entry into load pockets. Finally, NUSCO states that proper treatment of RMR units will provide as much mitigation as is necessary in New England.

36. Other parties support NEPOOL's proposed provisions for DCAs and the use of a proxy CT standard, but seek modifications. DENA and NES support modifications to the rule’s mitigation thresholds to ensure that those resources whose offers do not exceed their reference prices by more than the DCA safe harbor bid are not mitigated. NES also asserts that further adjustments to the Commission's formula for calculating the DCA safe harbor bid are required to ensure that the safe harbor bid will send correct price signals.[20] Waterside asks the Commission to ensure that generators are compensated for

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[20]Specifically, NES states that the DCA safe harbor bid formula should be revised to reflect how frequently peaking units are likely to run in New England, the likely costs of locating in constrained areas, a revised assumption of the necessary ratio of debt to equity and the likely costs of arranging long-term gas supply and turbine services. They also state that the proxy CT proposal should be revised to give ISO-NE greater flexibility
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their service in DCAs through a capacity payment scheme that guarantees recovery of generators' fixed costs and provides a significant return on investment. NRG suggests that the proxy CT scheme will not allow generators sufficient opportunity to earn sufficient revenues during periods of congestion to make entry into DCAs worthwhile. Finally, NES also urges that ISO-NE adopt clearer criteria as to how DCAs will be designated, and that ISO-NE include all bids that it accepts in its reference price calculation.

37. In response to the above points, NEPOOL states that the proxy CT formula is an attempt to "provide additional incentives to locate generation in load pockets," but "is not designed to guarantee a return on investment to new generators, which would be a return to cost of service regulation."

38. With regard to other issues, VPPSA seeks additional transparency with regard to NEPOOL's pricing mechanism and asks the Commission to revisit the NEPOOL Information Policy regarding the confidentiality of pricing information. PSEG expressly supports the possibility of manual correction for incorrect mitigation.

3. COMMISSION RESPONSE

39. The Commission will accept much of NEPOOL's mitigation and market monitoring plan, but will require modifications and further information from NEPOOL regarding its proposal.

40. NEPOOL's plan takes the approach that as transmission becomes more constrained, opportunities to exercise market power increase, and hence, regulatory oversight should become tighter. Thus, it adopts the tightest restrictions on bidding behavior in chronically constrained areas. NEPOOL is concerned, however, that such mitigation might discourage needed entry or encourage premature exit of capacity,[21] since prices set at reference levels of marginal units may not adequately compensate such

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[20](...continued)
to negotiate reference levels and RMR agreements. NES' comments at 34-36.

[21]New England's market monitor emphasizes this concern, noting that between 1999 and 2002, except for the NEMA/Boston area, new capacity in chronically constrained areas has not kept pace with announced retirements and deactivations in these same areas. Testimony of Robert Ethier, Attachment 6 to Transmittal Letter, at 19-20.

generators that are seldom called to serve load, a problem ISO-NE confronted under Market Rule 17. The congestion threshold as a safe harbor bid for generators in DCAs is one way NEPOOL proposes to guard against over-mitigation in DCAs where it believes efficient entry and exit decisions are particularly critical to reliability.

41. Although New England's mitigation plan is not identical to that proposed in the SMD NOPR, contrary to NSTAR's claim, mitigation under Market Rule 1 is generally consistent with the approach laid out in the SMD NOPR. Both are focused on local market power issues and rely on specifying bid caps that would apply in non-competitive conditions. Mitigation under Market Rule 1 differs somewhat from mitigation under the SMD NOPR with regard to physical must-offer requirements.[22] New England, comparable to PJM, requires that all ICAP resources be scheduled or bid into the Day-Ahead Market at a price that does not exceed the $1000 per MW-hour cap. Mitigation under the SMD NOPR would require that units with localized market power be scheduled or offered at reference values if market conditions are non-competitive. However, we find the NE-SMD approach acceptable at this time.

42. We will, however, defer acting on that portion of the proposal that would provide for mitigation in the absence of transmission constraints until we receive additional information from NEPOOL and ISO-NE regarding their rationale. Specifically, we will require NEPOOL and ISO-NE to provide us with further information as to why they believe it is necessary to have the first level of monitoring and mitigation, i.e., when the transmission system is unconstrained. The Commission will require that, within 15 days, NEPOOL and/or ISO-NE provide the Commission with factual support and justification for the need for the first level mitigation in addition to the $1000/MWh safety net bid cap that is in place market-wide. Such support should include but is not limited to any analyses of market power, the current and forecasted supply and demand situation, and a report of structural changes since the existing NEPOOL-wide mitigation was first imposed. NEPOOL and/or ISO-NE should also address whether there is concern that opportunities for the exercise of market power exist within the $1,000 bid cap even when there are no constraints, and the effect of the proposal on seams. Following the receipt of this information and the opportunity for comments, the Commission will issue an order on the proposed first level mitigation.

43. With regard to the concerns expressed regarding the designation of DCAs, as NEPOOL has stated, it will conduct an initial four-month stakeholder process during which members can participate in the designation of DCAs, and every year thereafter

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[22]The SMD NOPR's physical must-offer requirement is found at ¶ 399.

NEPOOL proposes to give notice of its DCA designations to its Markets Committee by September 30, and allow for two months of discussion and review before NEPOOL makes an informational filing with the Commission by November 1 of the upcoming year's designated DCAs. Thus, NEPOOL members will have an opportunity to participate in the designation process and express their concerns there. Additionally, as DCAs are developed, we encourage participants to address structural problems through the regional planning process. Further, with regard to VPPSA's request for additional transparency regarding pricing, NEPOOL and ISO-NE state that they are currently reviewing the NEPOOL Information Policy to ensure that it conforms with the new markets proposed by their NE-SMD filing. The Commission will not, therefore, require modifications to the filing to accommodate either of these concerns at this time.

44. With regard to some intervenors' concerns that use of the DCA safe harbor bid cap will allow excessive returns for some generators, and other intervenors' arguments that the use of the DCA safe harbor bid cap will not allow generators to recover sufficient revenues, the Commission recognizes that there is no way to determine precisely the efficient price for a chronically constrained area subject to market power. On one hand, a freely-determined market price could be too high because it may reflect market power. On the other hand, mitigation that results in a price equal to the marginal cost of the highest cost unit dispatched may not properly reflect the scarcity of generation. Additionally, if the price based on mitigated bids does not allow recovery of fixed costs for units needed for reliability, mitigation would further undermine reliability. New England is trying to establish a balance between these two extremes. Using a congestion threshold as a safe harbor bid cap for all units in a DCA should protect against market power, and still give needed bidding flexibility to some marginal units with reference prices that may not allow recovery of fixed costs. Thus, a congestion threshold would be a bid cap whenever all available capacity in the area is needed to serve load reliably.

45. However, the rationale for a scarcity price and a potentially higher safe harbor proxy bid cap (i.e., higher than the reference price) applies only when transmission constraints and demand conditions in the DCA require the dispatch of all capacity of all available resources within the DCA. At all other times, high-cost peaking units in the DCA would not be dispatched because it would be uneconomic to do so. Therefore, those lower-cost units whose bids would set the clearing prices would be in the same position as similar units located outside the DCA. In this situation, there would be no reason to give such lower-cost generators greater bidding latitude merely because of their location within the DCA, and the mitigation rules within and outside of the DCA should be the same. We will require NEPOOL to modify its mitigation proposal accordingly within 30 days.

46. Further, when New England discusses the market impact test, it is not clear whether the test applies to market-clearing nodal or zonal prices. It should be nodal prices. Otherwise, a bid could have a very significant effect on a nodal price, but when averaged in with other nodal prices in a zone, it could have a much smaller impact on the zonal price. The market impact test should not apply to the zonal price. The Commission will require NEPOOL and ISO-NE to modify its filing within 30 days to provide that the market impact test applies to market-clearing nodal prices.

B. RMR Agreements

1. NEPOOL'S PROPOSAL

47. RMR resources are those resources identified by the ISO as necessary for the provision of Operating Reserve requirements and adherence to North American Electric Reliability Council (NERC), Northeast Power Coordinating Council (NPCC) and NEPOOL reliability criteria over and above those resources required to meet first contingency reliability criteria within a Reliability Region. This designation entitles the unit to apply for compensation under one of two types of RMR contracts. The first, designed for a unit that expects to be economic in some, but possibly very few situations, will receive the highest of (1) the relevant LMP; (2) the lower of the supply offer or reference level; or (3) its Stipulated Bid Cost.[23] The second, designed for a unit that expects to be uneconomic in all periods and that would otherwise seek authority to permanently shut down, will receive a cost-of-service contract to remain available to serve reliability needs. RMR resources may sell ICAP, but any ICAP payments will be offset against the resources' RMR payments.[24]

2. POSITION OF INTERVENORS

48. CTAG charges that NRG's plan to deactivate certain plants located in Connecticut is an exercise in market power, and that if an RMR agreement is entered into with NRG, the fixed and operating costs of that agreement must be scrutinized carefully. CTAG states that any RMR agreement must reflect reasonable costs and not reward the exercise of market power. NSTAR objects to ISO-NE having the ability to negotiate RMR

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[23]Stipulated Bid Costs are the sum of the Stipulated Marginal Cost, the Stipulated Start-Up Cost, and the Stipulated No Load Cost.

[24]See Appendix A to Market Rule 1, Section 3.3.2.

agreements retroactively.[25] Further, NSTAR objects to ISO-NE's having the option to modify the pro forma RMR agreements. NSTAR states that, due to a lack of transparency and price uncertainty in the market, it objects to the confidential nature of the RMR cost of service contracts and would require full public disclosure of costs and revenues used to determine the agreement. Central Maine states that designating certain units as RMR is not a desirable long-term solution, and that LMP will allocate the increased energy costs to the locality and thus send price signals to the market to create better solutions. NUSCO also argues that RMR contracts are a short-term solution to the lack of adequate transmission and generation and should not set a precedent for allocation of the costs of infrastructure upgrades.

49. ISO-NE submits the direct testimony of Dr. David Patton, its independent market adviser, to support the use of the RMR agreements.[26] Dr. Patton states that some resources may not earn sufficient profit to avoid retiring generation, particularly units that are rarely called upon. Dr. Patton suggests that generators should be identified as likely to be designated as a daily RMR unit over the next year. Generators that can demonstrate that it would be uneconomic for them to operate, and that the ISO finds are needed for reliability, would then be eligible to enter into an RMR agreement. NEPOOL and ISO-NE further state that the Commission has specifically recognized the role of RMR Agreements in the SMD NOPR. As noted in the original filing, the proposed Appendix A, taken as a whole, is designed to reduce dependency on RMR Agreements and to make the process of negotiating any RMR Agreement that is necessary as open and transparent as practicable. Lastly, ISO-NE and NEPOOL base the current RMR proposal on the precedents from Market Rule 17.

3. COMMISSION RESPONSE

50. The Commission has previously stated that, under Market Rule 17, ISO-NE has the authority to negotiate individual RMR agreements as are required to maintain and/or improve system reliability.[27] Further, such agreements are to be filed with the

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[25]NSTAR points to language in Section 3.2.2 of Exhibit 2 to Appendix A that "in general, such agreements shall be effective only prospectively."

[26]Supporting Comments of ISO-NE, Attachment A at IV.

[27]The authority of the ISO to negotiate contracts was affirmed in the February 14, 2002, decision involving Sithe's filing of a cost-of-service RMR agreement for its New
(continued...)

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Commission in accordance with the Commission's rules and regulations, and, as such, may be subject to the review of the Commission.[28] We find the inclusion of a pro forma RMR contract in Market Rule 1 beneficial to both ISO-NE and market participants in achieving additional transparency. We have noted in past orders, however, the need for flexibility to address specific RMR situations and are not persuaded by NSTAR that a single pro forma agreement will satisfy every situation in which an RMR agreement is negotiated.

51. With respect to NSTAR's objection to the confidential nature of the RMR agreements, the Commission is also today issuing its order on rehearing of Southern Company Services, Inc., 96 FERC ¶ 61,341 (2001), in which we deny confidential treatment to similar agreements. We therefore similarly find that ISO-NE may not automatically keep RMR agreements confidential. We add that under the Commission's procedures for filing privileged documents, ISO-NE may seek an order from the Commission to obtain privileged treatment for the material supporting particular rate agreements, if necessary.[29]

C. Allocation of RMR costs

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[27](...continued)
Boston units under Market Rule 17.3.2.2(b), which gives ISO-NE the ability to negotiate "a special contractual arrangement" with resources that usually operate out of merit and serve primarily to ensure reliability, to ensure that those resources remain available to ISO-NE. As Market Rule 17.3.2.2 states, "[e]ach such Resource is likely to present a unique situation," and, as footnote 9 to Market Rule 17.3.3.3(b) provides, "[t]he ISO may enter into negotiations with a resource owner for any reasonable payment terms if the ISO reasonably expects the markets will function more reliably, competitively or efficiently as a result." See Sithe New Boston, LLC, 98 FERC ¶ 61,164 at 61,611, reh. den. 100 FERC ¶ 61,106 (2002) (Sithe New Boston).

[28]See Sithe New Boston, supra, 100 FERC at P 17; Mirant Americas Energy Marketing, L.P., 99 FERC ¶ 61,003 at PP 5, 16 (2002) (Mirant). Further, NSTAR's concern regarding ISO-NE's authority to negotiate RMR agreements that are effective retroactively is currently pending before the Commission in Mirant Americas Energy Marketing, L.P. v. ISO-NE, Docket No. EL01-93-005, and the Commission will therefore not consider this issue here.

[29]See 18 C.F.R. § 388.112 (2002).

1. NEPOOL'S PROPOSAL

52. The participants of ISO-NE were not able to agree as to the allocation of certain costs arising from these agreements. NEPOOL and ISO-NE have submitted two options and desires the Commission to choose the more appropriate allocation methodology. While both options would allocate such costs pro rata to Participants and Non-Participants in proportion to their Network Load for the month, Option 1 would allocate such costs within the affected Reliability Region only. Option 2 would allocate such costs to all Participants and Non-Participants irrespective of the location of their Network Load.[30]

53. The issue of how to allocate these fixed costs first arose in Sithe New Boston, supra, in which the Commission accepted a temporary allocation method using the principles of Section 24 of the NEPOOL Tariff, which converts the monthly fixed-cost charge paid to Sithe to a per-hour charge to be allocated among all Participants based on their Network Load or Reserved Capacity in that hour. On April 25, 2002, NEPOOL filed changes to Market Rule 17 that proposed to apply this allocation method to any units receiving monthly capacity-type payments under a mitigation. On June 14, 2002, the Commission conditionally accepted NEPOOL's proposed interim allocation mechanisms subject to condition, explaining that:

> We agree that continuation of NEPOOL's proposed socialized cost allocation methodology may be inappropriate when LMP is implemented and will need to be reviewed at that time. Accordingly, we will accept NEPOOL's proposed changes to Market Rule 17 as an interim allocation

[30]The options are (emphasis added):

> OPTION 1: Any monthly fixed-cost charges paid to Resources pursuant to Agreements negotiated under Appendix A, Section 6 and Exhibit 2 shall be allocated and charged pro rata to Participants and Non-Participants with Network Load in proportion to the sum of their Network Load during that month within the affected Reliability Region.

> OPTION 2: Any monthly fixed-cost charges paid to Resources pursuant to Agreements negotiated under Appendix A, Section 6 and Exhibit 2 shall be allocated and charged pro rata to Participants and Non-Participants with Network Load in proportion to the sum of their Network Load during that month.

measure and will require ISO-NE and/or NEPOOL to propose a revised methodology in their [NE-SMD] filing.[31]

B. POSITIONS OF INTERVENORS

54. CTAG, Braintree, NSTAR, and VPPSA argue for socialization of the fixed costs associated with the RMR Agreements throughout the pool. CTAG and NSTAR argue that the RMR costs are associated with transmission facilities and should be treated as such. CTAG states that socialization of the fixed RMR costs is appropriate because RMR units contribute to the reliability of the New England grid as a whole. NSTAR states that those affected have little or no voice in the negotiation of RMR Agreements, and if such agreements are localized, NSTAR argues that local parties should have control over the agreements and bidding control over the units. VPPSA notes the Commission's position on the importance of stability in contracts in the proper functioning of the markets. Braintree argues that the Commission's approval of system-wide pricing in NEPOOL obfuscated local market power issues and thus perpetuated them, and it would be unfair not to continue socializing these costs until an adequate infrastructure to support competition is developed. Finally, VPPSA states that customers located in a congested area should not be unduly penalized for congestion on the New England grid that may come from a variety of sources, particularly since the agreements were entered into based on rules which socialized the costs of such contracts.

55. By contrast, Bangor Hydro, Central Maine, Central Vermont, Maine Commission, National Grid, NUSCO and ISO-NE argue for assignment of these costs to the reliability region in which they occur. Bangor Hydro states that such allocation will provide appropriate price signals under LMP, and local allocation of such cost is consistent with Commission policy concerning energy uplift costs, facility costs and congestion management.[32] Further, Bangor Hydro notes that in previous orders accepting

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[31]New England Power Pool, 99 FERC ¶ 61,324 at 62,378 (2002).

[32]In the July 3, 2002 order regarding ISO-NE's interim method of allocating energy uplift costs and the allocation of certain facilities costs, the Commission stated that the continuation of NEPOOL's socialized cost allocation methodology "may be inappropriate once LMP is implemented, as LMP does not socialize costs, but allows parties to see and respond to market signals in planning and locating transmission upgrades." ISO New England, Inc., 100 FERC ¶ 61,029, at P 8 (2002). see also ISO (continued...)

congestion management and multi-settlement systems, the Commission expressly instructed ISO-NE that "socialization of congestion costs does not send the correct signals to transmission customers or market participants for the siting of new transmission facilities or generation."[33] National Grid states that such an allocation method is the only one that promotes economic efficiency and matches the congestion topography of the ISO-NE market. Bangor Hydro points to Order No. 2000's characterization of the socialization of costs as distorting consumption, production and investment decisions that ultimately lead to economically inefficient decisions.[34] Central Maine notes that the Commission's SMD NOPR supports its position that the costs of RMR units should not be socialized across the pool. NUSCO supports allocation of RMR fixed costs to the affected reliability region but requests that such costs be shared by those using through and out service (interregional transactions)[35] that cause or benefit from the use of RMR contracts.

56. ISO-NE, supported by the Maine Commission, finds allocation of RMR costs to local reliability areas consistent with the principle that efficiency is enhanced when entities that cause costs to be incurred pay these costs. Further, ISO-NE states that localized allocation is consistent with the tenets underlying LMP, i.e., that proper price signals are necessary for markets to run efficiently. Finally, ISO-NE asserts that the current state of markets in ISO-NE is proof of what happens when costs are socialized, and local customers who do not bear the true costs of must-run service will not resolve the situation so long as price signals are muffled by socialized uplift and single regional clearing prices.

3. COMMISSION RESPONSE

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[32](...continued)
New England, Inc., 100 FERC ¶ 61,245 (2002).

[33]CMS/MSS Order, 91 FERC at 62,072.

[34]Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs., Regs. Preambles 1996-2000 ¶ 31,089, at 31,219 (1999), order on reh'g, Order No. 2000-A, FERC Stats. & Regs., Regs. Preambles 1996-2000 ¶ 31,092 (2000), aff'd., Public Utility District No. 1 of Snohomish County v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[35]"Through and out service" is point-to-point transmission service which exports power from one transmission system to another.

57. In a single settlement market, with system-wide pricing and lacking congestion management, socialization of the RMR fixed costs was deemed appropriate as a temporary allocation method.[36] This was reinforced in an order dated June 14, 2002 accepting proposed tariff revisions to NEPOOL Market Rule 17.[37] We agree, however, with those intervenors who assert that socializing costs of RMR agreements obscures price signals and distorts market results.

58. We reject CTAG's assertion that the benefits of the RMR agreements inure to the grid and should be treated similarly to transmission costs. RMR costs represent the known (and short-term) costs of addressing congestion in identified regions during a specified time period. We find VPPSA's concern for stability inapplicable here as the Commission's orders establishing the current allocation have characterized the current allocation methodology as a "stopgap" and "interim" measure until NEPOOL and ISO-NE were able to implement a new market design including LMP.

59. NSTAR states it has no voice in negotiating RMR agreements. In their joint answer, ISO-NE and NEPOOL find Market Rule 1 does not inhibit loads from entering into bilateral agreements with RMR suppliers. With respect to operational control of RMR resources when not under ISO-NE control, NSTAR is mistakenly attempting to broaden the scope of the RMR agreements, which are not intended to allow the level of control of resources sought by NSTAR.

60. Braintree would wait until sufficient infrastructure to support competition exists to localize RMR costs. We find, however, that without proper price signals to attract transmission projects and generation resources, infrastructure improvements will be slow or not forthcoming at all. Braintree and VPPSA find it unfair to change the rules in the middle of the game, and argue that the Commission actions in accepting socialization of RMR costs perpetuated market power issues. But in fact, the prior allocation

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[36]Sithe New Boston, LLC, 98 FERC ¶ 61,164 at 61,163 (2002) ("The interim allocation method is, however, simply a stopgap measure to ensure that ISO-NE can bill parties appropriately while this matter is pending, and should not be taken as a Commission determination that these costs are congestion costs").

[37]New England Power Pool, 99 FERC ¶ 61,324 at 62,378 (2002) ("While the allocation of capacity payments on a socialized, system-wide basis, as proposed by NEPOOL, is generally consistent with the configuration of NEPOOL's existing markets, NEPOOL states in its filing that it expects to revisit this allocation mechanism in anticipation of ISO-NE's filing to implement LMP in NEPOOL's markets").

methodology was always interim in nature. NUSCO supports localized allocation but would require that those using through and out service share the costs. However, we view NUSCO's argument as internally inconsistent: localized allocation of costs, which NUSCO supports, is inconsistent with allocation the costs of local reliability mechanisms to through and out customers.[38]

61. We find that RMR fixed costs represent costs of relieving congestion in specific regions and therefore should be reflected in the cost of energy in those regions. Numerous Commission orders, noted by the intervenors, indicate that the socialization of costs is inconsistent with an economically efficient market. We agree with ISO-NE that:

> [A]llocation of RMR costs to local reliability areas is consistent with the principle that efficiency is enhanced when entities that cause costs to be incurred pay these costs. . . . [L]ocalized allocation is consistent with the tenets underlying LMP, i.e. proper price signals are necessary for markets to run efficiently, [and] . . . [t]he current state of markets in ISO-NE is proof of what happens when costs are socialized. Local customers not bearing the true costs, due to price signals hidden in socialized uplift and single regional clearing prices, will not act to resolve the situation.[39]

62. We therefore direct ISO-NE to adopt Option 1 for the allocation of RMR costs.

III. LMP and nodal/zonal pricing

1. NEPOOL'S PROPOSAL

63. Market Rule 1 will use locational marginal prices (LMPs) at nodes, load zones and hubs. The LMP methodology will replace the single, system-wide energy clearing price that NEPOOL currently uses. LMP will be determined on an ex post basis, which is a departure from the current ex ante pricing methodology in New England. Market Rule 1 will keep the $1000/MWH bid cap in place on Supply Offers. Eligibility to set the LMP is limited in New England. Generally speaking, the supply offer price from a generator or External Transaction purchase must be economic, able to respond to

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[38]Through and out service generally does not contribute to congestion within a DCA, because it will usually be service out of or around that area rather than into it, and would not usually rely on congested facilities within the DCA.

[39]Comments of ISO-NE at 3.

dispatch requests and following dispatch instructions. Eligibility to set the real-time nodal LMP is, among other things, predicated on the generation unit's supply offer price being less than or equal to the Dispatch Rate associated with that particular unit.

64. ISO-NE will calculate day-ahead nodal prices for each hour in the Day-Ahead Market as determined by the sum of: (1) the price of a participant's offer to supply an additional increment of energy or reduce consumption from the resource; (2) transmission congestion costs (positive or negative) associated with increasing the output of the resource or reducing consumption of the resource; and (3) the effect on transmission losses caused by the increment of load and generation. ISO-NE will calculate the Real-Time Nodal Price every five minutes of the operating day as determined by the sum of: (1) the additional increment of energy offered from a generating unit or an external transaction purchase, where participants are eligible; (2) transmission congestion costs (positive or negative) resulting from increased generation or external transaction purchase; and (3) the effect on transmission losses caused by the increment of load and generation. These calculations will produce a set of nodal Real-Time Prices that, for a given hour, will be integrated to determine the nodal Real-Time Prices for that hour.[40]

65. Initially, the NE-SMD model will use zonal pricing for energy purchases, which was approved in the Commission's CMS/MSS Order.[41] A load-weighted average of LMPs at the nodes within each load zone will serve to determine zonal prices in the Day-Ahead and Real-Time markets. Market Rule 1 proposes eight zones – mirroring NEPOOL's already-established reliability regions – which, according to Section 2.7 (c) of Market Rule 1, ISO-NE may alter over time. Such changes will be filed with the Commission. Hubs within the NEPOOL Control Area will contain a sufficient number of nodes to ensure price calculations at all times and to ensure node unavailability would have a minor price impact. ISO-NE will calculate and publish hourly hub prices for both the Day-Ahead and Real-Time LMP at the nodes in that hub.

2. POSITIONS OF INTERVENORS

66. NICC states that the proposal for zonal pricing for load (1) is inconsistent with prior Commission orders, (2) mutes vital price signals, (3) ignores cost-causation principles, and (4) undermines the primary purpose of LMP. NICC asserts that the

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[40]Section 2.5 (b), Market Rule 1.

[41]CMS/MSS Order, 91 FERC at 62,070.

Commission should reject the proposed pricing mechanism and require changes to Market Rule 1 to allow load the choice between paying nodal or zonal prices. NICC finds unconvincing ISO-NE's explanation that it is impossible to implement nodal pricing for load because of the structure of retail access programs in New England, given the modest nature of those programs. NICC further argues that, in fact, if given a choice, most customers would initially choose zonal pricing, so that NEPOOL and ISO-NE would probably be able to accommodate the small number of customers who would be able to and wish to take advantage of nodal pricing.

67. NERPPA states that since renewable generators must locate their plants near available renewable fuel resources (i.e. wind, water, wood), which are often on the "wrong" side of transmission constraints, LMP will result in the "bottling-up" of this type of generation on the lower-priced side of constraints, which produces lower revenues than other generators and places renewable generation at a competitive disadvantage. NERPPA thus argues that the application of LMP will result in "dirtier" fossil fuel units running before renewable units, thus impeding the development of renewable power, and disadvantaging renewable producers financially. NERPPA urges the allocation of Financial Transmission Rights (FTRs) to renewable power producers to rectify the situation and to permit New England to utilize the region's fuel diversity and protect the environment. CTAG similarly argues that Connecticut is not likely to benefit from LMP's provision of clear price signals for a number of reasons (a concentrated ownership structure in the state, absence of near-term generation expansion, and transition costs attributable to LMP) and that LMP will increase rather than decrease prices in Connecticut in the short term. CTAG therefore asks the Commission to introduce transition mechanisms to reduce the opportunities for the exercise of market power during the transition to LMP pricing.

68. NES argues that Market Rule 1 is flawed because it does not allow a number of load-serving resources to establish locational prices. NES states that throughout the 2001 summer, prices were too low, due primarily to the inability of varying resources to set the clearing price.[42] NES asserts that units running to relieve congestion should be eligible to set locational prices, arguing that ISO-NE has continually used units running at their Low Operating Limit (LOL)[43] to provide congestion relief, but NEPOOL now

[42]NES cites Dr. David Patton, "An Assessment of Peak Energy Pricing in New England During Summer 2001" (November 2001).

[43]The minimum MW value at which the Participant is willing to operate a (continued...)

proposes to disqualify these units from setting locational prices. According to NES, this choice distorts price signals, is inconsistent with efficient markets, and violates the principle that the marginal unit in any market should set the price.[44] Similarly, NES asserts that in keeping resources that are not dispatchable in 5 minutes from setting prices (including External resources, all types of real-time demand response resources and emergency transactions), ISO-NE is stepping away from the reforms it enacted recently[45] and is ensuring that higher-priced resources cannot set price, thus practically guaranteeing an inefficient Real-Time Market.[46] NES asserts that (1) peaking and external dispatchable resources should be eligible to set prices regardless of when they are scheduled, (2) NE-SMD should continue to limit external resource size to 100 MW in order to limit any potential pricing problems from large block loaded resources, (3) dispatchable load should be allowed to set Real-Time prices, and (4) for resources below 50 MW, disqualification should occur if there is a deviation of 5 MW or more. NES states that, by contrast, under Market Rule 1, real-time prices will be set by the most

[43](...continued)
Generator. The LOL can be equal to or greater than zero. The LOL will be used as the minimum value at which the ISO will dispatch a Generator under normal system conditions. This value is required, and once submitted, will become the default value until it is changed by the Participant or is changed by ISO-NE due to a change in the generator's status (ISO NE Market Rules and Procedures, Definitions.)

[44]NES suggests creating a screen in the Day-Ahead Market that would determine, on an hourly basis, whether a unit at LOL which submits offers above LMP is required to maintain local or system-wide reliability. Those resources that could not be replaced at lower cost would then be available to establish the LMP. In the Real-Time market, NES suggests the development of another screen to test whether units operating at LOL in real-time should be eligible to set 5-minute Dispatch Rates and real-time prices. NES' motion at 11.

[45]On April 26, 2002, the Commission enacted a package of reforms (the Patton Reforms) developed from a report by Dr. Patton which were designed, among other things, to make energy pricing more efficient. See ISO New England, Inc., 99 FERC ¶ 61,124 (2002) (Patton Reforms Order).

[46]Under those reforms, quick start units operating at their LOL and External Transactions should be eligible to set clearing prices if they are deemed to be incremental sources of energy. Further, during a reserve shortage, on-line quick start units not flagged for Transmission Congestion are eligible to set prices even if there are lower cost resources providing reserves at that time. See Patton Reforms Order, supra.

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expensive increment of capacity dispatchable in 5 minute intervals that is below the Dispatch Rate. NES argues this creates a bias toward excessively low prices, is counter to efficient pricing principles, and mutes prices during constrained periods. NES furnishes two alternatives: (1) Real-Time prices should be set equal to the Dispatch Rate, on an ex ante basis, or (2) if ex post pricing is required, Real-Time prices should never be set below the Dispatch Rate in circumstances where more expensive resources have been scheduled by ISO-NE. PSEG also protests the absence of the Patton Reforms in the NE-SMD proposal, particularly the inability of in-merit external resources to set Real-Time LMP when these are used to meet reserve requirements and the inability of generating units at their LOL to set prices in both the Day-Ahead and Real-Time Markets.

69. Under Market Rule 1, ISO-NE posts prices at or before 4 p.m. However, the rules allot additional time in the event of software failures or other events. NES deems the timely release of prices to be integral to building confidence in ISO-NE markets and thus urges the addition of explicit language to limit ISO authority to modify market prices except under the circumstances outlined in current Market Rule 15.[47] Additionally, NES suggests that the Commission should require ISO-NE to add reserve markets by May 1, 2003, and that the Commission should ensure that NE-SMD will provide additional information with regard to supply and demand conditions; specifically, information concerning capacity, external resources and Emergency Energy.[48]

70. In their joint answer, ISO-NE and NEPOOL concede that the nodal/zonal pricing mechanism deviates from that of PJM as well as the Commission's SMD NOPR, and they agree that optimally, load should be able to choose nodal or zonal pricing under NE-SMD. However, they reiterate that "the issue is one of timing and resolution of technical impediments."[49] They state that they envision the nodal/zonal model as a temporary feature of NE-SMD which will provide a transitional buffer for retail access programs to expire, as well as for distribution companies to make metering and data systems infrastructure enhancements, prior to full implementation. They also argue that the existing retail access programs – which are almost complete in three of the four affected states – are administered using a uniform pricing model. Eighteen months is identified as

[47]"Monitoring For And Correcting Market Design Flaws And Addressing System Emergencies," Market Rule 15.

[48]For a more detailed list, see NES' motion at 21.

[49]NEPOOL's and ISO-NE's joint answer at 9.

a preliminary estimate of the amount of time before nodal pricing for load can be implemented.

3. COMMISSION RESPONSE

71. The Commission will accept Market Rule 1's proposal to use LMP. The Commission expects the implementation of locational pricing to provide appropriate price signals indicating the value of additional resources or conservation at each node in the transmission system. Many of the aforementioned intervenors, notably NES, characterize Market Rule 1 as a step forward which should dramatically improve market efficiency, and we agree. The majority of intervenors who addressed this issue were, in fact, concerned not with the merits of the proposal but rather the timing of the implementation.

72. As stated in the CMS/MSS Order, a nodal/zonal approach to pricing, as proposed here, is a reasonable initial approach to congestion pricing. Moreover, the Commission considers the 18-month period before ISO-NE implements fully nodal pricing to be an acceptable period of time to allow for distribution companies to prepare or modify existing data and metering infrastructure. Even if nodal pricing as realized at final NE-SMD implementation is not fully formed at present, the Commission anticipates that New England's congestion pricing scheme will conform thereto at the time of final implementation.

73. The Commission finds that NICC's assertion that NEPOOL could implement nodal pricing for load on a partial basis, because only a small number of parties would elect to participate, to be an unsubstantiated assumption. The Commission defers to NEPOOL's and ISO-NE's expert judgment that the market is not technologically ready for nodal pricing for load.

74. The Commission will deny the request by NES for explicit language limiting ISO-NE's authority to modify market prices to events of "data entry error or failures of market support technology." ISO-NE states in the Joint Answer that Market Rule 1 is actually more restrictive than the provisions in Market Rule 15 and that ISO-NE recognizes that it is constrained by the filed rate doctrine from making unwarranted price changes. Thus, the Commission finds that ISO-NE does not have "unwarranted discretion" to modify prices. Similarly, the Commission will deny NES' request for the publication of detailed data on capacity made ineligible to set the clearing price. In the Joint Answer, ISO-NE and NEPOOL state that ISO-NE is already working to produce "informative data on

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generation that is rendered ineligible to set clearing prices."[50] The Commission finds that this is an appropriate response to NES' protest. Moreover, the Commission encourages ISO-NE to continue this process.

75. The Commission recognizes that NES is, most significantly, objecting to the "retreat" from the Patton Reforms, which the Commission approved in April of this year. We also note, however, that ISO-NE and NEPOOL state that these reforms cannot be implemented now due to problems in integrating the PJM-based software with the design of the new SMD markets, and that ISO-NE and NEPOOL intend to restore these reforms as soon as practicable following the implementation of SMD.[51] The Commission originally accepted the Patton Reforms to allow for a more accurate indication of the value of generation, as well as to provide signals for generation investment. In the interim before the Patton Reforms can be restored, the Commission believes that the adoption a multi-settlement LMP-based system for New England, as proposed in Market Rule 1, will accomplish substantially the same purpose.

76. The Commission will accept ISO-NE and NEPOOL's eligibility parameters. NES asserts that peaking and external dispatchable resources should be automatically eligible to set LMP. In the Joint Answer, ISO-NE and NEPOOL state that peaking units dispatched for energy are eligible to set LMP. As to external transactions, however, the Commission finds that the inability of External Transaction purchases to adjust energy in response to load and/or price changes on a five minute basis justifies their narrower ability to set LMP. With regard to dispatchable load, the Commission will defer to ISO-NE and NEPOOL's technical expertise when they state that "no Real-Time price-sensitive demand is recognized within the Real-Time dispatch software or LMP calculator."[52] The Commission accepts ISO-NE and NEPOOL's explanation that the ex post mechanism is essential to the market design and software as adopted from PJM. We note that the Commission's SMD NOPR proposes the use of ex post pricing insofar as it may encourage bidders to act in a manner consistent with their bids.

IV. FTRs and ARRs

1. NEPOOL'S PROPOSAL

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[50] Joint Answer at 19.

[51] Transmittal Letter at 26.

[52] Joint Answer at 19.

77. ISO-NE proposes a mechanism to manage congestion risk through the use of Financial Transmission Rights (FTRs) and associated Auction Revenue Rights (ARRs). FTRs are uni-directional rights/obligations to collect/pay the difference in the congestion component of the LMP between points of receipt and points of delivery. The registered FTR holder is entitled to receive a share of transmission 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. Each FTR holder can retain the FTR, sell it bilaterally in the secondary market, or sell it in an FTR auction. ISO-NE states that this auction process will enable those users who most value the ability of FTRs to protect against the costs of congestion to procure them. Auctions will initially be held on a monthly basis, and within seven months of the NE-SMD effective date one-year auctions will also begin to be held.

78. ARRs are rights to receive FTR Auction Revenues from the sale of FTRs (other than FTRs sold by FTR holders). ARRs are awarded to congestion-paying entities, transmission customers and Northeast Massachusetts Reliability Region load-serving entities using a four-stage process. Entities paying for new transmission upgrades are also awarded ARRs (Qualified Upgrade Awards, or QUAs). The entity must satisfy the following criteria in order to receive QUAs: (1) the upgrade must increase the transfer capability on the NEPOOL Transmission System, (2) the upgrade must be initially placed in-service on or after March 1, 1997, (3) the cost of the upgrade must be paid for solely by the entity and must not be included in pool-wide rates. ISO-NE proposes to develop by December 31, 2004 a permanent process to replace the current process for awarding QUAs to entities paying for new transmission upgrades.

2. POSITION OF INTERVENORS

79. DENA requests that the Commission condition its approval on ISO-NE's correction of deficiencies in the process for QUA allocation. DENA alleges that there is a lack of clarity and transparency concerning computations used for allocation, data sources, model functionality, qualification standards, disclosure in manuals, and review procedures. NEPOOL and ISO-NE in their joint answer state that the description of the QUA process in Section 8, Appendix C is consistent with the level of detail found in the SMD NOPR, Appendix B, Part II.D.9, and further, that NEPOOL Manual 6 will describe the process for calculating QUAs in detail.

80. FPL is in the process of acquiring Seabrook Nuclear Power Station which includes three high voltage transmission lines. FPL, upon acquisition, will then become

subject to the Seabrook Transmission Support Agreement of May 1, 1973. FPL states that the March 1, 1997 qualification standard to be entitled to ARRs as an entity paying for transmission upgrades is discriminatory and would harm FPL if applied to its proposed acquisition of the Seabrook Nuclear Power Station. FPL argues that the acquisition of the Seabrook facility with upgrades in-service prior to March 1, 1997 obligates them to pay the costs of supporting upgrades while at the same time providing the transmission customers with the benefit of new capacity. NEPOOL and ISO-NE respond to this argument by stating that the purpose of the QUA program is to incent the construction of future upgrades that increase the transfer capability of the NEPOOL transmission grid, and that FPL's request to remove the in-service date eligibility criterion would be contrary to that purpose.

81. Central Vermont argues that Excepted Transactions[53] should be permitted to keep their existing physical contract rights except in cases where the holder exercises the right to ARRs . Central Vermont contends that parties under Excepted Transactions should be allowed to keep existing physical contract rights as long as such rights are not simultaneously held with financial transmission rights.

82. LIPA is concerned that unlike transmission customers receiving in-service, those receiving through and out transmission service will not receive ARRs, since, according to LIPA, through and out transactions are subject to the same transmission rates and congestion charges as internal transactions that qualify for ARRs. LIPA is also concerned with the lack of details provided by ISO-NE concerning ARR allocation and asks for fuller descriptions.

3. COMMISSION RESPONSE

83. The Commission accepts ISO-NE's proposal for FTRs and associated ARRs. In the CMS/MSS Order we generally accepted a similar ISO-NE proposal for FTRs and ARRs.[54] Further, ISO-NE's proposal is consistent with our SMD NOPR, wherein we propose to use financial rather than physical rights.

84. However, we agree with intervenors that ISO-NE's proposal lacks necessary details. It is imperative that ISO-NE be transparent in all of its calculations, procedures,

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[53] An Excepted Transaction is a transmission contract that existed prior to Order No. 888.

[54] CMS/MSS Order, 91 FERC at 62,059.

and review processes. We note that ISO-NE is currently working to develop its operating manuals, which should include much of the detail which intervenors say is lacking. ISO-NE and NEPOOL should work with interested parties to resolve issues as they arise, and ISO-NE must provide useful disclosure in its manuals. We anticipate that at the time that NEPOOL finalizes its manual relating to FTRs and ARRs, it will have resolved the outstanding issues discussed here, and will set forth those resolutions in the relevant manual.

85. Further, with regard to LIPA's assertion that any entity paying transmission congestion charges should be allocated a proportional share of FTR auction revenues, we disagree with the method for allocating ARRs. The proposal would allocate ARRs to "congestion paying entities," defined as a participant or transmission customer that is responsible for paying the congestion costs associated with supplying energy to serve load in New England. In response to LIPA's comments, we do not agree that it is appropriate to allocate ARRs to any entity that pays congestion costs. However, we would expect that parties making a significant contribution to embedded transmission costs through taking long-term (i.e., at least one year) firm service would receive ARRs. We find that entities paying for the embedded costs of the system through taking long-term firm service, including long term through and out transmission service, should be entitled to receive ARRs. We therefore require NEPOOL and ISO-NE, within 30 days, to modify Market Rule 1 to enable all parties taking long-term firm transmission service to receive ARRs, and to remove the provision allocating ARRs to "congestion paying entities."

86. The Commission is not persuaded by FPL's contention that the imposition of the March 1, 1997 qualification standard for QUAs is arbitrary or serves to allocate ARRs in a discriminatory manner. The date marks the effective date of the NEPOOL OATT, and is consistent with NEPOOL's and ISO-NE's purpose of using the QUA process to incent construction of new transmission capacity; it is not unreasonable to disqualify facilities constructed in the 1970's from such awards. FPL has not yet completed its acquisition of the Seabrook-related transmission facilities, and the costs of those facilities are currently included in pool-wide transmission rates and the ARRs for these facilities are properly being allocated by ISO-NE to the transmission customers who are paying for the cost of these facilities. If FPL's acquisition of those facilities necessitates a change in that cost allocation, FPL may make an appropriate filing at that time.

87. With regard to the issue raised by Central Vermont, the Commission's policy is generally not to require abrogation of contract rights, and to allow parties to retain their bargained-for benefits. We therefore require NEPOOL and ISO-NE to remove the

following sentence in Appendix C, 2.1: "Excepted Transactions will not be permitted to use their existing contract rights for physical scheduling of a transaction." This modification is to be filed within 30 days.

V. ICAP

A. Proposal for current ICAP regime

1. NEPOOL'S PROPOSAL

88. The ICAP, or capacity adequacy, market addressed in Section 8 of Market Rule 1 is modeled primarily on the NYISO ICAP market. NEPOOL states that the New York design has several advantages. including eliminating a seam with New York, monthly auctions that allow for a clear assessment of ICAP market value and enable true-ups for load shifting, and less risk of lack of liquidity than a daily market.

89. The proposal includes both summer and winter seasonal ICAP requirements as determined by NEPOOL, with monthly obligation periods. If NEPOOL is unable to determine these requirements by three months prior to the start of the capability year, then the ISO will establish the requirements. NEPOOL proposes to use the UCAP system as is now in place in PJM and NYISO that translates generating capability of ICAP resources into UCAP quantities by taking into account actual unit availability. The total pool responsibility is allocated to each participant seasonally, based on the prior year's coincident peak. While the monthly total pool UCAP requirement remains constant, NEPOOL will adjust participants' responsibilities to take into account any gains or losses of customers.

90. Participants must meet their allocated summer and winter UCAP obligations on a monthly basis by obtaining credits from ICAP units. They can satisfy this obligation several ways, including; bilateral arrangements, self supply, offering interruptible load,

purchases from ISO-NE auctions, or via HQ capacity credits.[55] Participants that fail to meet their UCAP obligation are required to participate in the monthly deficiency auctions. Suppliers of UCAP are obligated to either bid their ICAP resources into the day ahead market (HQ credits do not have to comply with this provision), schedule, or declare to be unavailable an amount of energy equal to the amount of UCAP; other actions are considered "Sanctionable Behaviors" under Appendix B of the proposed market rule.[56] A designated ICAP resource may be scheduled to supply an external transaction, but an equivalent amount of its capacity is subject to curtailment if capacity is needed in NEPOOL. An ICAP resource that is external to the NEPOOL control area also must commit to bid into the day-ahead market if it is dispatchable energy, and must schedule the transaction if it is non-dispatchable energy.[57] NEPOOL has provisions for external ICAP that is either unit-backed, backed by a control area, or HQ credits backed by an emergency arrangement between control areas. Whole resources must notify ISO-NE of the UCAP that they intend to delist on a monthly basis in accordance with NEPOOL manuals. This notification does not excuse the resource from bid requirements in the energy market if it is available.

91. ISO-NE proposes to administer two types of auctions by which participants may procure UCAP, and states that it will provide specifics regarding the auctions in its manuals. It will conduct a monthly UCAP auction to satisfy participant obligations for the upcoming month, with the resulting price also to be used to settle load shifting that occurs during the obligation month. ISO-NE will also conduct a separate deficiency auction prior to the start of the obligation month by which the ISO will procure UCAP for participants that have failed to satisfy their obligations by the time specified. Non-committed resources must be offered at the deficiency auction and the demand at this auction will be the amount of the participants' deficiencies for the upcoming month.

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[55] Capacity Credits that are allocated to parties who make support payments for the Hydro Québec (HQ) Interconnection.

[56] Appendix B allows NEPOOL to impose sanctions for failure of ICAP resources to comply with scheduling, bidding and notification requirements (Appendix B, Sec. 3.1.4). Those sanctions range from $500 per event to $2000 per event (Exhibit 1 to Appendix B).

[57] A dispatchable resource receives hour-by-hour operating instructions from the ISO in accordance with operating procedures and bid or contract quantities, prices, and operating constraints. Non-dispatchable resources are typically self-scheduled and not necessarily dependent on market clearing prices and settlements.

Deficient participants will be charged the clearing price that results from the deficiency auction (the auction is capped at the deficiency rate, and the amount of pool deficiency in MW will not be revealed to suppliers). To the extent that there remains a residual deficiency after this auction, the deficiency will be proportionally divided among deficient participants who will then be charged the deficiency rate ($6.66/kW-month of UCAP) with excess revenue collected by the ISO distributed to all participants.

2. POSITION OF INTERVENORS

92. NES states that the ICAP proposal is an improvement over the existing mechanism and will reduce seams with the neighboring ISOs, particularly the adjusted deficiency charge of $6.66/kW/month.

93. Strategic Energy recommends the Commission reject "any material deviations from its SMD NOPR,"[58] and states that the adoption of the NYISO ICAP model is such a deviation. Strategic Energy asks the Commission to require NEPOOL to work in conjunction with PJM and NYISO in developing a long-term resource adequacy mechanism consistent with the guidelines to be developed in the Commission's SMD rulemaking. Strategic Energy states that implementing Section 8 of Market Rule 1 will be disruptive to LSEs and asks the Commission to set aside the ICAP mechanism until such time as the Commission has fully defined acceptable market design resource adequacy mechanisms.[59]

94. MASSPOWER, a Qualifying Facility (QF)[60] operator, is concerned over the lack of explanation in Market Rule 1 regarding the requirements for QFs to qualify as ICAP Resources, including the quantity of UCAP that the resources would provide. MASSPOWER notes that Manual 20, which is still under development, will contain these provisions, but argues that, since there is no mention of QFs in Section 8, the Commission cannot yet rule on the provisions regarding eligibility of QFs such as MASSPOWER and should therefore defer ruling until it reviews Manual 20.

95. NEPOOL and ISO-NE in their joint answer state generally that the enhanced ICAP arrangements reflect an appropriate near-term resource adequacy mechanism

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[58] Strategic Energy's motion at 5.

[59] Id. at 6.

[60] Qualifying Facilities receive rate and other benefits under the Public Utility Regulatory Policies Act (PURPA).

pending further development, finalization, and implementation of the resource adequacy mechanism in accordance with a final rule in the FERC SMD proceeding.[61]

3. COMMISSION RESPONSE

96. We disagree with Strategic Energy that the ICAP mechanism should be set aside until the Commission's final SMD rule. The ICAP proposal here is an adoption of a regime that is in place in the neighboring control area, NYISO, that provides a reasonable method for ensuring resource adequacy at the present time. Additionally, this reinstates a necessary resource adequacy market in NEPOOL, replacing a void in the electricity market that existed in New England since ISO-NE's original ICAP auction was abandoned in 2000.[62] Additionally, MASSPOWER's request for information regarding the responsibilities and rights of its QF resources should be discussed in the appropriate internal NEPOOL forum to consider development of manuals.

97. The ICAP market proposed here is an improvement over the current mechanism, which was continually undergoing modifications for the past two years. We also note that NEPOOL states that the proposed mechanism is transitional, with a limited life-span pending the outcome of the Commission's SMD proceeding, and that NEPOOL is aware that the SMD NOPR proposes a forward-looking resource adequacy mechanism.[63] This proposal moves in the direction contemplated in the SMD NOPR by incorporating a mechanism that does not rely on a short-term daily market that NEPOOL had in the past, but rather on mechanisms that facilitate longer-term more forward-looking resource acquisition. This is accomplished, in part, with the move to a seasonal obligation. Furthermore, this proposal places New England on the same playing field with New York and will allow both control areas to move in tandem as the Northeast RTO and SMD rule evolve. We thus accept the ICAP mechanism proposed by NEPOOL with the caveats noted below. We also note that, to the extent the ICAP proposal needs to be revised to reflect requirements of the Commission's final SMD rule, that NEPOOL do so in accordance with the time line that will be provided in that rule.

98. The Commission will not accept NEPOOL's and ISO-NE's proposal to distribute the deficiency revenue collected by ISO-NE to be distributed to all participants.

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[61]Joint Answer at 7.

[62]CMS/MSS Order, 91 FERC ¶ 61,311 (2000).

[63]Joint Answer at 25-26.

According to the proposal, ISO-NE will distribute the excess revenue collected by the imposition of ICAP deficiency charges to all Participants by applying the revenues to Schedule 3 of the ISO's tariff (Market Rule 1, Section 8.5.1(c)). This contrasts with PJM where revenues are distributed to compliant LSEs and long capacity owners.[64] We believe that the proposed method does not send the correct signal to deficient participants. We understand that the revenues distributed to deficient participants under this method would be significantly diluted and therefore would have negligible impact when netted against the deficiency rate paid. We do not agree however, that parties that fail to procure their ICAP resources in advance in accordance with the proposed market rule, and therefore, lean on the other participants and jeopardize system reliability, should be rewarded with any share of the revenues. We direct NEPOOL and ISO-NE to modify the proposed market rule so that Participants that are deficient in UCAP and therefore either participate in the deficiency auction or are subject to the Deficiency Charge do not receive any of the revenues generated by applying the deficiency charge. NEPOOL is directed to file these changes within 30 days from the date of this order to be effective with the effective date of the ICAP market.

B. Locational ICAP

1. POSITION OF INTERVENORS

99. NES asserts that NEPOOL's proposal lacks any mechanism that accounts for intra-pool congestion[65] and recommends that the Commission require: (1) deliverability and/or locational reforms; and (2) reforms of common design with NYISO and PJM, to be implemented jointly. NES also recommends that the Commission set a January 1, 2003 deadline for a filing that addresses these concerns. NRG recommends that a locational ICAP requirement similar to that used in NYISO be included in NE-SMD. NRG states that a locational ICAP requirement is a more appropriate mechanism than RMR to send efficient price signals in order to encourage investment in transmission and generation and would eliminate much of the need for RMR. NRG cites the NYISO requirement that LSEs in New York City purchase 80 percent of their ICAP from in-city resources, and

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[64] PJM Interconnection, L.L.C., 95 FERC ¶ 61,175 (2001). PJM revised its Reliability Assurance Agreement to broaden the pool of participants that receive a share of the revenues generated by the deficiency charges to include LSEs that have fully satisfied their UCAP obligations during the period that deficiency charges are assessed, in addition to capacity owners that have satisfied their obligations.

[65] NES' protest at 39.

states that this mechanism provides the proper siting incentive for new generation and for existing generation to remain available. PSEG protests the absence of a locational ICAP source requirement in constrained areas, and similarly argues that no technical obstacles exist to such a requirement. PSEG concedes that, given the present demands associated with NE-SMD issues and in order to allow for a transition, the introduction of locational ICAP could be pushed to January 2004.

100. NEPOOL states in its answer that the issue of locational requirements should be considered in the FERC SMD NOPR proceeding because any mechanism put in place here could be replaced with a mechanism developed in that proceeding.

2. COMMISSION RESPONSE

101. As NEPOOL states in its filing, this is one of the items not adopted from the New York market. NEPOOL simply states in its filing that the zonal requirement implemented by NYISO would be difficult to implement in New England and that NEPOOL intends to develop a more comprehensive solution to the deliverability issue with the goal of extending the concept to the proposed Northeast RTO.[66] The Commission believes that location is an important aspect of ensuring optimal investment in resources, and NEPOOL has not provided sufficient detail as to why a locational requirement would be difficult to implement at this time. Therefore, we direct NEPOOL to develop a locational mechanism together with the other Northeast ISOs as it proceeds with the development of the Northeastern RTO.[67] However, the Commission is also aware that there remain substantial differences of opinion within the industry as to not only the optimal method to ensure that capacity resources are located where it is most efficient but also which method of compensation is most efficient and workable. We also expect that many of these issues be discussed in the Commission's SMD proceeding and that the final rule will identify mechanisms that would be acceptable.

C. Hydro-Québec issues

1. POSITION OF INTERVENORS

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[66]Filing at 21.

[67]For example, locational methods already in use include provisions such as that used by NYISO that ICAP resources be located in certain regions, or that used by PJM whereby ICAP resources have a transmission path to the purchaser.

102. HQUS has concerns over Section 8.3.2(e) of Market Rule 1, which allows HQ Interconnection Capability Credits (HQICCs) to serve as external ICAP, based on an "emergency interchange agreement or other emergency supply agreement" between the NEPOOL Control Area and HQ Control Area over the HQ Interconnection. HQUS states that in Sections 8.3.2 (a) through (d), NEPOOL's filing requires that external ICAP be supported by a generation contract, and that the provision in Subsection (e) is an attempt to fit this model by allowing the HQICCs to serve as external ICAP resources. HQUS objects to the use of HQICCs as ICAP, stating that these should not be considered as ICAP equivalent, and that only ICAP sales over the HQ Interconnection should qualify as external ICAP. According to HQUS, no contract currently exists between the Interconnection Rights Holders (IRHs)[68] and generators in Québec; only NEPOOL is entitled to rely upon the emergency energy provisions under the terms of the Interconnection Agreement, and NEPOOL is not authorized to assign the benefits of the Interconnection Agreement to another party (i.e. to the IRHs). Furthermore, HQUS asserts that the Interconnection Agreement only obliges the Québec Control Area to make energy available if HQ is able to do so: HQ "can exercise its right to commit the [energy] elsewhere in conjunction with firm sales."[69] Thus, HQUS views the HQICCs as less reliable than ICAP.

103. Central Vermont is concerned about provisions in Section 8.3.2(c) of Market Rule 1 that may affect the status of the Vermont Joint Owner Contract (VJO contract), held with Hydro Québec.[70] According to Section 8.3.2(c), non-dispatchable external energy backed by a Control Area must schedule a minimum of 16 on-peak hours during non-holiday weekdays. Central Vermont is concerned that Market Rule 1, as well as the NEPOOL manuals, will alter the treatment of the VJO contract, thus reducing the ICAP credit to 0 MW should it become unavailable during on-peak hours. Central Vermont

[68]The Interconnection Rights Holders pay the support costs of the Hydro Québec Interconnection between New England and Québec.

[69]HQ's motion at 6.

[70]Central Vermont's motion at 7. Central Vermont also refers to its Motion to Intervene Out of Time and Comments of Vermont Joint Owners, filed November 14, 2001, Docket Nos. ER01-2534-000 and ER01-2534-002. In the same intervention, Vermont Joint Owners state that NEPOOL has historically credited, with full ICAP Credit, the long-term capacity and firm energy HQ contracts to meet Vermont Joint Owners' capacity responsibility obligations within NEPOOL.

therefore requests that the Commission find that the VJO contract is excepted from Section 8.3.2(c).

104. NEPOOL states that the arguments raised here by HQUS are virtually identical to those raised in Docket Nos. EL02-61-000 and EL02-70-000 currently pending on rehearing,[71] and to decide these issues in this proceeding would unduly prejudice the rights of parties to those dockets. Regarding the specific issues raised by HQUS, NEPOOL states that HQUS's conclusion that a contract between IRHs and generators in Quebec is required for the HQICCs to qualify as ICAP is misinterpreting Section 8.3.2(e). Rather, NEPOOL states that the HQICCs must be backed by an emergency supply agreement between NEPOOL and Hydro-Quebec,[72] which does exist. The argument as to whether there should be ICCs at all should be addressed in the other referenced proceedings. Regarding the VJO contract, NEPOOL states that the proposed treatment of non-dispatchable external transactions is substantially identical to the treatment of internal generating resources, i.e., a generating resource will lose some of all of its ICAP credit in the event it is partially or fully unavailable. NEPOOL states that the UCAP process in PJM and NYISO functions similarly, and in fact, contracts backed by a control area (like the VJO contract) are held to a less stringent standard than those backed by specific generators.[73] NEPOOL asserts that since the key requirement of UCAP is that it is available when needed at system peak, treatment otherwise would dilute reliability.

2. COMMISSION RESPONSE

105. The Commission has addressed the issue of the HQ Interconnection Capability Credits in a recent order.[74] We note that applicable sections of Market Rule 1 will need

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[71]PG&E National Energy Group, 99 FERC ¶ 61,187 (2002).

[72]Joint Answer at 28.

[73]Control area contracts are granted at full face value credit until they fail to deliver, at which point the UCAP value is reduced. This reduction is less than for a comparable generator, because the interruption for the control area contract is amortized over the total number of hours for the year, compared to the interruption for the generator which is amortized over operating hours. Answer at 29.

[74]PG&E National Energy Group, 100 FERC ¶ 61,227 at P 19-21 (2002) ("Regarding the complaint that all NEPOOL Participants must make generating capacity

(continued...)

to be revised to reflect the outcome of that proceeding. As to Central Vermont's protest regarding the ICAP credits for the VJO contract, we ruled in an earlier order[75] that this contract will continue to be eligible for ICAP credit. However, NEPOOL should not unilaterally make changes to the provisions contained in current market rules relating the treatment of HQ Interconnection contracts when developing its manuals unless directed by the Commission in this or other proceedings.[76]

D. Winter/summer issues

1. POSITION OF INTERVENORS

106. Central Vermont further requests that NEPOOL clarify that winter resource ratings will be used as credits during the winter requirement period and that summer ratings will be used in the summer period. Central Vermont argues that the application of the summer rating against the summer and winter requirements will create an

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[74](...continued)
available to Hydro Quebec in an emergency, although only IRHs will receive the HQ credits, we believe that the HQ credits were established, in part, to recognize the reliability benefits, for both Hydro Quebec and the NEPOOL members, that the financial supporters of the HQ Interconnection provide. . . . With respect to the argument that continuing to provide the IRHs with HQ credits undermines the competitiveness of the NEPOOL market, we disagree. NEPOOL recognized the IRHs' support of the HQ Interconnection and the substantial reliability benefit that the access to generation provides both the New England and Hydro Quebec regions by permitting the NEPOOL Participants Committee to establish and allocate HQ credits after expiration of the Firm Energy Contract in the Restated NEPOOL Agreement").

[75]New England Power Pool, 97 FERC ¶ 61, 213 (2001).

[76]An example of potential changes the Commission may order could include such things as the conversion of capacity credit quantities to UCAP that would be necessitated by the Commission's acceptance of the proposed UCAP mechanism or the adjustment of HQ capacity values in order to reflect actual reliability benefits associated with the HQ interconnection. To the extent that this is accomplished in this or another proceeding by adjusting the value of the HQICCs in order to place these credits on the same basis as other UCAP resources, then it is possible that the current capacity credit amounts may be adjusted.

unreasonable mismatch[77] of resource credits and will transmit distorted price signals. NEPOOL responds to Central Vermont's concerns that it is the intent of the filing that winter unit ratings will be used a credits for the winter period and that summer unit ratings will be used as credits for the summer requirement period.

2. COMMISSION RESPONSE

107. Vermont Participants' issue asking for confirmation that summer and winter unit ratings will be used when determining UCAP credits for the respective seasons was clarified in NEPOOL's answer. We expect that this will be reflected appropriately in NEPOOL's manuals.

E. Delisting

1. POSITION OF INTERVENORS

108. Calpine states that NEPOOL should be required to provide for partial delisting of ICAP resources. According to Section 8.3.4 of Market Rule 1, only whole Resources may be de-listed as ICAP resources. Calpine believes this approach to be discriminatory against large, flexible units, and states that there are no technical or reliability reasons preventing the commitment of "vertical slices" of flexible units.[78] Calpine argues that delisting only whole resources will hamper inter-RTO ICAP and firm energy sales and will create a seam with New York. Calpine states that few resources will delist to engage in external transactions because participants that delist in order to enter into external transactions would incur the opportunity cost of opting out of the NEPOOL ICAP market. Calpine further states that the NE - NY interface may not have the capacity to export the entirety of a resource's output.

109. NEPOOL, in its answer, acknowledges that Calpine’s suggestion may have merit for future consideration, but states that ISO-NE believes that partial delisting of resources would raise issues including which control area has first rights to the resource, which control area has operational control, potential gaming of the market, and physical withholding. NEPOOL states that the proposed ICAP regime is likely to have a limited

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[77]Motion at 8.

[78]Motion at 7. To illustrate the notion of vertical slicing, Calpine uses, as an example, a 500 MW resource: 400 MW could be committed as ICAP to NEPOOL, while 100 MW can serve external load.

life-span; and therefore, the effort spent now on working out these complexities are better spent on other market design issues.

2. COMMISSION RESPONSE

110. We believe that this is an important seams issue and that Calpine has a valid argument. We do not believe that there are technical limitations that would prevent resource owners from allocating resources among several control areas or customers or products. It appears from NEPOOL's answer that this is primarily a seams issue, which is exactly the type of impediment to broad regional markets that the Commission is trying to eliminate. The ability of large generators, in particular, to sell into multiple markets is necessary for a vibrant marketplace, especially regarding ICAP, which experience has shown can be very thinly traded. Restrictions such as this may also discourage investment in large flexible generating units – an undesirable outcome. The Northeast ISOs have entered into a memorandum of understanding that includes principles to facilitate trading of ICAP between the control areas.[79] These principles address commitment, scheduling, call provisions, and curtailment provisions for external ICAP (ICAP transactions that cross control area boundaries). Noting that NYISO recently filed tariff revisions that address this issue,[80] we direct NEPOOL to ensure that principles for external ICAP contained in the MOU are incorporated into the ICAP manual to be in place with the effective date of this ICAP market. We also direct NEPOOL to develop the necessary procedures that allow for the partial de-listing of ICAP resources to be implemented no later than the earlier of the implementation date required in the final FERC SMD rule or the effective date of the Northeast RTO.

F. Discrimination

1. NEPOOL'S PROPOSAL

111. NXEGEN protests certain provisions of the proposed ICAP mechanism that relate to dispatchable load contained in Section 8.3.1(a)(vi) of Market Rule 1 as discriminatory. NEPOOL allows dispatchable load to qualify as ICAP if the participant submits a Demand Bid specifying the price at which it is willing to be interrupted. NXEGEN

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[79] See http://www.isomou.com, a Memorandum of Understanding (MOU) between ISO-NE, NYISO, PJM, and Independent Electricity Market Operator (IMO) Ontario.

[80] 100 FERC ¶ 61,122 (2002).

argues that demand resources should receive the same treatment as generators that provide ICAP, i.e. "a capacity payment for the ICAP they provide as well as an energy payment for actual curtailment performance" and that not doing so discriminates against demand resources.

2. COMMISSION RESPONSE

112. NXEGEN appears to miss the point of the resource adequacy market. LSEs are required to cover their obligations and have several mechanisms to accomplish this requirement, including purchase and self-supply. Load, or the demand side, is one resource that LSEs are able to tap to satisfy this obligation; owning a generating unit is another. As with other products, self-supplying one's own needs does not warrant compensation. For the foregoing reasons, we reject the claim made by NXEGEN and rule that the treatment of interruptible load in the proposed ICAP market is not discriminatory. (The Commission does note, however, that an LSE should be able to sell or trade its UCAP credits from demand-side resources to other parties, provided that the actual credits are verifiable by the ISO.)

G. Auctions

1. POSITION OF INTERVENORS

113. Braintree contends that the NE-SMD filing fails to establish that its capacity auctions proposal will be sufficiently competitive to result in just and reasonable prices. Braintree argues that, because of long supply periods and high concentration of generation ownership, capacity auction markets are vulnerable to the exercise of market power and price fixing. Pointing to past experience in both NEPOOL and PJM with capacity auction markets, as well as limited market monitoring provisions contained in this filing, Braintree calls for the proponents of Market Rule 1 to provide evidence that the capacity auctions will be dependably capable of producing just and reasonable prices.[81] In responding to Braintree's concern, NEPOOL points to the fact that the proposed mechanism is modeled after New York, which has not experienced unworkable

[81] Motion at 8.

market power problems. In justifying its proposal, NEPOOL also points out that New England has more excess capacity than New York, is proposing a single pool-wide ICAP market (as opposed to NYISO's locational market), and that ISO-NE's market monitoring unit will detect possible market power problems and act appropriately.

3. COMMISSION RESPONSE

114. We view Braintree's concerns regarding the auction process as unfounded, since this market design uses the NYISO approach that does not include a daily auction, and prior competitive problems were experienced primarily in the daily market for ICAP. The use of longer term contracts and supply periods will also further reduce the need to rely on the monthly auction and the deficiency auction, so that only a small percentage of the pool ICAP requirement will be satisfied in the short-term auction. The elimination of market constraints due to control area seams, some of which are addressed here (including the delisting of resources and the MOU between the ISOs), as well as the Northeast RTO proceeding which should further reduce seams and deal with the issue of integrating the HQ Interconnection into RTO tariff, will together ensure that a greater number of market participants will be trading ICAP than would be the case if NEPOOL's ICAP market continued to operate in isolation. The charge assessed against participants who fail to meet their ICAP responsibilities, which is based on the replacement cost of a new unit, will also serve as a de facto price cap on ICAP. Finally, we stress that NEPOOL's market monitor must be vigilant to ensure that market power is not exercised in the ICAP market, and we will further expect parties who perceive possible exercises of market power to bring those concerns to the market monitor in timely fashion.

H. Docket No. EL00-62-039

115. Finally, the Commission will take the opportunity presented by this filing to dispose of a pending case which is now moot. On December 3, 2001, in response to an order issued by the Commission on August 28, 2001,[82] ISO-NE filed a compliance report docketed as EL00-62-039 regarding alternatives to the ICAP requirement. ISO-NE's filing served as a status report that identified reforms that ISO-NE was considering to the current ICAP market as well as a concept for a forward reserve market in the future. The report proposed to implement the identified improvements to the ICAP market concurrently with its NE-SMD filing addressed in this order.

116. The NE-SMD filing effectively renders the December 3, 2001 compliance filing as moot. Further, these changes to New England's ICAP regime will synchronize the

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[82] ISO New England, 96 FERC ¶ 61,234 (2001).

NEPOOL ICAP market with that of New York, which we consider particularly important since the two control areas will be working to eliminate remaining seams issues as they pursue their RTO filing. Having the market in New York and New England on the same standard at this point will allow both control areas to move forward together to implement any changes to the resource adequacy market if directed by the Commission's final SMD rule, and the Commission therefore dismisses the December 3, 2001 filing as moot.

VI. DSM programs

1. NEPOOL'S PROPOSAL

117. NEPOOL's Market Rule 1, Appendix E offers a demand side management plan to reduce consumption during peak periods which is available to power marketers, competitive energy suppliers, utility companies, and other NEPOOL Participants that encourage retail customers to reduce consumption during peak demand periods. NEPOOL's demand side management plan consists of five programs. The Day-Ahead Demand Response Program allows participants to submit offers, subject to a \$50/MWH minimum and a \$500/MWH maximum, at which they would curtail consumption. The Real-Time 30-Minute Demand Response Program provides the maximum of the zonal price or \$150/MWH for a minimum of two hours to units that interrupt load within 30 minutes. The Real-Time Two-Hour Demand Response Program provides the maximum of the zonal price or \$100/MWH for a minimum of two hours to units that interrupt load within two hours. The Real-Time Price Response Program pays the maximum of the zonal price or \$100/MWH when a participant voluntarily reduces consumption during the eligibility period when the day-ahead or in-day market forecasted prices are greater than \$100/MWH. The Real-Time Profiled Response Program, which is intended to appeal to residential and commercial customers, pays the maximum of the zonal price or \$100/MWH to participants whose loads are interrupted upon the demand of ISO-NE. For each of the five programs, participants are required to provide measurement results demonstrating the extent of curtailment; with two exceptions, these measurements must be performed through interval metering.

2. POSITIONS OF INTERVENORS

118. Both NICC and NXEGEN request that the demand side management plan be expanded to include more parties. NICC asks that end-users that are governance-only members of NEPOOL be allowed to participate. NEPOOL and ISO-NE state in their answer that there are only five NEPOOL end-user members that voluntarily took an

election to not become NEPOOL Participants but instead became governance-only members;[83] if these end-users change that election, they would become eligible to participate in the demand side management plans. NXEGEN suggests granting eligibility, through a certification process, to non-NEPOOL members who provide curtailment services to NEPOOL customers. NEPOOL states that it has requested the NEPOOL Membership Committee consider extending membership to providers of curtailment services to customers. NXEGEN also requests that the sunset date of the demand side management plan be moved from 2004 to 2006 in order to encourage greater participation.

119. A number of protests request modifications to the dollar-level floors and ceilings in the programs. Both NICC and Strategic Energy protest the maximum $500/MWH constraint in the Day-Ahead Demand Response Program. They claim that demand side resources should be entitled to the same maximum as supply side resources, which are subject to a $1000/MWH maximum. NEPOOL justifies this disparity in its answer by stating that the supply side and the demand side are not subject to the same rules: generators can be ordered on-line in real-time if needed, but demand side resources cannot be ordered to curtail in real-time.[84] NXEGEN argues that the Real-Time Demand Response Programs minimum amounts of $150/MWH and $100/MWH for the 30 minute program and the 2 hour program, respectively, are too low to encourage wide participation in demand side management programs. NEPOOL states that these minimum prices represent guarantees and that the benefit of such guarantees are not offered to generating facilities. NXEGEN also requests the elimination of the $50/MWH floor for the Day-Ahead Demand Response Program and the $100/MWH floor for the Voluntary Price Response Program. NXEGEN states that the floors prevent fuller participation in demand side management programs and thus limit investments in facilities that could provide peak demand relief. NEPOOL responds that the demand side management programs are designed to attract curtailments during peak demand periods and that the minimum floors have been set at levels that NEPOOL Participants consider to be the minimum price that would encourage customers to reduce consumption during peak demand. In addition, NEPOOL state that other instruments are

[83]Governance-only members, among other things, are not required to fulfill certain reporting and dispatch obligations and are exempt from certain expenses.

[84]A generator that is not accepted in the Day-Ahead market may still be ordered on-line in Real-Time. However, a Day-Ahead demand resource not cleared in the Day-Ahead market cannot be ordered to curtail in Real-Time.

offered, such as demand bids or decrement bids, for those participants who wish to interrupt their load at a lower price than the demand side management plan minimums.

120. NICC states that greater price certainty is needed to encourage demand resources to participate. It asks that demand side resources be allowed to submit multi-part bids specifying minimum down times and start-up costs. NEPOOL has acknowledged in its answer that the multi-part bid request is reasonable and that it will investigate its feasibility. NEPOOL is concerned, however, that multi-part bid features be consistent with the Commission's SMD NOPR proposals requiring that start-up costs and minimum curtailment times be submitted as part of load's demand bids. NICC also requests that customers with accounts in multiple load zones be allowed to participate on an account-by-account basis. NEPOOL replies that aggregated resources must be from the same zone, because costs and prices are allocated on a zonal basis, but that resources do not have to be aggregated as long as they surpass minimum size loads. Strategic Energy encourages greater price certainty by permitting large demand side resources to receive nodal prices.

121. NXEGEN requests other additions to the current demand side management plan. NXEGEN asks that participants be allowed to use alternative measurement devices to interval metering, claiming that the use of multiple alternative measures to interval metering may broaden the base of demand resources, reduce costs, and encourage new technology. NEPOOL responds to this comment by asking that these devices be more fully described and presented for discussion within NEPOOL. NXEGEN also recommends expanding the program to include Real-Time Demand Response Programs with less than 30 minutes of lead time. NEPOOL's answer is that such a program in not currently necessary and that communication technology for this program is not yet available.

3. COMMISSION RESPONSE

122. The Commission accepts NEPOOL's proposal for the demand side management plan. No party objects to the overall implementation of the programs presented and the Commission's SMD NOPR encourages development of these programs.

123. The Commission requires NEPOOL to change the eligibility requirement in their Appendix E, Section 1.1 and to file this change within 30 days. The new eligibility requirement should provide that any party that can curtail its own use or provide curtailment services is eligible to participate in the demand side management plans. The

market's ability to respond to peak demand periods will be increased with increased numbers of demand side resources. The Commission denies NXEGEN's request for a later sunset date; NEPOOL's proposed date of December 31, 2004 provides sufficient time for participants to experience the Market Rule 1's demand side management plan.

124. The Commission accepts NEPOOL's responses to issues concerning dollar-level floor and ceilings. The Commission finds that the arguments presented by NEPOOL are reasonable. Generally, it is our view that generation resources and demand resources should be treated identically with regard to dollar-value floors and ceilings, so as to encourage both sides to contribute to demand side management. If, however, a resource can curtail immediately or quickly, that resource will be of more value to the system than a resource that must curtail more slowly, and it is thus reasonable to provide greater economic incentives to a more valuable resource to participate in New England demand management programs. The demand side management plan is intended as an incentive program, however, and as such, if later experience demonstrates portions of it to be ineffective, the Commission encourages NEPOOL to file to modify the dollar-value floors and ceilings in its Market Rule 1.

125. The Commission agrees with NEPOOL's concern regarding multi-part bids, and we will not require NEPOOL to implement this aspect prior to the release of the Commission's final SMD rules. The Commission agrees that aggregated resources must be in the same zone because costs and prices are allocated on a zonal basis. The Commission also accepts NEPOOL's use of zonal pricing for all loads until the time NEPOOL are capable of completing a move to nodal pricing for all loads.

126. The Commission will not require NEPOOL to implement new technology for curtailment measurement and communications at this time. However, we strongly encourage all parties to collaborate in the development and implementation of new technology in the demand side management plan. The NEPOOL stakeholder process should serve as a forum for the discussion of issues prior to their submission to the Commission. The Commission believes that these issues are best presented and debated within the NEPOOL process as they arise.

VII. Reserves

1. NEPOOL'S PROPOSAL

127. The NE-SMD proposal does not include separate bid-based Operating Reserve markets similar to NEPOOL’s existing three Operating Reserve markets. ISO-NE and

NYISO have a reserve sharing agreement in place, and NEPOOL and ISO-NE are coordinating with PJM in the development and implementation of a new ten-minute spinning reserve market, expected to be operational in NE-SMD in 2003. However, to reflect the fact that units relied upon by the ISO for Operating Reserves are effectively compensated by ensuring the recovery of their as-bid costs, the former terminology of Net Commitment Period Compensation has been changed to Operating Reserve costs. Under Section 3.2.3(b) of Market Rule 1, Resources providing Operating Reserve will receive credits equal to their lost opportunity costs designed to ensure that such units receive at least what they would have if they were scheduled in the Day-Ahead Energy Market.

2. POSITION OF INTERVENORS

128. DENA and NES find the loss of reserves markets a step backwards. They state that market bidding sends the right market signals, creates incentives for investment, and encourages resources to be more flexible. NES further states that Market Rule 1 pays resources whose bid exceeds available market revenue an Operating Reserve payment based on a formula that will only allow these reserves resources to receive meaningful compensation (which compensation will be in the form of socialized uplift charges, which distort LMP). NES point to the current lack of reserve resources, particularly peaking capacity, as evidence for the requirements for reserves markets, noting that a true hourly reserves market provides incentives that make the system more efficient and reliable.

129. NES finds ISO-NE's proposal to implement a spinning reserves market in early 2003 an inadequate gesture. It notes that the SMD NOPR would require a separate market for each of the types of operating reserves it procures. NES notes that a single spinning reserves market provides no incentive to develop peaking units, of which ISO-NE has few. NES additionally finds the PJM model for reserves, designed around the resources and needs of the PJM markets, a poor match for the operational requirements of ISO-NE. NES states that only hourly markets for all resources needed to meet reliability requirements, if paid a transparent clearing price, will efficiently capture the inherent value of reserve service. NES further remarks that such reserve markets should have as a goal compatibility with the New York markets.

130. NUSCO notes ISO-NE's commitment to implement a TMSR market in 2003 and requests the Commission to order ISO-NE to integrate both spinning and non-spinning reserves markets as effective in NYISO within six months of the implementation of the

NE-SMD in ISO-NE. NUSCO states that NYISO is a natural trading partner and this would eliminate a seam issue with NYISO.

131. NEPOOL and ISO-NE answer that Operating Reserve markets cannot be implemented in the initial NE-SMD rollout without unacceptable delay or risk. PJM's platform, upon which NEPOOL and ISO-NE base the NE-SMD proposal, does not include separate bid-based markets for either spinning or non-spinning reserves. Operating Reserves are effectively compensated by ensuring the recovery of their as-bid costs using NEPOOL and ISO-NEs former terminology of Net Commitment Period Compensation (now referred to as Operating Reserve costs) which is consistent with PJM terminology.

132. NEPOOL and ISO-NE submit that bid-based Operating Reserve markets will be developed to conform with the final rule arising out of the Commission's SMD NOPR process. The NE-SMD Filing explains the current efforts by PJM, (coordinated with ISO-NE) to develop a bid-based spinning reserve market. NEPOOL and ISO-NE state that the market design for ten-minute spinning reserve in New England is complete and the dispatch software has been developed. Only the further development of the necessary settlement software remains to be completed. NEPOOL and ISO-NE continue to expect the roll-out of this new spinning reserve market to be undertaken in 2003. This initiative continues to be a high priority and, depending upon the final market design arising from the Commission's SMD NOPR, may soon include efforts for the development of further bid-based markets for supplemental reserves.

133. NEPOOL and ISO-NE state there is no reason for the Commission to impose arbitrary deadlines when an initiative is already underway to implement spinning reserve market improvements far in advance of the deadlines the Commission is expected to impose on the rest of the nation under RM01-12-000. Requests for arbitrary deadlines at this time should be rejected in favor of an acknowledgment of existing efforts which will be achieved as expeditiously as feasible.

134. Central Maine objects to the socialization of costs associated with operating reserves necessary to provide VAR support[85] in specific localities. Central Maine

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[85]In order to maintain transmission voltages on the system within acceptable limits, generation facilities are operated to produce (or absorb) reactive power (VARs). Thus, Reactive Supply and Voltage Control from generation must be provided for each transaction on the transmission System. The amount of Reactive Supply and Voltage (continued...)

requests that the Commission reject Sections 3.2.3(d) and 3.2.3(h) of Market Rule 1 and require ISO-NE to allocate such costs to the parties that cause or benefit from the VAR support. Central Maine states that socialization should only be allowed when provision of VAR support is required to support the reliability of the system as a whole.

3. COMMISSION RESPONSE

135. Intervenors assert that the loss of reserve markets will have a negative impact on LMP and will diminish the price signals that serve as an incentive to plan and build appropriate resources. However, intervenors do not oppose the implementation of the NE-SMD with the attendant gains of a multi-settlement market, LMP, and congestion management in order to maintain existing reserves markets. They request the Commission to order ISO-NE to develop and make effective additional reserve markets within six months of implementation of Market Rule 1. ISO-NE and NEPOOL state that, as a matter of priority, they had to postpone the development of bid-based reserves markets in order to implement the NE-SMD with its attendant gains. The Commission finds ISO-NE and NEPOOL's answer persuasive. Whatever negative result this represents, we see the NE-SMD proposal as a significant step forward. We note and take encouragement from ISO-NE's commitment to implementing a spinning reserves market in 2003 and other reserves markets as result from the final rulemaking in RM01-12-000. We agree with NEPOOL, ISO-NE and the intervenors that the development of reserve markets are a high priority. We encourage ISO-NE to keep compatibility with the NYISO markets as a goal when developing reserves markets. We concur with ISO-NE and NEPOOL that it is premature to order additional markets to be developed without the certainty of the requirements of the Commission's SMD rulemaking, and therefore will not order additional reserves market development at this time.

136. With regard to the issues raised by Central Maine, VAR support is required for any transmission of power. Requirements can vary by events on the system that are normal and local, such as the import of significant amounts of lower-priced power from a neighboring system, or outages of major generators in other localities resulting in the loss of reactive sources and increase in transfer of large amounts of replacement power. Additionally, insufficient reactive support in one area may make demands on another.

[85](...continued)
Control that must be supplied will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region.

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Finally, during low load periods, line and cable charging may produce high voltages such that shunt reactors are connected to provide VAR support. NEPOOL procedures establish acceptable ranges for load power factors to maintain reliable system VAR. Transmission providers are expected to monitor and manage power factor, adding or removing reactive resources to achieve acceptable tolerances. Thus, VAR support is an essential element in maintaining efficient transmission of power over the grid. We find Central Maine's request to require local allocation of VAR support costs to lack specific support and to be without merit. We find that VAR support is required to maintain the stability and efficient operation of the grid and allocation of costs as outlined in Schedule 2 of the NEPOOL OATT[86] is appropriate.

VIII. Regulation service

1. NEPOOL'S PROPOSAL

137. ISO-NE proposes to credit generators providing regulation service the higher of (1) the Regulation Clearing Price (expressed in megawatt-dollars) times the assigned regulating capability, or (2) the generator's Regulation Supply Offer times the assigned regulating capability, plus the real-time opportunity costs per MWH of capability.

2. POSITION OF INTERVENORS

138. NUSCO finds the current method of compensating generating facilities for providing regulation service, which pays an availability payment and a variable amount in accordance with the actual regulation movement, superior to the proposed settlement in Market Rule 1. NUSCO states that under Market Rule 1, a facility selected to provide regulation service will receive payment for availability but not be compensated for services actually performed.

139. ISO-NE and NEPOOL jointly answer that NUSCO is correct in that Regulation movement-based payments are not included in Market Rule 1. They state that the Regulation Service provisions within Market Rule 1 are based on the PJM rules and software, and will therefore expedite the cost-effective implementation of a multi-settlement and congestion management market design in New England.

3. COMMISSION RESPONSE

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[86] $CH = (CC + LOC + SCL + PC)\ \dfrac{HL_1 + RC_1}{HL + RC}$

140. We direct NEPOOL and ISO-NE to file a clarification within 15 days explaining in greater detail why it proposes no longer to use the ISO-NE former pricing mechanism, which included payments for actual regulation movement (ramping).

IX. Emergency energy

141. Market Rule 1 proposed that the allocation of costs or credits resulting from the purchase or sale of Emergency Energy be based on the Real-Time Load Obligation Deviation. Real Time Load Obligation refers to the MWH obligation (including External Transaction sales) a participant has at a particular location and hour. If there exists a difference between the Real-Time and the Day-Ahead Load Obligations, that is measured and referred to as the Real-Time Load Obligation Deviation. National Grid argues in its intervention that the allocation of costs 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. In their Joint Answer, the NEPOOL Participants Committee and ISO New England agree with National Grid and declare their intention to incorporate the revision into any Commission-required compliance filing.

142. The Commission notes that, in footnote 4, page 8, of its intervention, National Grid speculates that the same flaw it 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 seeks clarification on whether this should be Real-Time Adjusted Load Obligation Deviation. The Commission directs ISO-NE and NEPOOL, within 30 days, either to modify the tariff as suggested by National Grid, or else to file a statement as to why the proposed method is superior.

X. Infrastructure upgrade costs

143. The Maine Commission ask the Commission to ensure that the costs of transmission upgrades do not continue to be socialized across the pool, as has previously

been the case. It points out that in a prior order, the Commission found that continued socialization of the cost of transmission upgrades might become inappropriate once LMP was implemented, and it ordered NEPOOL to make a filing under Section 205 or 206 to propose a cost allocation methodology "consistent with an LMP scheme."[87] The Maine Commission points out that NEPOOL and ISO-NE have not proposed a new cost allocation methodology, and asks the Commission to order them to do so. NUSCO, on the other hand, asserts that transmission upgrades benefit all NEPOOL participants by reducing the effect of congestion and market power, and therefore asks the Commission to approve the retention of socialization of transmission upgrade costs that currently exists in NEPOOL's filing.

144. The Commission will grant the Maine Commission's request. Now that NEPOOL is implementing LMP, parties will be able to see more readily which areas would most benefit from transmission upgrades, and what party or parties will most benefit. It is therefore appropriate to require those parties to bear the costs of these new upgrades. NEPOOL has in fact stated that it anticipates eliminating the socialization of the costs of transmission upgrades to provide for a mechanism for cost allocation for transmission upgrades that is consistent with LMP.[88] As we have previously stated in our CMS/MSS orders, we will require ISO-NE to develop a mechanism which, in situations where the parties cannot agree as to who benefits from the upgrade,[89] provides an objective, non-discriminatory default cost allocation mechanism that is consistent with the principles of cost causation.[90]

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[87]ISO New England, 100 FERC ¶ 61,029 at P 8 (2002) ("The Commission . . . finds that the interim default cost allocation mechanism for transmission cost upgrades should be reviewed when LMP in New England is proposed, but in an appropriate Section 205 or Section 206 proceeding. We agree that continuation of NEPOOL's socialized cost allocation methodology may be inappropriate once LMP is implemented . . . . Accordingly, we will require ISO-NE and/or NEPOOL to propose a revised default cost allocation methodology in ISO-NE's or NEPOOL's SMD filing consistent with an LMP scheme").

[88]See Transmittal Letter at 3, fn. 5.

[89]I.e., either parties cannot agree that the upgrade benefits the entire system, so that its costs should be socialized across the pool, or parties cannot agree as to which specific party or parties benefit from the upgrade and so should bear all the costs.

[90]See ISO New England, 98 FERC ¶ 61,173 at P 59 (2002).

XI. Manuals

145. NEPOOL has not yet finalized the manuals which will accompany Market Rule 1. EPSA states that Market Rule 1 does not expressly state that those provisions of those manuals which have a "substantial effect on rates, terms and conditions of service" are filed with the Commission. DENA, NSTAR and Central Vermont also point to this as a possible problem. Calpine and EPSA make a similar assertion, and also argue that "to the degree the ISO is given any discretion in determining which items are administrative or procedural versus those affecting rates, then the NEPOOL governance process must be modified to allow for stakeholder appeal of that decision."[91] DENA and NES ask the Commission to require that all the manuals be filed, and Central Vermont asks that the Commission require that all manuals be approved by the NEPOOL Participants Committee and be submitted to participants, to enable them to submit comments on the manuals to the Commission before NE-SMD is implemented. In addition, several parties have raised concerns that NEPOOL will only address particular issues important to them (for example, Braintree's concern regarding ICAP auctions) in its manuals, and thereby deprive them of the ability to contest that issue before the Commission.

146. ISO-NE states in its answer that it is opposed to a requirement that it file each manual. It states that it needs to retain the flexibility to modify the manuals promptly to the extent necessary to coordinate change with the PJM market design.

147. The Commission agrees that NEPOOL should insert language in its tariff stating that provisions which have a "substantial effect on rates, terms and conditions of service" are filed with the Commission, and we order NEPOOL to modify Market Rule 1 to this effect within 30 days. We will not, however, require the filing of the manuals at this time. We do not require PJM to file its manuals.[92] We are also mindful of ISO-NE's need for flexibility to modify manuals as needed. Nor will we require a special appeals process to enable participants to appeal ISO-NE's decision to place material in a manual

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[91]Calpine motion at 3-4.

[92]See Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257 at 62,242-43 (1992) ("We will not require [PJM] to file the PJM Manuals or any subsequent changes to the PJM Manuals. The PJM Transmission Tariff and rate schedules define the rates, terms and conditions of jurisdictional services provided by PJM, not the PJM Manuals . . . Any reference to the specific rates, terms and conditions that are found in the PJM Manuals should be set forth in the tariff or rate schedule as well").

rather than in its tariff. NEPOOL has stated that all manuals will be reviewed and voted on by at least two NEPOOL Committees, and we encourage NEPOOL members to participate in this stakeholder process to ensure that their concerns are considered. If members wish to appeal NEPOOL decisions regarding manuals, they may use NEPOOL's current internal dispute resolution procedures under the NEPOOL Agreement prior to filing a complaint with the Commission.

XII. Timetable for future enhancements.

148. The Commission agrees with the statements by intervenors, NEPOOL and ISO-NE that many desirable elements of the market are still missing from Market Rule 1. ISO-NE and NEPOOL explain that within the time and resources available, the filed Market Rule 1 encompasses the limits of what can be implemented at this time. Missing from the market design at this time are a full range of reserves markets, ICAP improvements including locational/deliverability requirements, full nodal pricing, and the remaining Patton Reforms.

149. We are aware of the uncertainty resulting from the Commission's issuance of the SMD NOPR vis-a-vis ISO-NE's NE-SMD filing. We note ISO-NE's commitment to implement market enhancements as soon the requirements of the final rule in RM01-12-000 are known and can be developed. We accept that commitment and require NEPOOL and/or ISO-NE to make progress reports every 90 days as to their progress in implementing these reforms.

The Commission orders:

(A) NEPOOL's and ISO-NE's filing is accepted, with the modifications described above, effective as of the dates requested.

(B) NEPOOL and ISO-NE are required to provide additional support for the first level of their mitigation plan, as described above, within 15 days of the date of this order.

(C) NEPOOL and ISO-NE are required to file the other modifications and clarifications described above within 30 days of the date of this order.

(D) 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.

(E) NEPOOL and ISO-NE must notify the Commission as they implement the milestones of NE-SMD discussed in paragraphs 21 through 23 above.

(F) Docket No. EL00-62-039 is dismissed as moot.

By the Commission. Commissioner Brownell dissented in part with a separate statement attached.

(S E A L)

Magalie R. Salas,
Secretary.

APPENDIX:

The listed parties have filed notices of intervention or motions to intervene in Docket No. ER02-2330-000. Short-hand references to parties referred to in the order are indicated in parenthesis after the name. Late interventions are indicated by an asterisk.

Company Name

American National Power (ANP)
Bangor Hydro
Braintree Electric Light Department, Reading Municipal Light Department, and Taunton Municipal Lighting Plant (Braintree)
Calpine Eastern Corporation (Calpine)
Central Maine Power Co. (Central Maine)
Central Vermont Public Service Corporation and Vermont Electric Co. (Central Vermont)
Connecticut Attorney General (CTAG)
Connecticut Municipal Electric Energy Cooperative (CMEEC)
Connecticut Office of Consumers Counsel (Connecticut OCC)*
Constellation Power Source, Inc. (Constellation)
Dominion Companies (Dominion)[93]
Duke Energy North America LLC and Casco Bay Energy LLC (DENA)
Dynegy Power Marketing, Inc. (Dynegy)
Electric Power Supply Association (EPSA)
El Paso Merchant Energy LP (El Paso)
FPL Energy LLC (FPL)
HQ Energy Services (HQUS)
Long Island Power Authority (LIPA)
Maine Public Utilities Commission (Maine Commission)
Massachusetts Department of Telecommunications and Energy (MDTE)
Massachusetts Municipal Wholesale Electric Company (MMWEC)
MASSPOWER and Pittsfield Generating Co. (MASSPOWER)*
National Grid USA (National Grid)

[93]Dominion Resources Services, Inc., Dominion Nuclear Connecticut, Inc. (Dominion Connecticut), Dominion Nuclear Marketing, I (DNM1), Dominion Nuclear Marketing, II (DNM2), Dominion Nuclear Marketing, III (DNM3), Dominion Energy Marketing, Inc. (Dominion Marketing) and Virginia Electric and Power Company (Dominion Virginia).

NEPOOL Industrial Customer Coalition (NICC)
New England Conference of Public Utility Commissioners (NECPUC)
New England Renewable Power Producers Association (NERPPA)
New England Suppliers (NES)[94]
New Hampshire Public Utilities Commission (New Hampshire Commission)
Northeast Utilities Service Company[95] and Select Energy, Inc. (NUSCO)
NRG Companies[96] (NRG)
NSTAR Electric and Gas Corporation (NSTAR)
NXEGEN, Inc. (NXEGEN)
PSEG Power LLC and PSEG Energy Resources & Trade LLC (PSEG)
Reliant Resources, Inc.
Strategic Energy LLC (Strategic Energy)
Trans-Canada Power Marketing, Ltd. (TCPM)*
United Illuminating Co. (UI)
Vermont Department of Public Service (VDPS)
Vermont Public Power Supply Authority (VPPSA)
Waterside Power LLC (Waterside)

[94]Subsidiaries of AES Londonderry, PG&E National Energy Group, Sithe, and Wisvest.

[95]On behalf of Connecticut Light and Power Company, Western Massachusetts Electric Company, Holyoke Water Power Company, Holyoke Power and Electric Company, and Public Service Company of New Hampshire (collectively, the NU Operating Companies).

[96]NRG Power Marketing, Inc., Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, and Somerset Power LLC.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool and ISO New England, Inc. — Docket No. ER02-2330-000

ISO New England, Inc. — Docket No. EL00-62-039

(September 20, 2002)

BROWNELL, Commissioner, dissenting in part

1. It has been over two years since ISO-New England and the market participants commenced redesign of the ISO-New England's administered markets. During that time, the Commission issued papers on its vision of a standard market design, held several conferences, and received comments on many of the issues contained in ISO-New England's proposed market redesign. While I support many of ISO-New England's proposed market redesign changes, I cannot at this time support the proposed installed capacity market. I agree that the proposal represents an improvement over the existing installed capacity mechanism and in the past I have supported such interim improvements so as not to disrupt New England's efforts toward building better markets and products, including resource adequacy. However, I believe that to perpetuate an installed capacity product that fails to encourage long-term resource investment and ignores the deliverability of resources that receive installed capacity payments misses the fundamental goal which is to ensure adequate, deliverable resources and thus reliability on a going-forward basis. Moreover, I believe that at this juncture with the potential formation of a Northeast RTO, market participants should focus on building a better, seamless market. For these reasons I respectfully dissent.

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Nora Mead Brownell

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