



October 28, 2005

**Via Hand Delivery**

Honorable Magalie R. Salas, Secretary  
Federal Energy Regulatory Commission  
888 First Street, NE  
Washington, D.C. 20426

**Re: ISO New England Inc. and New England Power Pool,  
Docket No. ER06-\_\_\_\_-000;  
Interim Amendments to Market Rule 1 for Winter 2005/2006**

Dear Ms. Salas:

Pursuant to Section 205 of the Federal Power Act (“FPA”),<sup>1</sup> ISO New England Inc. (the “ISO”) and the New England Power Pool Participants Committee<sup>2</sup> (“NEPOOL”) hereby jointly submit an original and six (6) copies of this transmittal letter and the interim revisions to Market Rule 1<sup>3</sup> attached hereto (the “Winter Package”)<sup>4</sup> to aid the ISO in implementing its Winter 2005/2006 Action Plan (as defined below). In order to obtain the full benefits of the Winter Package for the targeted period, the ISO and NEPOOL request expedited consideration of the Winter Package, a shortened comment period of 14 days, and its acceptance with an effective date of December 1, 2005.<sup>5</sup> The

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<sup>1</sup> See 16 U.S.C. § 824(d) (2005).

<sup>2</sup> Capitalized terms used but not defined herein are intended to have the meanings given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the “Tariff”), the Second Restated New England Power Pool Agreement, or the Participants Agreement.

<sup>3</sup> Market Rule 1 is Section III of the Tariff.

<sup>4</sup> The Winter Package consists of proposed revisions to Market Rule 1 and Appendices A, E and F thereto, and the inclusion of a new Appendix I to address: (a) generator offer flexibility; (b) the elimination of allocation of Real-Time NCPC deviation charges to Emergency Energy Transactions (“EETs”); (c) posturing rules; and (d) the addition of a demand response supplemental incentive program.

<sup>5</sup> As discussed in Section V below, the ISO and NEPOOL Participants Committee request waiver of the 60-day notice requirement of 18 C.F.R. § 35.3(a) (2005).

rule changes included in the Winter Package will automatically “sunset” on March 31, 2006.<sup>6</sup>

The Winter Package is designed to enhance the reliability of New England bulk power system operations during the coming winter, in which natural gas and other generating fuels may be in short supply due to hurricane damage in the Gulf of Mexico region. More specifically, implementation of the Winter Package will serve the public interest by providing several mechanisms to potentially increase the availability of generating capacity during periods in which generating fuel supplies become scarce. Further, the Winter Package will complement Appendix H to Market Rule 1,<sup>7</sup> which also specifies actions to increase system reliability during cold weather conditions.

The ISO emphasizes that it is difficult to predict at this time the amount of natural gas supply that will be available to New England during the coming winter months. Nor is it possible to predict with any reasonable certainty whether extreme cold weather will develop that could operate in tandem with gas or fuel-oil shortages to create electric energy shortages in New England. Nonetheless, based on the facts and projections currently available, it is prudent to take the steps reflected in the Winter Package to prepare for contingencies, in the event that they materialize.

Understanding of the impact of the hurricanes on future gas supply is still evolving and the Winter Package of necessity was completed on a highly accelerated basis. The ISO first presented its proposed changes to Market Rule 1 to NEPOOL on October 13, 2005. Within six days thereafter, on October 19, 2005, the appropriate NEPOOL Technical Committees considered the Market Rule changes and made recommendations to the Participants Committee. Just two days later, the Participants Committee voted to support each of the elements of the Winter Package. A summary of the actions taken by the Participants Committee on the elements of the Winter Package and a tabulation of the corresponding votes are included as Attachment 5 hereto.

## **I. STANDARD OF REVIEW**

The ISO submits these changes to its filed rate pursuant to Section 205 of the FPA, which “gives a utility the right to file rates and terms for services rendered with its assets.”<sup>8</sup> Under Section 205, the Commission “plays ‘an essentially passive and reactive’ role”<sup>9</sup> whereby it “can reject [a filing] only if it finds that the changes proposed by the

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<sup>6</sup> As discussed in Section IV.F below, new Appendix I sets forth the Market Rule text that will be restored effective April 1, 2006.

<sup>7</sup> Revisions to Appendix H (“Operations During Cold Weather Conditions”) were filed with the Commission on September 8, 2005 as part of a Partial Settlement Agreement in Docket No. ER05-508-000. The settlement has been certified by the Honorable Herbert Grossman and is awaiting Commission action.

<sup>8</sup> *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

<sup>9</sup> *Id.* at 10 (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

public utility are not ‘just and reasonable.’”<sup>10</sup> The Commission limits this inquiry “into whether the rates proposed by a utility are reasonable -- and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs.”<sup>11</sup> The changes proposed herein “need not be the only reasonable methodology, or even the most accurate.”<sup>12</sup> As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept the ISO’s Section 205 filing if it finds it is just and reasonable.<sup>13</sup>

## II. STATEMENT OF ISSUES

The issue presented by this filing is whether the Market Rule 1 changes included in the Winter Package are just and reasonable. The purpose of these rule changes is to increase the likelihood that sufficient energy and capacity will be available to the ISO to maintain reliable operations during potential fuel shortage circumstances if they occur this coming winter.

## III. BACKGROUND: WINTER 2005/2006 ASSESSMENT AND ACTION PLAN

As noted in the Commission’s October 12, 2005 Staff Report, “Gulf Coast Storms Exacerbate Tight Natural Gas Supplies; Already High Prices Driven Higher” (the “Staff Report”), Hurricanes Katrina and Rita resulted in a significant loss of natural gas production that may subject New England to substantial uncertainty regarding the price, availability and deliverability of natural gas during the Winter 2005/2006 period. Specifically, on page 9 of the Staff Report, Commission Staff stated as follows:

Price increases are likely to be greater in the Northeast. A January/February forward contract for New England was about \$75 higher than one for PJM on September 30; on June 1 the difference was about \$24. This increased differential may reflect regional concerns about deliverability of natural gas through the winter. Scarcity premiums for natural gas also may cause winter price spikes in the Northeast, as they have in the last three years. Such spikes will be more likely (and perhaps higher) if gas

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<sup>10</sup> *Id.*

<sup>11</sup> *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

<sup>12</sup> *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

<sup>13</sup> *Cf. Southern California Edison Co., et al.*, 73 FERC ¶ 61,219 at 61,608 n. 73 (1995) (“Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters.” (citing *City of Bethany*, 727 F.2d at 1136)).

supply interruptions remain severe or if winter weather is colder than normal.

Electric power prices in the Northeast will be driven more by natural gas prices than by availability of electric generation. Lower winter loads reduce system demands, lower congestion costs and make the use of scarcity pricing unlikely. Still, electric price spikes resulting from gas price spikes are possible and could be aggravated by strains that extremely cold weather can put on the electric systems. The Northeast also faces a continuing need for infrastructure upgrades (for example, into southwest Connecticut), without which the transmission system is more vulnerable to strain.

As the ISO and NEPOOL explained in their January 28, 2005 filing of Appendix H to Market Rule 1,<sup>14</sup> the New England region has become increasingly reliant on natural gas-fired generation in recent years. In extreme cold weather conditions such as the cold snap of January 2004, the ability of generating Resources to make arrangements to obtain sufficient supplies of natural gas within acceptable bounds of risk and price may be severely limited.<sup>15</sup>

In order to evaluate the potential impact of Hurricanes Katrina and Rita upon New England's fuel supply for the coming winter, the ISO retained Levitan and Associates, Inc. to perform an independent assessment (the "Levitan Report") of the fuel supply conditions in the New England region for the coming winter.<sup>16</sup> The key findings of the Levitan Report were that:

- This winter, a significant amount of natural gas production may not be available to interstate pipelines serving the Atlantic seaboard. Consequently, natural gas and wholesale electricity prices will remain high throughout the heating season.
- New England has diverse natural gas supplies, including strong pipeline connections with Canada and imported liquefied natural gas. However, the region depends on two major interstate pipelines to bring in Gulf Coast

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<sup>14</sup> See the ISO and NEPOOL's January 28, 2005 transmittal letter in Docket No. ER05-508 at 3-6.

<sup>15</sup> See Final Report on Electricity Supply Conditions in New England During the January 14-16 2004 "Cold Snap," ISO New England Inc. Market Monitoring Department, October 12, 2004 (the "Cold Snap Report"), posted at [http://www.iso-ne.com/pubs/spcl\\_rpts/2004/cld\\_snp\\_rpt/1\\_Final\\_Report\\_On\\_January\\_2004\\_Cold\\_Snap.pdf](http://www.iso-ne.com/pubs/spcl_rpts/2004/cld_snp_rpt/1_Final_Report_On_January_2004_Cold_Snap.pdf)

<sup>16</sup> The Levitan Report, dated October 6, 2005, is attached hereto as Attachment 6 and posted at [http://www.iso-ne.com/pubs/spcl\\_rpts/2005/wnttr\\_assess/post\\_hurricane\\_outlook.pdf](http://www.iso-ne.com/pubs/spcl_rpts/2005/wnttr_assess/post_hurricane_outlook.pdf).

natural gas. To the extent that supply or delivery constraints arise, most of the region's natural gas-fired power plants could be adversely affected as a result of the "non-firm" character of their gas supply and transportation arrangements.

- The ISO can mitigate this winter's natural gas situation in part by increased use of oil-fired power plants. Supplies of fuel oil available to power plants and storage facilities accessible by barge or tanker ships are likely to be adequate for the winter. However, harsh winter weather could pose logistical challenges for truck-transported fuel oil shipments to some power plants, thereby affecting the reliability of fuel deliveries.
- Commercial demand reduction, such as demand response as well as residential energy efficiency and conservation initiatives, will play an integral part in ensuring the reliability of the region's bulk power system for the 2005-2006 heating season.

In response to the findings of the Levitan Report, and in order to address the possibility that severe cold weather conditions this winter may exacerbate fuel supply and pricing issues for New England generating Resources, the ISO developed a contingency plan for this winter (the "Winter 2005/2006 Action Plan"). The Winter 2005/2006 Action Plan includes the following objectives:

- Communicating the need to reduce consumption in all hours to conserve fuel;
- Encouraging the utilization of dual-fuel generating capability;
- Expanding demand-side management programs in New England in order to help maintain needed Operating Reserves; and
- Developing Emergency Energy procedures and Market Rules to complement the cold weather procedures set forth in Appendix H to Market Rule 1 to maintain reliability this winter during cold weather conditions.

The ISO presented its Winter 2005/2006 Action Plan on an expedited basis for consideration at the following stakeholder meetings this month: a stakeholder meeting on October 6, 2005, which included both Market Participants and representatives of state regulators; a special joint Markets/Reliability Committee meeting on October 13, 2005; and a Participants Committee meeting on October 14, 2005. Thereafter, the ISO described a new Operating Procedure and Market Rule 1 changes for consideration at a special joint Markets/Reliability Committee meeting on October 19, 2005 and a vote was taken on the Market Rule 1 changes at a special Participants Committee teleconference on October 21, 2005. In addition, the ISO's officers and staff have had or will have meetings with each of the New England states' governors and public utilities

commissions, state and federal legislators, the Commission, the Department of Energy, the Environmental Protection Agency, gas pipeline personnel and representatives of industry to explain the 2005/2006 Winter Action Plan and receive input on it.

As explained further in Section IV below, the Winter Package includes revisions to Market Rule 1 that will facilitate achievement of the 2005/2006 Winter Action Plan objectives and that can be implemented swiftly.<sup>17</sup> The use of a sunset date of March 31, 2006 will allow the ISO and the Market Participants to evaluate afresh whether and to what extent these or other measures should persist beyond this winter and, in particular, whether they are needed for upcoming winter seasons.

#### **IV. DESCRIPTION OF, AND JUSTIFICATION FOR, THE WINTER PACKAGE**

##### **A. Introduction and Overview**

The New England Markets are evolving. Some of the ongoing efforts to enhance the markets – such as Phase II of the Ancillary Service Markets (“ASM”) Project and a Locational Installed Capacity (“LICAP”) mechanism – will include features that would enhance the ability of the New England Market to address challenging weather and fuel supply situations. However, these features will not be in place for the winter of 2005/2006.<sup>18</sup> In the absence of market features to address the challenges from extreme cold weather or limited fuel supply, administrative elements of the Winter Package are necessary as a temporary measure to minimize reliability concerns. These elements are set specifically to expire at the end of this winter, on March 31, 2006.

The Winter Package includes revisions to Market Rule 1 that:

1. Increase flexibility of generating Resources to adjust Start-Up and No-Load offer parameters;
2. Eliminate the allocation of Real-Time Generation Obligation Deviation charges to Emergency Energy purchases from other Control Areas;

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<sup>17</sup> A number of other changes to Market Rule 1 were considered by the ISO and NEPOOL but were viewed as having limited benefit or as infeasible for quick implementation. In addition, as part of the 2005/2006 Winter Action Plan, the ISO is working with NEPOOL on the development of a new Operating Procedure No. 21 (“OP21”) to provide for periodic surveys of generator fuel availability and associated measures to anticipate and address Emergency Energy situations. As proposed, OP21 will complement existing ISO New England Operating Procedure No. 4, “Actions During a Capacity Deficiency.”

<sup>18</sup> Nor can the stakeholders and the ISO devise scarcity pricing or similar measures on short notice and in time for the upcoming winter.

3. Clarify the provisions of Market Rule 1 relating to “posturing” of generating Resources and modify the cost allocation;
4. Introduce a supplemental winter demand response program; and
5. Set forth the sunset mechanisms for the foregoing changes.

Each of these Market Rule changes is described below.

Clean versions of the tariff sheets reflecting these changes are included in this filing as Attachment 1, and redlined tariff sheets showing changes from the existing provisions on file with the Commission are included in this filing as Attachment 2.

#### **B. Increased Start-Up and No-Load Fee Flexibility**

The Winter Package includes two Market Rule 1 changes<sup>19</sup> relating to Start-Up and No-Load Fees.<sup>20</sup> The first is a revision to Section III.1.10.1A(d)(iii) of Market Rule 1 that will permit Market Participants to adjust Start-Up and No-Load Fees on a daily basis. The objective of this proposed change is to provide generating Resources additional flexibility to amend bidding characteristics in order to better reflect the costs of start-up and no-load operations, which are a function of fuel costs and spot energy purchases. Scarcity can lead to fuel price volatility, and a greater ability for generating Resources to track and recover fuel prices experienced in the markets through Start-Up and No-Load Fee adjustments will provide appropriate recognition of market realities.

By way of background, Section III.1 of Market Rule 1 requires that Supply Offers that are based on energy from a specific generating Resource that is internal to the New England Control Area must specify Start-Up and No-Load Fees equal to the amount of such fees that are on file with the ISO. Changes to Start-Up and No-Load Fees are only permitted during open periodic bidding enrollment periods. Currently, under Section III.1.10.1A(d)(iii) of Market Rule 1, such adjustments are only permitted to be made twice per month. Under the Market Rule change included here, such adjustments will be permitted daily to provide the opportunity to reflect current fuel pricing in those components of the Market Participant’s three-part Supply Offer.

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<sup>19</sup> As noted in Vote 1 on Attachment 5, the Participants Committee voted with 73.02 percent in favor to support the Market Rule changes addressing generator offer flexibility.

<sup>20</sup> Start-Up Fee is defined in Section III.1.3 of Market Rule 1 as “the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up....” No-Load Fee is defined in Section III.1.3 as “the amount, in dollars per hour, for a generating unit that must be paid to Market Participants with an Ownership Share in the unit for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the generating unit is scheduled in the New England Markets.”

The second Market Rule change is a revision to the market monitoring, reporting and market power mitigation provisions of Appendix A to Market Rule 1. Section III.A.5.3(a)(ii) of Appendix A currently provides that, for Resources in constrained areas, the ISO must assess the market impact of any Supply Offer-related increases that exceed certain thresholds, including Start-Up or No-Load Fees that represent an increase of 50 percent above the Reference Level applicable to the generating Resource in question. The Winter Package change to Appendix A lowers the aforementioned threshold percentage increase to 25 percent, in order to ensure adequate ISO oversight over daily generator adjustments to Start-Up and No-Load bids.

In short, since these adjustments will be permitted to be made daily rather than twice a month, it is essential that the ISO be able to assess significant changes in operating characteristics from day to day and the effects of such changes upon the New England Markets. Based upon an analysis of past market experience and consultations with the ISO's Independent Market Advisor, the ISO determined that lowering this threshold to 25 percent should adequately address this concern. Nevertheless, this adjustment will not override existing requirements for communication between the ISO's market monitoring unit and generating Resource owners regarding the basis for changes in Start-Up and No-Load Fees and other bid parameters.

### **C. Changes in Cost Allocations Relating to Emergency Energy Transactions**

The Winter Package includes two changes in cost allocations relating to import transactions entered into by Market Participants during Emergencies, in order to improve market signals with respect to such transactions.<sup>21</sup>

External Transaction purchases that represent Real-Time energy imports by Market Participants during Emergency conditions are often referred to in New England as "Emergency Energy Transactions" or "EETs."<sup>22</sup> A Market Participant scheduling an EET would have a Real-Time Generation Obligation Deviation equal to the EET megawatt-hour amount, because there is not a corresponding and offsetting Day-Ahead Generation Obligation.

Section III.3.2.6(a) of Market Rule 1 provides that hourly net costs in excess of Real-Time Prices attributable to the purchase of Emergency Energy by the ISO from other Control Areas must be allocated to Market Participants based on certain of their hourly deviations where such deviations are negative, including, among other items,

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<sup>21</sup> The Participants Committee voted with 74.53 percent in favor to support the Market Rule changes addressing the elimination of the allocation of Real-Time NCPC deviation charges to EETs. See Vote 2 on Attachment 5.

<sup>22</sup> Additional background concerning EETs is found in Section VII of ISO New England Operating Procedure No. 9.

“deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day.”

EETs are a valuable element of Emergency response that can help avoid Emergency Energy purchases by the ISO from other Control Areas, and to encourage these voluntary import transactions, the Winter Package modifies Section III.3.2.6(a) so that Market Participants engaging in EETs are not allocated a portion of hourly net costs above Real-Time Prices attributable to ISO Emergency Energy purchases on account of deviations stemming from those EET import transactions.

For the same reason, the Winter Package includes a corresponding modification to Section III.F.3.2.15(f) of Market Rule 1 (Appendix F), so that these EET-based deviations are not counted in the allocation of Operating Reserve Charges for the Real-Time Energy Market to Market Participants engaging in EET import transactions.

#### **D. Posturing-Related Changes**

The Winter Package includes several changes relating to the “posturing” of generating Resources, which in part are intended to provide a more appropriate allocation of the costs of posturing such Resources.

By way of background, Section III.1.11 of Market Rule 1 sets forth the procedures and principles that govern the dispatch of Resources in the New England Control Area. Section III.1.11.1 provides that the “ISO shall have the authority to adjust the output of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant’s Offer Data and Supply Offer.” Further, pursuant to Section III.1.11.1, the ISO is required to adjust the output of Pool-Scheduled increments as necessary to maintain reliability in New England. In addition, Section III.1.11.3(b) authorizes the ISO to “implement the dispatch of energy from other Pool-Scheduled Resource increments, including generation increments from ICAP Resources the remaining increments of which are Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources.” Finally, Section III.1.11.3(d) provides that “Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to desired output levels as practical, consistent with Accepted Electric Industry Practice.”

In accordance with these principles, the ISO has the authority to constrain down in the Energy Market or hold-off-line (“posture”) Pool-Scheduled Resources in order to maintain Operating Reserves during or in anticipation of shortage situations. The ISO recognizes that posturing units may depress prices. This practice is only used in order to ensure reliable operations in instances where shortages are forecasted. It is the ISO’s hope that the implementation of new market enhancements such as ASM and LICAP will reduce the need for posturing in the future.

Compensation for postured Resources is addressed in Section III.F.2.6 of Appendix F to Market Rule 1. Section III.F.2.6 provides in pertinent part that

“[w]henver the ISO deviates from the normal security constrained economic Energy dispatch solution for a generating Resource produced by the Technical Software for the purpose of maintaining sufficient Operating Reserve (both on-line and off-line) levels or for the provision of voltage or VAR support, such generating Resources shall be considered postured.” Generating Resources that are postured for the purpose of maintaining sufficient Operating Reserve receive Real-Time Operating Reserve Credit based on Posturing Credits calculated in accordance with Section III.F.2.6.2. No change to the foregoing posturing compensation is sought in the Winter Package.

Because the ISO may need to increase its use of posturing of generating Resources in order to manage day-to-day energy availability (due to fuel constraints) and maintain reliability this winter, the ISO engaged in a review of possible improvements to the Market Rules relating to posturing of generating Resources. Based on this ISO analysis, the Winter Package makes a clarifying revision to Section III.F.2.6.2 and conforms this section with the defined terms set forth in Market Rule 1. Specifically, Sections III.F.2.6.2(a) and (b) have been amended to clarify that generating resources with energy restrictions are Limited Energy Resources in order to conform this Section with the definition of Limited Energy Resources and to eliminate a redundancy.<sup>23</sup>

In addition, the Winter Package changes the allocation of costs of posturing of generating Resources in order to ensure that such costs are allocated in a manner that is consistent with the Commission’s cost causation principles. Section III.F.3.1 of Market Rule 1 (Appendix F) specifies the allocation of charges for Operating Reserve. In pertinent part, Section III.F.3.1 currently provides that Real-Time Operating Reserve Credits (including posturing credits) are allocated and charged to a Market Participant in proportion to its: (i) daily sum of Real-Time Load Obligation Deviations (excluding any difference between Dispatchable Load Demand Bids that are cleared in the Day-Ahead Energy Market and revenue quality meter readings for Dispatchable Load pumps for the Operating Day that result from operation in accordance with the ISO’s instructions), (ii) generation deviations from Day-Ahead amounts and (iii) daily sum of the generation deviations from the greater of the hourly aggregate Desired Dispatch Point or the Resource’s Economic Minimum Limit. In order to provide an appropriate allocation of the costs of posturing of generating Resources in order to maintain Operating Reserves,

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<sup>23</sup> Limited Energy Resource is defined as a Resource that “due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.”

These clarifying changes to Section III.F.2.6.2 of Appendix F were approved without opposition by the NEPOOL Participants Committee, provided that the resolution approving these changes included the following understanding: “it being understood that Resources who are postured as a result of this Rule change are not to be economically harmed because of that posturing and the ISO and the Markets Committee are to recommend as appropriate additional changes that may be necessary to reflect this conceptual agreement for effectiveness coincident with the change in the posturing rules.” *See* Vote 4 on the tabulation of votes included with Attachment 5.

the Winter Package amends this provision to provide as follows: “Real-Time Operating Reserve Credits associated with the posturing of facilities are allocated and charged to Market Participants in proportion to the daily sum of their Real-Time Load Obligations, excluding Real-Time Load Obligation associated with postured Dispatchable Load pump operation that is not Self-Scheduled or in merit.”<sup>24</sup>

This change was advocated by the ISO because of its belief that the allocation of costs for posturing of generating Resources in the manner provided in the existing Market Rule text is inconsistent with cost causation principles and Commission precedent. Real-Time load is the primary driver for the decision to posture generating Resources. Consequently, the ISO submits that it is appropriate that the costs of posturing generating Resources be allocated to those Market Participants that directly impact the amount of generation that is required to satisfy system reliability requirements. Thus, the ISO believes that all entities that have a Real-Time Load Obligation benefit from posturing, and therefore, cost-causation principles support allocation of posturing charges to such entities.

Furthermore, the ISO also believes that this amendment is consistent with the Commission’s recent approval of the ISO’s proposed allocation of Real-Time RMR Charges to Real-Time Load Obligation.<sup>25</sup> Specifically, in the June Order the Commission found as follows:

We also reject the argument that the ISO’s revised allocation methodology is inconsistent with cost causation principles. Because it is the forecast of Real-Time load and the need to reliably serve this load that requires ISO-NE to commit and dispatch an RMR resource, it is appropriate that ISO-NE’s Real-Time RMR Charges be allocated on the basis of load. Specifically, it is the existence of this Real Time load that primarily creates the need to dispatch an RMR resource.<sup>26</sup>

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<sup>24</sup> The Participants Committee voted with 82.27 percent in favor to support those revisions to the posturing rules of Market Rule 1 that addressed cost allocation. See Vote 7 on Attachment 5.

The load associated with the operation of pumped storage pumps (*i.e.*, Dispatchable Load pumps) is included in the calculation of a Market Participant’s Real-Time Load Obligation. Should a Dispatchable load pump be postured, the incremental pumping load is added, under current rules, to Real-Time Load Obligation. The proposed exclusion of the load associated with the operation of postured Dispatchable Load pumps will prevent pumped storage facilities that respond to ISO posturing instructions from being allocated a portion of the total posturing costs.

<sup>25</sup> See *ISO New England Inc.*, 110 FERC ¶ 61,250 (2005), *order on reh’g*, 111 FERC ¶ 61,442 (2005) (the “June Order”), *petition for review pending sub nom. Massachusetts Municipal Wholesale Electric Company v. FERC*, Docket No. 05-1329 (D.C. Circuit, filed August 18, 2005).

<sup>26</sup> June Order at P 19.

Similarly, the ISO's posturing of generating Resources to maintain system Operating Reserves is a reliability action that is based on forecasted load. All load benefits from such actions to maintain reliability. Accordingly, this Market Rule change is consistent with the Commission's ratemaking principle that those who cause a cost to be incurred should pay for such cost.<sup>27</sup>

While certain Market Participants may advocate that these costs should be allocated to Network Load (*i.e.*, to transmission owners and ultimately their transmission customers) rather than Real-Time Load Obligation (*i.e.*, to load),<sup>28</sup> the ISO submits that this would not be an appropriate allocation because it would unfairly assess these charges on transmission customers rather on load, which is the primary beneficiary of this reliability service. Posturing is a practice that is used to manage available generation and thus, is a reliability measure, not a transmission measure. The ISO's decision to posture generating Resources is based on the need to commit generation in Real-Time to satisfy load. Therefore, consistent with the Commission's principles of cost causation referred to above, the ISO urges the Commission to reject arguments that these costs should be allocated to Network Load.

Participants Committee support of this element of the Winter Package was premised in part on the following two additional modifications to the cost allocation and compensation methodologies relating to the posturing of generating Resources: (1) a provision that would prevent a generating Resource that is postured as a result of the proposed rule changes from being economically harmed as a result of that posturing and (2) a provision that would exclude non-recallable external transaction sales that are supported by self-scheduled energy from the unit providing capacity for non-recallable transaction from the posturing cost allocation calculation described above.<sup>29</sup> The ISO

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<sup>27</sup> See also, *Mansfield Municipal Electric Department and North Attleborough Electric Department v. New England Power Co.*, 97 FERC ¶ 61,134 at p. 61,615 (2001), *reh'g denied*, 98 FERC ¶ 61,115 (2002) (in addressing directly assigned versus rolled in rates, the Commission found that "it is a fundamental basis of Commission ratemaking that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the cost to be incurred"); *City of College Station, Texas*, 97 FERC ¶ 61,152 at p. 61,667 (2001), *reh'g denied*, 98 FERC ¶ 61,222 (2002), *reh'g denied*, 99 FERC ¶ 61,163 (2002) (Commission's finding regarding transmission services "is in keeping with the principle of cost causation, which provides that, insofar as possible, a company should recover its costs from the entities that cause the company to incur those costs. To the extent that a company follows this principle, it properly distributes its costs among those who take the services that give rise to the costs").

<sup>28</sup> A motion to amend the posturing rules so that Real-Time Operating Reserve Credits associated with the posturing of Resources would be allocated in accordance with Network Load failed with only approximately 46.92 percent of the NEPOOL Participants Committee in support.

<sup>29</sup> The Participants Committee on October 21, 2005 voted unanimously with 6 abstentions to add the following understanding to its vote on the posturing rules:

it being understood that Resources who are postured as a result of this Rule change are not to be economically harmed because of that posturing and the ISO and the Markets Committee are to recommend as appropriate additional changes that may be necessary to

(continued...)

expressed its preliminary support for these changes conceptually, subject to further detailed evaluation, and has committed to recommend to the Markets Committee, as appropriate, additional changes that would be necessary to reflect the requested conceptual changes and the ability to implement those changes coincident with the change in the posturing rules this winter.

#### **E. Demand Response Winter Supplemental Program**

The ISO recognizes the need to encourage the increased participation of demand response in the New England Markets. It is anticipated that the implementation of ASM Phase II will provide additional capability for Demand Resources to participate directly in the New England Markets. However, since these market enhancements have not yet been implemented, in order to increase the availability of additional Demand Resources to respond in the event of an energy shortage condition this winter, the Winter Package includes a supplemental Demand Response program (the “Winter Supplemental Program”).<sup>30</sup> Under the proposed Winter Supplemental Program, participants that reduce or transfer load or provide incremental generation<sup>31</sup> will be eligible to receive an incentive payment. In order to participate in the Winter Supplemental Program, a Demand Resource must:

- enroll in the 30-Minute Real-Time Demand Response Program and be available to participate on or before January 16, 2005;

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(...continued)

reflect this conceptual agreement for effectiveness coincident with the change in the posturing rules.

In addition, the Participants Committee on October 21, 2005 voted 63.13 percent in favor of adding the following understanding to its vote on the posturing rules:

it being understood that Real-Time Operating Reserve Credits associated with the posturing of facilities will not be allocated and charged to non-recallable exports and the ISO and the Markets Committee are to recommend as appropriate additional changes that may be necessary to reflect this conceptual agreement for effectiveness coincident with the change in the posturing rules.

<sup>30</sup> The Participants Committee voted with 62.19% in favor to support the addition of the Winter Supplemental Program. See Vote 10 on Attachment 5. Pursuant to Section 11.1.3 of the Participants Agreement, a NEPOOL Vote of at least 60% is required to register Participants Committee support for a proposed Market Rule change.

<sup>31</sup> As used in this filing letter, the term “Demand Resources” includes generating units owned by participants in the Winter Supplemental Program that are capable of supplying incremental energy in emergency conditions. Such units would be providing a valuable reliability service that is the equivalent of a reduction in load.

- be available for activation from 7:00 a.m. through 8:00 p.m. on all non-holidays and weekends from the date on which it is ready to respond through March 31, 2006; and
- agree to reduce its electricity consumption from the electricity grid (by reducing consumption, operating a generator, or both) during all Winter Supplemental Program events by an amount registered for such Demand Resource with the ISO's Customer Asset Management System by an Enrolling Participant ("Maximum Interruptible Capacity").

The rules governing the 30-Minute Real-Time Demand Response Program will also apply to the Winter Supplemental Program. However, Winter Supplemental Program events may extend through 8:00 p.m. on non-holiday weekdays.<sup>32</sup> In addition, the Winter Supplemental Program is limited to 450 MW.

Further, because the Winter Supplemental Program is designed to encourage Demand Resources that are not yet registered with the ISO to provide a reduction in energy consumption in accordance with the terms of the ISO's Real-Time 30-Minute Demand Response Program, those Generator Assets registered as of October 1, 2005, and Demand Resources receiving supplemental payments from the ISO for the period December 1, 2005 through March 31, 2006 pursuant to Agreements for Supplemental Installed Capacity for Southwest Connecticut, will not be eligible to participate in the Winter Supplemental Program.

Certain Market Participants have suggested that all existing generating units should be permitted to participate in the Winter Supplemental Program to the extent that such units are not already committed to provide UCAP. This argument is based on a misunderstanding of the intent of the Winter Supplemental Program. The ISO is seeking, in addition to interruptible load, additional incremental generation to increase the amount of Demand Resources available this winter. These incremental units have different cost concerns than generating Resources that are already Market Participants in the New England Markets. For example, such units must recover costs incurred for being able to enter into service for a limited time and with a limited lead time. Moreover, permitting registered generating Assets to participate in the Winter Supplemental Program would require further consideration, negotiation and (possibly) software development that the ISO does not believe can be accomplished in time to permit such Resources to participate in the Winter Supplemental Program. Therefore, the ISO urges the Commission to reject arguments that all existing generating units be permitted to participate in the Winter Supplemental Program for the reasons explained above.

In addition to payments made pursuant to the 30-Minute Real-Time Demand Response Program, participants in the Winter Supplemental Program will receive a

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<sup>32</sup> The 30-Minute Real-Time Demand Response Program is only applicable until 6:00 p.m.

payment for each month of the program (December 2005 through March 2006), calculated as follows: First, the ISO will determine the Demand Resource's average hourly interruption for the month by dividing that Demand Resource's total MWh reduction in the month by the number of Winter Supplemental Program event hours in the month; provided, however, that the average hourly interruption will be limited to 130 percent of the Demand Resource's Maximum Interruptible Capacity. Second, the Demand Resource's average hourly interruption for the month will be multiplied by the pertinent monthly incentive payment, as described in the next paragraph.

The monthly incentive payments for participants in the Winter Supplemental Program will be as follows:

December 2005: \$14/kW-month

January 2006: \$12/kW-month

February 2006: \$10/kW-month

March 2006: \$8/kW-month

The amounts of these payments was derived from the average of the accepted bids from the Southwest Connecticut Supplement Capacity Agreement solicitation for Winter 2005/2006.

To obtain these payments, a participant in the Winter Supplemental Program must achieve an interruption of at least 70 percent of its Maximum Interruptible Capacity in every 5-minute interval during the Winter Supplemental Program events hours in a month. If a participating Demand Resource fails to meet this threshold in any month, the Demand Resource's payment associated with the Winter Supplemental Program for that month will be zero.

If no Winter Supplemental Program events are called during a calendar month, each participating Demand Resource's payment associated with the Winter Supplemental Program for that month will be calculated using an average hourly interruption equal to the Demand Resource's average hourly interruption from a previous month in which the Demand Resource was a participant in the Winter Supplemental Program. If there were no Winter Supplemental Program events in a previous month, then the Demand Resource's average hourly interruption will be calculated using an average hourly interruption equal to the Demand Resource's Maximum Interruptible Capacity as registered in the ISO's Customer Asset Management System; provided, however, that the ISO may perform an audit to establish average hourly interruption and maximum interruption amounts for the month.

To the extent that a Demand Resource enrolled in the Demand Response Winter Supplemental Program becomes ready to respond to Demand Response Winter Supplemental Program events after the beginning of a calendar month, payments associated with the Demand Response Winter Supplemental Program for that month shall be prorated by the ratio of non-holiday weekdays in the month on which the Demand Resource was ready to respond to the total number of non-holiday weekdays in the month.

All monthly payments associated with the Demand Response Winter Supplemental Program will be issued to Enrolling Participants after March 31, 2006.

The ISO acknowledges that the Winter Supplemental Program is not its preferred solution to address power supply issues stemming from potential fuel scarcity. The ISO's strong preference for effectively addressing these types of situations is through implementation of both effective locational capacity markets (such as the LICAP proposal) and the projects contained within ASM Phase II. Once these markets are in place, and only if it is effectively shown that they cannot properly protect reliability, the ISO would issue an asset-neutral Gap RFP for Reliability Purposes in accordance with Section III.10 of Market Rule 1. However, there is insufficient time to accomplish these objectives in advance of the coming winter season.<sup>33</sup>

Consequently, the ISO and NEPOOL propose to implement the Winter Supplemental Program as an interim solution through which it hopes to attract additional Demand Resources this coming winter.

#### **F. Sunset for the Winter Package**

As noted above, the ISO and NEPOOL propose that all of the Market Rule revisions in the Winter Package will expire after March 31, 2006. On or around April 1, 2006, the ISO has committed to file with the Commission tariff sheets that will undo the changes to Market Rule 1 associated with the Winter Package. In connection with this commitment, the Winter Package includes a new Appendix I to Market Rule 1 that sets forth the provisions that the ISO will cause to revert to their previous form, and shows the nature of the reversion.

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<sup>33</sup> The Commission has deferred the implementation of LICAP, until no earlier than October 1, 2006. See *Devon Power LLC*, 112 FERC ¶ 61,179 (2005). The Participants Committee has recently given conceptual support to ASM Phase II, and implementing rules must be prepared, reviewed and filed with the Commission before ASM Phase II changes can be made effective.

With respect to Gap RFPs, Section III.10.1(a) requires that the ISO must file any such Gap RFP with the Commission for approval at least 60 days prior to its issuance. Moreover, and more importantly, following the issuance of a Gap RFP, the ISO would need to (i) evaluate bids and (ii) negotiate and enter into contracts with winning bidders, which contracts would then need to be filed with the Commission for approval. Even with a waiver of the sixty-day period, the cumulative process is, in the ISO's experience, time-consuming and could not possibly be completed in time to have any reliability benefit for this winter.

## **V. REQUESTS FOR SHORTENED COMMENT PERIOD, EXPEDITED CONSIDERATION AND WAIVER**

The ISO and NEPOOL request a shortened, 14-day comment period and expedited consideration and acceptance of the Winter Package with an effective date of December 1, 2005 in order to address fuel supply issues during the rapidly approaching winter season.<sup>34</sup> While the occasions on which these measures are necessary may be infrequent, the need could occur at any time this winter. Further, to the extent protests challenge the cost allocation of Real-Time Operating Reserve Credits related to the posturing of generating Resources in order to maintain Operating Reserves, the ISO urges the Commission not to delay approval of the critical interim measures included in the Winter Package due to a cost allocation issue that has already been addressed by the Commission in a similar context.<sup>35</sup>

In addition, good cause exists for waiver of the Commission's 60-day notice requirement. The pressing need for the Winter Package has been explained above. Several special meetings of the Markets, Reliability and Participants Committees have been held to consider an appropriate response to the aftermath of Hurricanes Katrina and Rita. The ISO has worked and continues to work closely with NEPOOL in the development of the Winter Package and other related elements of the Winter 2005/2006 Action Plan. Market Participants are well aware of the nature of the Energy shortage concerns of the ISO, and of the elements of the Winter Package, and have had the opportunity to provide input on the Winter Package.

In furtherance of this request for expedited consideration, the ISO respectfully requests that the Commission require that the deadline for submitting protests and comments with regard to this filing be no longer than 14 days from the date hereof. In addition, the ISO requests that the Commission direct that any responses to comments and protests be submitted within 5 days.

## **VI. ADDITIONAL SUPPORTING INFORMATION**

The following information is provided pursuant to Section 35.13 et seq. of the Code of Federal Regulations:

35.13(b)(1) - Materials included herewith are as follows:

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<sup>34</sup> In his opening statement at the Commission's October 12, 2005 conference, "Commission Plans to Address Potentially Tight Winter Energy Supplies of Natural Gas," Chairman Kelliher noted that the Commission "stands ready to act quickly on emergency filings to authorize efficient use of existing gas infrastructure."

<sup>35</sup> To the extent that the Commission were to accept this change to the allocation formula as effective on December 1, 2005, but subject to refund, and then subsequently require a different allocation methodology, the ISO would be able to retroactively correct this calculation and credit Market Participants accordingly.

- This transmittal letter;
- revised tariff sheets of Market Rule 1 reflecting the changes proposed by this filing (Attachment 1);
- revised tariff sheets of Market Rule 1 marked to show changes to the currently effective sheets proposed by this filing (Attachment 2);<sup>36</sup>
- a list of Participants Committee members and alternates to whom a copy of this filing has been sent electronically, along with a list of non-Participant Transmission Customers to which a paper copy of this filing has been sent (Attachment 3);
- a list of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent (Attachment 4);
- a summary of the actions taken by the Participants Committee and a tabulation of those votes (Attachment 5); and
- the Levitan Report (Attachment 6).

35.13(b)(2) - The ISO and NEPOOL request waiver of the 60-day notice requirement of 18 C.F.R. § 35.3(a) (2005) and that the Commission accept the Winter Package effective as of December 1, 2005.

35.13(b)(3) - Attachment 3 to this transmittal letter includes the names and addresses of all Participants Committee members and alternates, who represent all of the electric utilities rendering or receiving service under the Second Restated NEPOOL Agreement, as well as each of the independent power producers, marketers, brokers, load aggregators, consumer-owned utility systems, demand response providers, merchant transmission providers, and end users that are currently NEPOOL Participants. All Participants Committee members and alternates have been furnished with an electronic copy of this filing, together with this transmittal letter and the accompanying materials. All non-Participant Transmission Customers, also listed in Attachment 3, have also been sent a paper copy of this filing. This transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states which comprise the New England Control Area, and to the New England Conference of Public Utility Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 4. In accordance with

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<sup>36</sup> Attachment 2 includes only those tariff sheets currently on file with the Commission that this filing proposes to change. The new tariff sheets this filing proposes to create (*i.e.*, the "Original" sheets included in Attachment 1) are not included with the blacklined sheets in Attachment 2.

Commission rules and practice, there is no need for the entities identified on Attachments 3 and 4 to be included on the Commission's official service list in the captioned proceedings unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the rate schedule changes is contained in this transmittal letter and the Attachments referenced herein.

35.13(b)(5) - A statement of the reasons for this filing is discussed in this transmittal letter.

35.13(b)(6) - The ISO's approval of these changes is evidenced by this filing. These changes reflect the results of the Participant Processes required by the Participants Agreement and have the support of the NEPOOL Participants Committee.

35.13(b)(7) - Neither the ISO nor NEPOOL has any knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(c)(1) - The changes, if any, in sales, services and revenues in the markets due to the proposed rule change cannot be reasonably forecasted and no comparison with earlier sales, services, and revenues is possible.

35.13(c)(2) - The ISO does not provide services under other rate schedules that are similar to the wholesale resale and transmission services it provides under the Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in order to implement the Winter Package.

Honorable Magalie R. Salas

October 28, 2005

Page 20 of 21

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Honorable Magalie R. Salas

October 28, 2005

Page 21 of 21

Please acknowledge receipt of the foregoing by date-stamping the enclosed extra copies of this filing and returning them to the courier delivering this filing.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Its Counsel

## **Attachment 1**

- (i) Shall specify the generating Resource and energy for each hour in the offer period;
- (ii) Shall specify the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO;
- (iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up and No-Load Fees equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (daily));
- (iv) Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment;
- (v) Shall specify a minimum run time to be used for scheduling purposes that does not exceed 24 hours;
- (vi) Shall constitute an offer to submit the Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the

Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generation Resources shall have a 5% or 5 MWh threshold when determining such deviations.

- (b) Hourly net revenues in excess of Real-Time Prices attributable to the sale of Emergency energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations

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been provided, shall be mitigated to the Reference Level determined as specified in Section III.A.5.6, unless an agreement has been negotiated under the procedures set forth in *Exhibit 2* to this *Appendix A*.

(a) For Supply Offers for the Real-Time Market: for intervals in which a generating Resource is dispatched for the purpose of relieving a transmission constraint above the level at which it otherwise would have been dispatched (“Constrained Hours”), the ISO shall assess the market impact of any Supply Offers (Section III.A.5.5.2(b)) that meet the following thresholds:

(i) Energy Offer Price – an increase of \$25 or 50%, whichever is lower, above the Reference Level; or

(ii) Start-Up or No-Load Price – an increase of 25% above the Reference Level.

(b) For Supply Offers for the Day-Ahead Market: for all Constrained Hours (as defined above) the ISO shall assess the market impact of any Supply Offers for the generating Resource that meet a threshold determined in accordance with the formula specified in subsection (a).

**III.A.5.4. Threshold for Identifying Uneconomic Production.** In addition to the thresholds governing forms of economic withholding in Section III.A.5.3.3, the ISO will monitor for actions not consistent with competitive conduct, as defined in Section III.A.2.2.2, involving uneconomic production. The following thresholds may warrant the imposition of a Mitigation

**APPENDIX E**  
**LOAD RESPONSE PROGRAM**

**Table of Contents**

III.E.1. Introduction.....	7902
III.E.2. Day-Ahead Load Response Program.....	7906
III.E.3. Real-Time Demand Response Programs .....	7908
III.E.4. Real-Time Price Response Program .....	7911
III.E.5. Real-Time Profiled Response Program .....	7913
III.E.6. Metering and Settlement .....	7915
III.E.7. Installation Cost of Internet-based Communication Systems .....	7916
III.E.9. Demand Response Winter Supplemental Program .....	7932

### **III.E.9 Demand Response Winter Supplemental Program**

**III.E.9.1 Generally.** The ISO will implement a Demand Response Winter Supplemental Program for the period December 1, 2005 through March 31, 2006. Demand Resources eligible to participate in the program must enroll in both the 30-Minute Real-Time Demand Response Program and the Demand Response Winter Supplemental Program, and must be ready to respond no later than January 16, 2006. Registration in the Demand Response Winter Supplemental Program shall be limited to 450 MW, with eligible Demand Resources accepted on a first-come, first-served basis. Except for the provisions of this Section III.E.9, the rules governing the 30-Minute Real-Time Demand Response Program shall also apply to the Demand Response Winter Supplemental Program.

**III.E.9.2 Eligibility.** To be eligible to participate in the Demand Response Winter Supplemental Program, a Demand Resource must: (i) be available for dispatch from 7 a.m. through 8 p.m. on non-holiday weekdays from the date it is ready to respond in the Demand Response Winter Supplemental Program through March 31, 2006; and (ii) agree to reduce its electricity consumption from the electricity grid (by reducing consumption, operating a generator, or both) during all Demand Response Winter Supplemental Program events by an

amount approximating the amount of capacity registered for the Demand Resource in the ISO's Customer Asset Management System by an Enrolling Participant ("Maximum Interruptible Capacity"). Demand Response Winter Supplemental Program events shall include all ISO instructions pursuant to the 30-Minute Real-Time Demand Response Program; provided, however, that such events could extend through 8 p.m. on non-holiday weekdays.

Generator Assets registered as of October 1, 2005, and Demand Resources receiving supplemental payments for the period December 1, 2005 through March 31, 2006 from the ISO pursuant to Agreements for Supplemental Installed Capacity for Southwest Connecticut are not eligible to participate in the Demand Response Winter Supplemental Program.

**III.E.9.3 Payments.** In addition to payments made pursuant to the 30-Minute Real-Time Demand Response Program, participants in the Demand Response Winter Supplemental Program will receive a payment for each month of the program (December 2005 through March 2006), calculated as follows: First, the ISO will determine the Demand Resource's average hourly interruption for the month by dividing that Demand Resource's total MWh reduction in the month by the number of Demand Response Winter Supplemental Program event hours in the month; provided, however, that the average hourly interruption shall be limited to 130 percent of

the Demand Resource's Maximum Interruptible Capacity. Second, the Demand Resource's average hourly interruption for the month will be multiplied by the supplemental price for the month. The monthly supplemental price schedule is as follows:

December 2005:	\$14/kW – month
January 2006:	\$12/kW – month
February 2006:	\$10/kW – month
March 2006:	\$8/kW – month

If in every 5-minute interval during Demand Response Winter Supplemental Program event hours in a month, a Demand Resource fails to achieve an interruption of at least 70 percent of its Maximum Interruptible Capacity, then the Demand Response Winter Supplemental Program payment for that Demand Resource for the month would be zero.

If no Demand Response Winter Supplemental Program events are called during a calendar month, each Demand Resource's payment associated with the Demand Response Winter Supplemental Program for that month will be calculated using an average hourly interruption equal to the Demand Resource's average hourly interruption from a previous month. If there were no Demand Response Winter Supplemental Program events in a previous month,

then the Demand Resource's average hourly interruption will be calculated using an average hourly interruption equal to the Demand Resource's Maximum Interruptible Capacity as registered in the ISO's Customer Asset Management System; provided, however, that the ISO may perform an audit to establish average hourly interruption and maximum interruption amounts for the month.

To the extent that a Demand Resource enrolled in the Demand Response Winter Supplemental Program becomes ready to respond to Demand Response Winter Supplemental Program events after the beginning of a calendar month, payments associated with the Demand Response Winter Supplemental Program for that month shall be prorated by the ratio of non-holiday weekdays in the month on which the Demand Resource was ready to respond to the total number of non-holiday weekdays in the month.

All monthly payments associated with the Demand Response Winter Supplemental Program will be issued to Enrolling Participants after March 31, 2006.

Sheet Nos. 7936 through 7999 are reserved for future use.

**III.F.2.6.1 Information Retrieved.** The ISO retrieves the following information:

- (a) list of generating Resources reduced or suspended for reliability reasons (dispatcher log)
- (b) Generator Offer Data
- (c) 5 minute generation data from EMS
- (d) Real-Time LMP data
- (e) Real-Time Generation Obligation
- (f) Generator Regulation Credits

**III.F.2.6.2 Posturing Credit Calculation.** The ISO Credits Market Participants for each generating Resource for each hour reduced or suspended based on the following calculation:

(a) *Generating Resources Without Energy Restrictions.* For generating Resources without energy restrictions (generating Resources that are not Limited Energy Resources), the posturing credit for each hour of reduced or suspended operation is:

$$\text{Posturing Credit} = (\text{PAG} - \text{AG}) \times (\text{ULMP} - \text{UB}) - \text{GRC}$$

Where:

- PAG equals the estimated hourly generation had the generating Resource not responded to dispatch orders to reduce or suspend operation. Estimated operation for resources following the Day-Ahead schedule prior to posturing will be determined by the Day-Ahead schedules during the posturing event. For generating Resources responding to Real-Time prices prior to posturing, estimates will assume economic operation would have continued;
- AG equals the actual output of the generating Resource;
- ULMP equals the Real-Time LMP associated with the generating Resource that is reduced or suspended for each hour;
- UB equals the Supply Offer price (increment energy price only) associated with PAG for that generating Resource whose output is reduced or suspended;
- GRC (Generator Regulation Credits) is the value calculated under Section 4.2.1 of the ISO New England Manual for Market Rule 1 Accounting, M-28; and

where  $ULMP - UB$  shall not be negative and Posturing Credit shall not be negative.

(b) *Generating Resources With Energy Restrictions.* For generating Resources with energy restrictions (generating Resources that are Limited Energy Resources), a credit is determined based on an estimate of the daily net opportunity cost in the energy market. This daily net amount shall not be negative. The posturing credit is:

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Credits including those associated with Synchronous Condensers for the Real-Time Energy Market is allocated and charged to Market Participants in proportion to their daily sum of their Real-Time Load Obligation Deviations (excluding any difference between Dispatchable Load Demand Bids that are cleared in the Day-Ahead Energy Market and revenue quality meter readings for Dispatchable Load pumps for the Operating Day that result from operation in accordance with the ISO's instructions), generation deviations from Day-Ahead amounts and the daily sum of the generation deviations from the greater of the hourly aggregate Desired Dispatch Point or the Resource's Economic Minimum Limit. Real-Time Operating Reserve Credits associated with the posturing of facilities are allocated and charged to Market Participants in proportion to the daily sum of their Real-Time Load Obligations, excluding Real-Time Load Obligation associated with postured Dispatchable Load pump operation that is not Self-Scheduled or in-merit.

The sum of Day-Ahead RMR Operating Reserve Credits associated with generating units identified as Daily RMR Resources for the Day-Ahead Energy Market is allocated and charged

[NOTE: External Transaction sales curtailed by the ISO are omitted from this calculation],

**plus,**

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation

[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation],

**plus,**

(g) the absolute value of the total over all Locations of the Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Market always creates a Real-Time generation deviation.]

**SECTION III**

**MARKET RULE 1**

**APPENDIX I**

**WINTER 2005/2005 SUNSET PROVISIONS**

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### **III.I.1 Winter 2005/2006 Sunset Provisions**

The following provisions of Market Rule 1 and its Appendices will be revised as follows, effective April 1, 2006. These revisions are intended to reverse the changes to Market Rule 1 and its Appendices filed with the Commission on October 28, 2005. On or around April 1, 2006, the ISO will file with the Commission Market Rule 1 tariff sheets reflecting these changes. This reversion is intended to affect only the specific changes filed on October 28, 2005, and other changes to the same sections pending or accepted in the interim will be unaffected.

#### **III.I.1.1 Start-Up and No-Load Flexibility**

##### Section III.1.10.1A(d)(iii)

“If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up and No-Load Fees equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (twice a monthdaily));”

##### Section III.A.5.3.3(a)(ii)

“Start-Up or No-Load Price – an increase of 2550% above the Reference Level.”

#### **III.I.1.2 Allocation of Real-Time NCPC Deviation Charges to Emergency Energy Transactions**

##### Section III.3.2.6(a)

“Hourly net costs in excess of Real-Time Prices attributable to the purchase of Emergency energy by the ISO from other Control Areas shall be allocated to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions,

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including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day ~~except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation.~~ As provided for in the ISO New England Manuals, generation Resources shall have a 5% or 5 MWh threshold when determining such deviations.”

Section III.F.3.2.15(f)

“the sum of the hourly absolute values for the Operating Day of the Participant’s Real-Time Generation Obligation Deviation at External Nodes ~~except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation~~

[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation], **plus”**

**III.I.1.3 Posturing Changes**

Section III.F.2.6.2(a)

“*Generating Resources Without Daily Energy Restrictions.* For generating Resources without daily energy restrictions ~~(generating Resources that are not Limited Energy Resources)~~, the posturing credit for each hour of reduced or suspended operation is:”

[remainder of subsection unchanged]

Section III.F.2.6.2(b)

“*Generating Resources With Daily Energy Restrictions.* For generating Resources with daily energy restrictions ~~(generating Resources that are Limited Energy Resources)~~, a credit is determined based on an estimate of the daily net opportunity cost in the energy market. This daily net amount shall not be negative. The posturing credit is:”

[remainder of subsection unchanged]

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### Section III.F.3.1

“The sum of Day-Ahead Operating Reserve Credits for the Day-Ahead Energy Market is allocated and charged to Market Participants in proportion to the daily sum of their Day-Ahead Load Obligations. The sum of Real-Time Operating Reserve Credits (including posturing Credits) including those associated with Synchronous Condensers for the Real-Time Energy Market is allocated and charged to Market Participants in proportion to their daily sum of their Real-Time Load Obligation Deviations (excluding any difference between Dispatchable Load Demand Bids that are cleared in the Day-Ahead Energy Market and revenue quality meter readings for Dispatchable Load pumps for the Operating Day that result from operation in accordance with the ISO’s instructions), generation deviations from Day-Ahead amounts and the daily sum of the generation deviations from the greater of the hourly aggregate Desired Dispatch Point or the Resource’s Economic Minimum Limit. ~~Real-Time Operating Reserve Credits associated with the posturing of facilities are allocated and charged to Market Participants in proportion to the daily sum of their Real-Time Load Obligations, excluding Real-Time Load Obligation associated with postured Dispatchable Load pump operation that is not Self-Scheduled or in-merit.~~”

[remainder of section unchanged]

#### **III.I.1.4 Demand Response Winter Supplemental Program**

Section III.E.9, instituting the Demand Response Winter Supplemental Program for the period December 1, 2005 through March 31, 2006, will be removed in its entirety.

#### **III.I.1.5 Winter 2005/2006 Sunset Provisions**

This Appendix I, specifying which provisions of Market Rule 1 and its Appendices will sunset on April 1, 2006, will be removed in its entirety.

Sheet Nos. 8229 through 8499 are reserved for future use.

## **Attachment 2**

- (i) Shall specify the generating Resource and energy for each hour in the offer period;
- (ii) Shall specify the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO;
- (iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up and No-Load Fees equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (daily twice a month));
- (iv) Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment;
- (v) Shall specify a minimum run time to be used for scheduling purposes that does not exceed 24 hours;
- (vi) Shall constitute an offer to submit the Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the

Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generation Resources shall have a 5% or 5 MWh threshold when determining such deviations.

- (b) Hourly net revenues in excess of Real-Time Prices attributable to the sale of Emergency energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations

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been provided, shall be mitigated to the Reference Level determined as specified in Section III.A.5.6, unless an agreement has been negotiated under the procedures set forth in *Exhibit 2* to this *Appendix A*.

(a) For Supply Offers for the Real-Time Market: for intervals in which a generating Resource is dispatched for the purpose of relieving a transmission constraint above the level at which it otherwise would have been dispatched (“Constrained Hours”), the ISO shall assess the market impact of any Supply Offers (Section III.A.5.5.2(b)) that meet the following thresholds:

(i) Energy Offer Price – an increase of \$25 or 50%, whichever is lower, above the Reference Level; or

(ii) Start-Up or No-Load Price – an increase of ~~50~~25% above the Reference Level.

(b) For Supply Offers for the Day-Ahead Market: for all Constrained Hours (as defined above) the ISO shall assess the market impact of any Supply Offers for the generating Resource that meet a threshold determined in accordance with the formula specified in subsection (a).

**III.A.5.4. Threshold for Identifying Uneconomic Production.** In addition to the thresholds governing forms of economic withholding in Section III.A.5.3.3, the ISO will monitor for actions not consistent with competitive conduct, as defined in Section III.A.2.2.2, involving uneconomic production. The following thresholds may warrant the imposition of a Mitigation

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**APPENDIX E**  
**LOAD RESPONSE PROGRAM**

**Table of Contents**

III.E.1. Introduction.....	7902
III.E.2. Day-Ahead Load Response Program.....	7906
III.E.3. Real-Time Demand Response Programs .....	7908
III.E.4. Real-Time Price Response Program .....	7911
III.E.5. Real-Time Profiled Response Program .....	7913
III.E.6. Metering and Settlement .....	7915
III.E.7. Installation Cost of Internet-based Communication Systems .....	7916
<u>III.E.9. Demand Response Winter Supplemental Program .....</u>	<u>7932</u>

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**III.F.2.6.1 Information Retrieved.** The ISO retrieves the following information:

- (a) list of generating Resources reduced or suspended for reliability reasons (dispatcher log)
- (b) Generator Offer Data
- (c) 5 minute generation data from EMS
- (d) Real-Time LMP data
- (e) Real-Time Generation Obligation
- (f) Generator Regulation Credits

**III.F.2.6.2 Posturing Credit Calculation.** The ISO Credits Market Participants for each generating Resource for each hour reduced or suspended based on the following calculation:

(a) *Generating Resources Without ~~Daily~~ Energy Restrictions.* For generating Resources without ~~daily~~ energy restrictions (generating Resources that are not Limited Energy Resources), the posturing credit for each hour of reduced or suspended operation is:

$$\text{Posturing Credit} = (\text{PAG} - \text{AG}) \times (\text{ULMP} - \text{UB}) - \text{GRC}$$

Where:

- PAG equals the estimated hourly generation had the generating Resource not responded to dispatch orders to reduce or suspend operation. Estimated operation for resources following the Day-Ahead schedule prior to posturing will be determined by the Day-Ahead schedules during the posturing event. For generating Resources responding to Real-Time prices prior to posturing, estimates will assume economic operation would have continued;
- AG equals the actual output of the generating Resource;
- ULMP equals the Real-Time LMP associated with the generating Resource that is reduced or suspended for each hour;
- UB equals the Supply Offer price (increment energy price only) associated with PAG for that generating Resource whose output is reduced or suspended;
- GRC (Generator Regulation Credits) is the value calculated under Section 4.2.1 of the ISO New England Manual for Market Rule 1 Accounting, M-28; and

where  $ULMP - UB$  shall not be negative and Posturing Credit shall not be negative.

(b) *Generating Resources With ~~Daily~~-Energy Restrictions.* For generating Resources with ~~daily~~-energy restrictions (generating Resources that are Limited Energy Resources), a credit is determined based on an estimate of the daily net opportunity cost in the energy market. This daily net amount shall not be negative. The posturing credit is:

---

Credits ~~(including posturing Credits)~~ including those associated with Synchronous Condensers for the Real-Time Energy Market is allocated and charged to Market Participants in proportion to their daily sum of their Real-Time Load Obligation Deviations (excluding any difference between Dispatchable Load Demand Bids that are cleared in the Day-Ahead Energy Market and revenue quality meter readings for Dispatchable Load pumps for the Operating Day that result from operation in accordance with the ISO's instructions), generation deviations from Day-Ahead amounts and the daily sum of the generation deviations from the greater of the hourly aggregate Desired Dispatch Point or the Resource's Economic Minimum Limit. Real-Time Operating Reserve Credits associated with the posturing of facilities are allocated and charged to Market Participants in proportion to the daily sum of their Real-Time Load Obligations, excluding Real-Time Load Obligation associated with postured Dispatchable Load pump operation that is not Self-Scheduled or in-merit.

The sum of Day-Ahead RMR Operating Reserve Credits associated with generating units identified as Daily RMR Resources for the Day-Ahead Energy Market is allocated and charged

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[NOTE: External Transaction sales curtailed by the ISO are omitted from this calculation],

**plus,**

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation

[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation],

**plus,**

(g) the absolute value of the total over all Locations of the Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Market always creates a Real-Time generation deviation.]

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**Vermont Electric Cooperative**  
182 School Street  
Johnson, VT 05656

Thomas N. Wies  
Vice President & General Counsel  
**Vermont Electric Power Company, Inc.**  
366 Pinnacle Ridge Road  
Rutland, VT 05701

Scott Mallory (Alt)  
**Vermont Electric Power Company, Inc.**  
366 Pinnacle Ridge Road  
Rutland, VT 05701

Todd Allard  
**Vermont Marble Company**  
61 Main Street  
Proctor, VT 05765

Michael Boyea (Alt)  
**Vermont Marble Company**  
61 Main Street  
Proctor, VT 05765

William J. Gallagher  
General Manager  
**Vermont Public Power Supply Authority**  
P.O. Box 298  
Waterbury Center, VT 05677

Brian Evans-Mongeon (Alt)  
Manager of Power Supply & Marketing Service  
**Vermont Public Power Supply Authority**  
P.O. Box 298  
Waterbury Center, VT 05677

William J. Wallace  
Manager  
**Wakefield Municipal Gas and Light Department**  
9 Albion Street  
P.O. Box 190  
Wakefield, MA 01880-0390

**NEPOOL Participants Committee**  
**Members and Alternates**

Tim Peet (Alt)  
**Wakefield Municipal Gas and Light  
Department**  
c/o Mass. Municipal Wholesale Electric Co.  
Moody Street  
P.O. Box 426  
Ludlow, MA 01056-0246

Mark Noyes  
**WebGen Systems Inc.**  
41 William Linsky Way  
Cambridge, MA 02142

Paul Taglianetti (Alt)  
**WebGen Systems Inc.**  
41 William Linsky Way  
Cambridge, MA 02142

Richard F. Joyce  
Director  
**Wellesley Municipal Lighting Plant**  
455 Worcester Street  
Wellesley, MA 02481

Joyce M. D. Wood (Alt)  
**Wellesley Municipal Lighting Plant**  
c/o Onway Lake Consulting  
11 Forest Road  
Raymond, NH 03077

John Scirpoli  
Manager  
**West Boylston Municipal Lighting Plant**  
4 Crescent Street  
West Boylston, MA 01583-1310

Tim Peet (Alt)  
**West Boylston Municipal Lighting Plant**  
c/o Mass. Municipal Wholesale Electric Co.  
Moody Street  
P.O. Box 426  
Ludlow, MA 01056-0246

Richard J. Munson  
Director of Plant Operations  
**The Westerly Hospital**  
25 Wells Street  
Westerly, RI 02891

**October 26, 2005**

August Fromuth (Alt)  
**The Westerly Hospital**  
c/o Freedom Energy Partners, LLC  
816 Elm Street  
Suite 364  
Manchester, NH 03101

Daniel Golubek (Alt)  
Manager  
**Westfield Gas and Electric Light Department**  
100 Elm Street  
Westfield, MA 01085-2907

Tim Peet (Alt)  
**Westfield Gas and Electric Light Department**  
c/o Mass. Municipal Wholesale Electric Co.  
Moody Street  
P.O. Box 426  
Ludlow, MA 01056-0246

David K. Singer  
**Williams Power Company, Inc.**  
One Williams Center  
Tulsa, OK 74172

Dennis Keener (Alt)  
**Williams Power Company, Inc.**  
One Williams Center  
Mail Drop 35-7  
P.O. Box 3448  
Tulsa, OK 74101-9567

Tim Charette  
Power Marketing Executive  
**WPS Energy Services Inc.**  
1242 Lower Lyndon Street  
Caribou, ME 04736

Ed Howard (Alt)  
Power Marketing Executive  
**WPS Energy Services Inc.**  
1242 Lower Lyndon Street  
Caribou, ME 04736

F. Paul Russo  
**ZTECH, LLC**  
8 Dow Road  
Bow, NH 03304

**NEPOOL Participants Committee**  
**Members and Alternates**

**October 26, 2005**

August Fromuth (Alt)  
**ZTECH, LLC**  
c/o Freedom Energy Partners, LLC  
816 Elm Street  
Suite 364  
Manchester, NH 03101

**Non-Market Participant Transmission Customers**

**October 26, 2005**

Miller Hydro Group  
P.O. Box 97  
Lisbon Falls, ME 04252-0097

Massachusetts Government Land Bank  
Devens Commerce Center  
43 Buena Vista  
Ft. Devens, MA 01433

Town of Wolfeboro Municipal Electric Department  
84 S. Main St.  
Wolfeboro, NH 03894

Princeton Municipal Light Department  
168 Worcester Road, PO Box 247  
Princeton, MA 01541

## **Attachment 4**

**New England Governors  
and Utility Regulatory  
and Related Agencies**

**October 26, 2005**

Connecticut

The Honorable M. Jodi Rell  
State Capitol  
210 Capitol Ave.  
Hartford, CT 06106

Connecticut Department of Public Utility  
Control  
10 Franklin Square  
New Britain, CT 06051-2605

Maine

The Honorable John E. Baldacci  
One State House Station  
Rm. 236  
Augusta, ME 04333-0001

Maine Public Utilities Commission  
State House, Station 18  
242 State Street  
Augusta, ME 04333-0018

Massachusetts

The Honorable Mitt Romney  
Office of the Governor  
Rm. 360 State House  
Boston, MA 02133

Massachusetts Department of Telecommunications  
and Energy  
One South Station  
Boston, MA 02110

New Hampshire

The Honorable John H. Lynch  
State House  
25 Capitol Street  
Concord, NH 03301

New Hampshire Public Utilities Commission  
21 South Fruit Street  
Suite 10  
Concord, NH 03301-2429

Rhode Island

The Honorable Donald L. Carcieri  
State House Room 115  
Providence, RI 02903

Rhode Island Public Utilities Commission  
89 Jefferson Boulevard  
Warwick, RI 02888

Vermont

The Honorable James Douglas  
109 State Street, Pavilion  
Montpelier, VT 05609

Vermont Public Service Board  
112 State Street, Drawer 20  
Montpelier, VT 05620-2701

**New England Governors  
and Utility Regulatory  
and Related Agencies**

**October 26, 2005**

Thomas B. Getz, President  
New England Conference of  
Public Utilities Commissioners, Inc.  
c/o NH Public Utilities Commission  
21 South Fruit Street, Suite 10  
Concord, NH 03301-2429

William M. Nugent  
Executive Director  
New England Conference of  
Public Utilities Commissioners, Inc.  
500 U.S. Route 1, Suite 21 C  
Yarmouth, ME 04096

Harvey L. Reiter, Esq.  
Counsel for New England Conference  
of Public Utilities Commissioners, Inc.  
c/o MORRISON HECKER  
1150 18th Street, NW, Suite 800  
Washington, DC 20036-3816

Power Planning Committee  
New England Governors Conference, Inc.  
76 Summer Street, 2nd Floor  
Boston, MA 02110

## **Attachment 5**

## MEMORANDUM

**TO:** Participants Committee Members and Alternates  
**FROM:** David T. Doot, Secretary  
**DATE:** October 28, 2005  
**RE:** **SUMMARY OF ACTIONS OF NEPOOL PARTICIPANTS COMMITTEE**

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We have summarized below the actions taken at special NEPOOL Participants Committee teleconference meeting held on Friday, October 21, 2005. The single agenda item for the special meeting was to consider the ISO's proposed revisions to Market Rule 1 (including changes to Appendices A, E and F and inclusion of a new Appendix I) to implement elements of its Winter 2005/2006 action plan addressing: (a) generator offer flexibility; (b) the elimination of allocation of Real-Time NCPC deviation charges to EETs; (c) posturing rules; and (d) the addition of a demand response supplemental incentive program. The revisions were considered separately by element and voted with the understanding that they would sunset on April 1, 2006, as reflected in new Appendix I as follows:

**a. Generator Offer Flexibility:** The Committee considered and approved the following motion:

RESOLVED, that the Participants Committee supports revisions to Market Rule 1 to implement the generator offer flexibility element of the ISO's Winter 2005/2006 Action Plan as recommended by the Markets Committee and circulated to the Committee in advance of this meeting, with such non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion was approved with 73.02% in favor (Generation Sector - 17.47%; Transmission Sector - 17.47%; Supplier Sector - 14.29%; Alternative Resources Sector - 6.33%;<sup>1</sup> Publicly Owned Entity Sector - 17.47%; and End User Sector - 0%. (See Vote 1 on the attached tabulation).

**b. Elimination of Allocation of Real-Time NCPC Deviation Charges to EETs:** The Committee considered and approved the following motion:

RESOLVED, that the Participants Committee supports revisions to Market Rule 1 to implement the element of the ISO's Winter 2005/2006 Action Plan that eliminates the allocation of Real-Time NCPC deviation charges to Emergency Energy Transactions, as recommended by the Markets Committee and circulated to the Committee in advance of this meeting, with such non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion was approved with 74.53% in favor (Generation Sector - 17.47%; Transmission Sector - 17.47%; Supplier Sector - 17.47%; Alternative Resources Sector - 4.67%;<sup>2</sup> Publicly Owned Entity Sector - 17.47%; and End User Sector - 0%. (See Vote 2 on the attached tabulation).

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<sup>1</sup> The AR Sector vote reflects the fact that the AR Sector did not have a Sector Quorum and the Renewable Generation Sub-Sector did not have a Sub-Sector Quorum.

<sup>2</sup> As with Vote 1, the AR Sector vote reflects the fact that the AR Sector did not have a Sector Quorum and the Renewable Generation Sub-Sector did not have a Sub-Sector Quorum. Because the AR Sector did not have a Sector Quorum, the Member Fixed Voting Share of the one Renewable Generation Resource Provider abstaining on Vote 2 was not reallocated to the remaining members of the AR Sector casting a vote on the motion.

- c. **Posturing Rules:** Consideration of the Posturing Rules was taken up in two motions. The first motion addressed only those revisions to the posturing rules that were unrelated to cost allocation. The second motion addressed cost allocation.

**First Motion on the Posturing Rules:** The following motion to consider only those revisions to the posturing rules that were unrelated to cost allocation was made:

RESOLVED, that the Participants Committee supports revisions to Market Rule 1 Sections III.F.2.6.2(a) and (b) recommended by the ISO and circulated to the Committee in advance of this meeting, with such non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

**Motion To Amend:** The Committee considered and approved without opposition (Braintree and Taunton abstaining) a motion to amend the first motion on the posturing rules to add the following understanding to the end of the motion:

it being understood that Resources who are postured as a result of this Rule change are not to be economically harmed because of that posturing and the ISO and the Markets Committee are to recommend as appropriate additional changes that may be necessary to reflect this conceptual agreement for effectiveness coincident with the change in the posturing rules.

The first motion on the posturing rules as amended was then unanimously approved with abstentions noted by BOC, CT OCC, NH OCA, UCS, Braintree and Taunton. (See Vote 4 on the attached tabulation).

**Second Motion on the Posturing Rules:** The following motion was then made to consider those revisions to the posturing rules that addressed cost allocation:

RESOLVED, that the Participants Committee supports revisions to Market Rule 1 Section III.F.3.1 recommended by the ISO and circulated to the Committee in advance of this meeting, with such non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

**First Motion To Amend:** The Committee considered and rejected a motion to amend the second motion on the posturing rules so that Real-Time Operating Reserve Credits associated with the posturing of facilities would be allocated and charged to Network Load. The first motion to amend failed with 46.92% in favor (Generation Sector - 17.47%; Transmission Sector - 2.50%; Supplier Sector - 14.29%; Alternative Resources Sector - 12.67%; Publicly Owned Entity Sector - 0%; and End User Sector - 0%). (See Vote 5 on the attached tabulation).

**Second Motion To Amend:** The Committee then considered and approved a motion to amend the second motion on the posturing rules to add the following understanding to the end of the motion:

it being understood that Real-Time Operating Reserve Credits associated with the posturing of facilities will not be allocated and charged to non-recallable exports and the ISO and the Markets Committee are to recommend as appropriate additional changes that may be necessary to reflect this conceptual agreement for effectiveness coincident with the change in the posturing rules.

The second motion to amend the posturing rules was then approved with 63.13% in favor (Generation Sector - 17.47%; Transmission Sector - 0%; Supplier Sector - 15.53%; Alternative Resources Sector - 12.67%; Publicly Owned Entity Sector - 17.47%; and End User Sector - 0%). (See Vote 6 on the attached tabulation).

The second motion on the posturing rules as amended was then approved with 82.27% in favor (Generation Sector - 6.99%; Transmission Sector – 17.47%; Supplier Sector – 13.10%; Alternative Resources Sector – 9.79%; Publicly Owned Entity Sector - 17.47%; and End User Sector – 17.47%. (See Vote 7 on the attached tabulation).

- d. **Demand Response Supplemental Incentive Program:** The following motion was then made to consider the addition of a demand response supplemental incentive program (“DRSIP”) to Market Rule 1:

RESOLVED, that the Participants Committee supports revisions to Market Rule 1 to implement the element of the ISO’s Winter 2005/2006 Action Plan that adds a demand response supplemental incentive program, as recommended by the Markets Committee and circulated to the Committee in advance of this meeting, with such non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

**First Motion To Amend:** The Committee considered and rejected a motion to amend the DRSIP to apply to Settlement only generators that chose the Self Scheduling option. The first motion to amend failed with 37.84% in favor (Generation Sector - 0%; Transmission Sector - 2.91%; Supplier Sector – 0%; Alternative Resources Sector – 0%; Publicly Owned Entity Sector – 17.47%; and End User Sector – 17.47%. (See Vote 8 on the attached tabulation).

**Second Motion To Amend:** The Committee then considered and rejected a second motion to amend the DRSIP to include within the DRSIP the costs of participation by Resources selected pursuant to the Southwest Connecticut GAP RFP process for the period December 1, 2005 through March 31, 2006. The second motion to amend failed with 19.02% in favor (Generation Sector - 0%; Transmission Sector – 5.82%; Supplier Sector – 0%; Alternative Resources Sector – 12.67%; Publicly Owned Entity Sector – 0.53%; and End User Sector - 0%. (See Vote 9 on the attached tabulation).

The main motion to consider the addition of a DRSIP to Market Rule 1 was then approved with 62.19% in favor (Generation Sector - 0%; Transmission Sector – 17.47%; Supplier Sector – 12.48%; Alternative Resources Sector – 12.67%; Publicly Owned Entity Sector – 2.12%; and End User Sector – 17.47%. (See Vote 10 on the attached tabulation).

- e. **Addition of Appendix I (Sunset Provisions):** The Committee unanimously supported by acclamation the inclusion of an Appendix I to Market Rule 1 that will list those provisions that will go into effect on April 1, 2006 after the sun-setting of the Market Rule amendments approved at the meeting.

**NEPOOL PARTICIPANTS COMMITTEE  
OCTOBER 21, 2005 SPECIAL TELECONFERENCE MEETING  
VOTE TALLY**

**TOTAL**

<b>SECTOR</b>	<b>Vote 1</b>	<b>Vote 2</b>	<b>Vote 3</b>	<b>Vote 4</b>	<b>Vote 5</b>	<b>Vote 6</b>	<b>Vote 7</b>	<b>Vote 8</b>	<b>Vote 9</b>	<b>Vote 10</b>
<b>GENERATION</b>	17.47	17.47	17.47	17.47	17.47	17.47	6.99	0.00	0.00	0.00
<b>TRANSMISSION</b>	17.47	17.47	17.47	17.47	2.50	0.00	17.47	2.91	5.82	17.47
<b>SUPPLIER</b>	14.29	17.47	17.47	17.47	14.29	15.53	13.10	0.00	0.00	12.48
<b>AR</b>	6.33	4.67	12.67	12.67	12.67	12.67	9.79	0.00	12.67	12.67
<b>PUBLICLY OWNED ENTITY</b>	17.47	17.47	17.47	17.47	0.00	17.47	17.47	17.47	0.53	2.12
<b>END USER</b>	0.00	0.00	17.47	17.47	0.00	0.00	17.47	17.47	0.00	17.47
<b>% IN FAVOR</b>	73.02	74.53	100.00	100.00	46.92	63.13	82.27	37.84	19.02	62.19

**GENERATION SECTOR**

<b>Participant Name</b>	<b>Vote 1</b>	<b>Vote 2</b>	<b>Vote 3</b>	<b>Vote 4</b>	<b>Vote 5</b>	<b>Vote 6</b>	<b>Vote 7</b>	<b>Vote 8</b>	<b>Vote 9</b>	<b>Vote 10</b>
ANP Funding I, LLC	F	F	F	F	F	F	A	O	O	O
Boston Generating, LLC	A	F	F	F	F	F	F	A	O	A
Consolidated Edison Energy, Inc.	F	F	F	F	F	F	A	A	A	O
Dominion Energy Marketing, Inc.	F	F	F	F	F	A	O	A	A	A
FPL Energy LLC	F	F	F	F	F	F	O	A	A	A
Lake Road Generating Company, LP	F	F	F	F	F	F	F	A	A	A
Mirant New England, LLC	F	F	F	F	F	F	A	A	A	A
TransCanada Power Marketing Ltd.	F	F	F	F	F	F	O	A	O	O
IN FAVOR (F)	7	8	8	8	8	7	2	0	0	0
OPPOSED (O)	0	0	0	0	0	0	3	1	3	3
TOTAL VOTES	7	8	8	8	8	7	5	1	3	3
ABSTENTIONS (A)	1	0	0	0	0	1	3	7	5	5

**NEPOOL PARTICIPANTS COMMITTEE  
OCTOBER 21, 2005 SPECIAL TELECONFERENCE MEETING  
VOTE TALLY**

**TRANSMISSION SECTOR**

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7	Vote 8	Vote 9	Vote 10
Bangor Hydro-Electric Company	F	F	F	F	O	O	F	O	O	F
Boston Edison Company	F	F	F	F	O	O	F	O	O	F
Central Maine Power Company	F	F	F	F	O	A	F	O	O	F
New England Power Company	F	F	F	F	O	O	F	A	O	F
The United Illuminating Company	F	F	F	F	O	O	F	F	F	A
Northeast Utilities System Companies	F	F	F	F	F	O	F	O	F	F
Vermont Electric Power Company, Inc.	F	F	F	F	O	O	F	O		F
IN FAVOR (F)	7	7	7	7	1	0	7	1	2	6
OPPOSED (O)	0	0	0	0	6	6	0	5	4	0
TOTAL VOTES	7	7	7	7	7	6	7	6	6	6
ABSTENTIONS (A)	0	0	0	0	0	1	0	1	0	1

**SUPPLIER SECTOR**

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7	Vote 8	Vote 9	Vote 10
BOC Energy Services, Inc.	A	A	F	A	O	O	F	A	A	F
Constellation Energy Commodities Group	O	F	F	F	F	F	O	A	A	F
DC Energy, LLC	F	F	F	F	A	A	A	O	O	O
Edison Mission Marketing and Trading	F	F	F	F	F	F	A	A	A	A
El Paso Marketing, LP	F	F	F	F	F	F	F	O	O	F
Epic Merchant Energy, L.P.	A	F	F	F	F	A	F	A	A	A
Exelon Generation, LLC	F	F	F	F	A	F	F	A	A	A
H.Q. Energy Services (U.S.) Inc.	F	F	F	F	F	F	A	O	A	
LIPA	F	F	F	F	F	F	F	A	A	A
NRG Power Marketing, Inc.	F	F	F	F	F	F	A	O	O	O
PPL EnergyPlus, LLC	F	F	F	F	F	A	A			
Strategic Energy Ltd.	O	F	F	F	F	A	O	A	A	F
Unitil Corporation Participants Companies	F	F	F	F	O	F	F	O	O	F
IN FAVOR (F)	9	12	13	12	9	8	6	0	0	5
OPPOSED (O)	2	0	0	0	2	1	2	5	4	2
TOTAL VOTES	11	12	13	12	11	9	8	5	4	7
ABSTENTIONS (A)	2	1	0	1	2	4	5	7	8	4

**NEPOOL PARTICIPANTS COMMITTEE  
OCTOBER 21, 2005 SPECIAL TELECONFERENCE MEETING  
VOTE TALLY**

**PUBLICLY OWNED ENTITY SECTOR**

<b>Participant Name</b>	<b>Vote 1</b>	<b>Vote 2</b>	<b>Vote 3</b>	<b>Vote 4</b>	<b>Vote 5</b>	<b>Vote 6</b>	<b>Vote 7</b>	<b>Vote 8</b>	<b>Vote 9</b>	<b>Vote 10</b>
Ashburnham Municipal Light Plant	F	F	F	F	O	F	F	F	O	O
Belmont Municipal Light Department	F	F	F	F	O	F	F	F	O	O
Boylston Municipal Light Department	F	F	F	F	O	F	F	F	O	O
Braintree Electric Light Department	A	A	A	A	O	A	A	F	O	F
Chicopee Municipal Lighting Plant	F	F	F	F	O	F	F	F	O	O
Concord Municipal Light Plant	F	F	F	F	O	F	F	F	F	O
Conn. Municipal Electric Energy Cooperative	F	F	F	F	O	F	F	F	O	F
Danvers Electric Division	F	F	F	F	O	F	F	F	O	O
Georgetown Municipal Light Department	F	F	F	F	O	F	F	F	O	O
Groton Electric Light Department	F	F	F	F	O	F	F	F	O	O
Hingham Municipal Lighting Plant	F	F	F	F	O	F	F	F	O	O
Holden Municipal Light Department	F	F	F	F	O	F	F	F	O	O
Holyoke Gas & Electric Department	F	F	F	F	O	F	F	F	O	O
Hudson Light and Power Department	F	F	F	F	O	F	F	F	O	O
Hull Municipal Lighting Plant	F	F	F	F	O	F	F	F	O	O
Ipswich Municipal Light Department	F	F	F	F	O	F	F	F	O	O
Littleton Electric Light Department	F	F	F	F	O	F	F	F	O	O
Mansfield Municipal Electric Department	F	F	F	F	O	F	F	F	O	O
Marblehead Municipal Light Department	F	F	F	F	O	F	F	F	O	O
Mass. Municipal Wholesale Electric Company	F	F	F	F	O	F	F	F	O	O
Middleborough Gas and Electric Department	F	F	F	F	O	F	F	F	O	O
Middleton Municipal Electric Department	F	F	F	F	O	F	F	F	O	O
North Attleborough Electric Department	F	F	F	F	O	F	F	F	O	O
Paxton Municipal Light Department	F	F	F	F	O	F	F	F	O	O
Peabody Municipal Light Plant	F	F	F	F	O	F	F	F	O	O
Reading Municipal Light Department	F	F	F	F	O	F	F	F	O	O
Rowley Municipal Lighting Plant	F	F	F	F	O	F	F	F	O	O
Shrewsbury's Electric & Cable Operations	F	F	F	F	O	F	F	F	O	O
Sterling Municipal Electric Light Department	F	F	F	F	O	F	F	F	O	O
Taunton Municipal Lighting Plant	A	A	A	A	O	A	A	F	O	F
Templeton Municipal Lighting Plant	F	F	F	F	O	F	F	F	O	O
Vermont Public Power Supply Authority	A	F	F	F	O	F	F	F	A	F
Wakefield Municipal Gas and Light Department	F	F	F	F	O	F	F	F	O	O
West Boylston Municipal Lighting Plant	F	F	F	F	O	F	F	F	O	O
Westfield Gas & Electric Light Department	F	F	F	F	O	F	F	F	O	O
IN FAVOR (F)	31	32	32	32	0	32	32	34	1	4
OPPOSED (O)	0	0	0	0	34	0	0	0	32	29
TOTAL VOTES	31	32	32	32	34	32	32	34	33	33
ABSTENTIONS (A)	3	2	2	2	0	2	2	0	1	0

**NEPOOL PARTICIPANTS COMMITTEE  
OCTOBER 21, 2005 SPECIAL TELECONFERENCE MEETING  
VOTE TALLY**

**ALTERNATIVE RESOURCES SECTOR**

<b>Participant Name</b>	<b>Vote 1</b>	<b>Vote 2</b>	<b>Vote 3</b>	<b>Vote 4</b>	<b>Vote 5</b>	<b>Vote 6</b>	<b>Vote 7</b>	<b>Vote 8</b>	<b>Vote 9</b>	<b>Vote 10</b>
<b>Renewable Generation Sub-Sector</b>										
Calpine Energy Services, LP	F	A	F	F	F	F	F	A	F	A
Gas Recovery Systems, Inc.			F	F	A	A	F	O	F	F
<b>Distributed Generation Sub-Sector</b>										
Pinpoint Power LLC	F	F	F	F	F	A	O	A	F	A
Seneca Energy II, LLC			F	F	A	A	F	O	F	F
<b>Load Response Sub-Sector</b>										
Conservation Services Group			F	F	A	A	F	O	F	F
EnerNOC, Inc.	F	F	F	F	F	A	A	A	F	F
IN FAVOR (F)	3	2	0	6	3	1	4	0	6	4
OPPOSED (O)	0	0	0	0	0	0	1	3	0	0
TOTAL VOTES	3	2	0	6	3	1	5	3	6	4
ABSTENTIONS (A)	0	1	0	0	3	5	1	3	0	2

**NEPOOL PARTICIPANTS COMMITTEE  
OCTOBER 21, 2005 SPECIAL TELECONFERENCE MEETING  
VOTE TALLY**

**END USER SECTOR**

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7	Vote 8	Vote 9	Vote 10
Associated Industries of Massachusetts (O)	A	A	F	F	O	A	F	A	O	F
CT, State of, Office of Consumer Counsel (O)	A	A	F	A	O	A	F	A	A	A
Harvard Dedicated Energy Limited (O)	O	A	F	F	O	O	F			
Industrial Energy Consumer Group (O)	O	A	F	F	O	A	F	F	O	F
J&L Electric (S)	A	A	F	F	O	A	F	F	O	F
Maine Skiing, Inc. (O)	A	A	F	F	O	A	F	F	O	F
Mead Oxford Corporation (L)	A	A	F	F	O	A	F	F	O	F
New Hampshire Office of Consumer Advocate (O)	O	A	F	A	O	O	F	A	A	A
PowerOptions, Inc. (O)	O	A	F	F	O	O	F	F	A	F
Praxair, Inc. (L)	O	A	F	F	O	O	F	F	A	F
Silkman, Richard (S)	A	A	F	F	O	A	F	F	O	F
Texas Instruments (L)	O	A	F	F	O	O	F	A	A	A
The Energy Consortium (O)	O	A	F	F	O	O	F	A	A	A
The Energy Council of Rhode Island (TEC-RI) (O)	O	A	F	F	O	O	F	A	A	A
Union of Concerned Scientists (O)	A	A	F	A	A	A	A	A	A	A
IN FAVOR (F)	0	0	15	12	0	0	14	7	0	8
OPPOSED (O)	8	0	0	0	14	7	0	0	6	0
TOTAL VOTES	8	0	15	12	14	7	14	7	6	8
ABSTENTIONS (A)	7	15	0	3	1	8	1	7	8	6

## **Attachment 6**

Post Katrina and Rita  
Outlook on Fuel Supply Adequacy and  
Bulk Power Security in New England

*prepared for*



October 6, 2005

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## Executive Summary

Following Hurricane Katrina, ISO New England Inc. (ISO-NE) asked Levitan & Associates, Inc. (LAI) to conduct an analysis of the impact of the hurricane on fuel supply availability and fossil fuel prices in New England. Research objectives were expanded later in September when Hurricane Rita entered the Gulf of Mexico (GoM). The results of this assessment will be used by ISO-NE in determining system planning responses to possible natural gas shortages during the upcoming heating season, November 2005 through March 2006 (the "2005/06 Heating Season").

Over the last six years, New England has become reliant on natural gas to produce electricity. Following utility sales of power plants to investors in the late 1990's, the addition of approximately 10,000 megawatts (MW) of gas-fired generation has contributed significantly to the region's growing dependence on natural gas. Today, more than 40% of the region's installed generating capacity burns natural gas as the primary fuel source, up dramatically from about 17% in 1999. Roughly 40% of the total natural gas consumed in New England is used to produce electricity.

Last year, power plants that burn only natural gas set the wholesale electric market clearing price 55% of the time. Generators that burn gas or oil set the price 85% of the time. Since 2002, natural gas prices have more than tripled. Like all premium fossil fuels, over the last year natural gas prices have increased dramatically. Since Katrina made landfall on August 29, forward natural gas prices at the Henry Hub for January 2006 skyrocketed to over \$15.00 per million British thermal units (MMBtu).

As winter weather approaches, New England can anticipate greater pressure than normal on the cost of fuel and, in turn, wholesale electricity prices. It is expected that gas supply constraints likely to occur this winter will require increased reliance on oil for electricity generation, in particular, residual fuel oil. Therefore, gas and electric conservation initiatives are encouraged to help maintain reliability of the bulk electric power grid this heating season.

LAI's primary observations are as follows:

- Hurricanes Katrina and Rita caused most crude oil and natural gas production in the GoM to be temporarily shut-in. A small percentage of the GoM shut-in natural gas production may be permanently lost.
- During the 2005/06 Heating Season, it is likely that a significant amount of natural gas production, about 1 billion cubic feet per day (Bcf/d) -- perhaps more -- will not likely be available to pipelines serving the Atlantic seaboard. As a result, natural gas supplies are likely to be tight, thereby causing natural gas prices to remain at extremely high price levels throughout the heating season.
- Because a significant portion of New England's electricity supply is derived from natural gas, wholesale power prices in New England will remain high as well. The potential substitution of oil for natural gas for power production is not likely to substantially ease pressures on wholesale electricity prices.

- Approximately 15% of Gulf coast oil refining capacity has been significantly damaged. Most of this capacity should be back on-line by early in 2006. The loss of this refining capacity will likely keep gasoline, home heating oil (distillate fuel oil), jet and diesel fuel very expensive relative to the average prices experienced for these refined products over the past few years.
- New England has diverse natural gas supplies, including strong pipeline connections with Canada, and liquefied natural gas (LNG) that is imported mostly from Trinidad to the Distrigas terminal in Everett, MA. In order to assure reliable (gas) utility service during cold snaps, trucks transport a significant amount of LNG to much smaller satellite storage facilities throughout New England. Despite New England's pipeline connections with Canadian supply and reliance on LNG, New England still depends on GoM gas supplies. These supplies are transported by two interstate pipelines into New England. In light of the uncertainty about the time needed to restore GoM natural gas production, there is a significant chance that a chronic supply deficit will materialize during the 2005/06 Heating Season. Should such a supply deficit occur, it would adversely affect at least one, and, perhaps, both of the interstate pipelines serving southern New England this heating season. In such an event, gas-fired generators are sure to be disproportionately affected as a result of the "non-firm" character of their natural gas supply and transportation service, which is characteristic of merchant generation throughout New England.
- These uncertainties about natural gas supply and deliverability for power generation in during the 2005/06 Heating Season will heighten the region's dependence on oil-fired generation, in particular, residual fuel oil.
- From an electricity planning perspective, there is not likely to be enough premium fossil fuels, especially distillate fuel oil for home heating, to refill storage tanks for peaking units or combined cycle plants that are capable of burning this premium fuel during the 2005/06 Heating Season. There are a variety of logistical concerns and constraints on truck-transported distillate fuel oil shipments during cold snaps.
- While residual fuel oil can be burned in the older fleet of steam generation plants, it cannot be burned by any of the new, fuel-efficient combined cycle plants that have been added to the region's electricity grid since the late 1990's. Those fuel-efficient units that are permitted to burn fuel oil as a back-up fuel require the lighter distillate fuel oil rather than the heavier residual fuel oil. Other than for very brief intervals at coastal locations, we do not believe it is feasible to rely on significant amounts of distillate fuel oil for power generation during the 2005/06 Heating Season.
- Based on LAI's qualitative assessment:
  - Potential constraints on natural gas supply this heating season may be managed effectively by ISO-NE through increased use of oil-fired generation that burns residual fuel oil.
  - Residual fuel oil should be available (at high prices) by tanker or barge to coastal locations throughout the heating season.

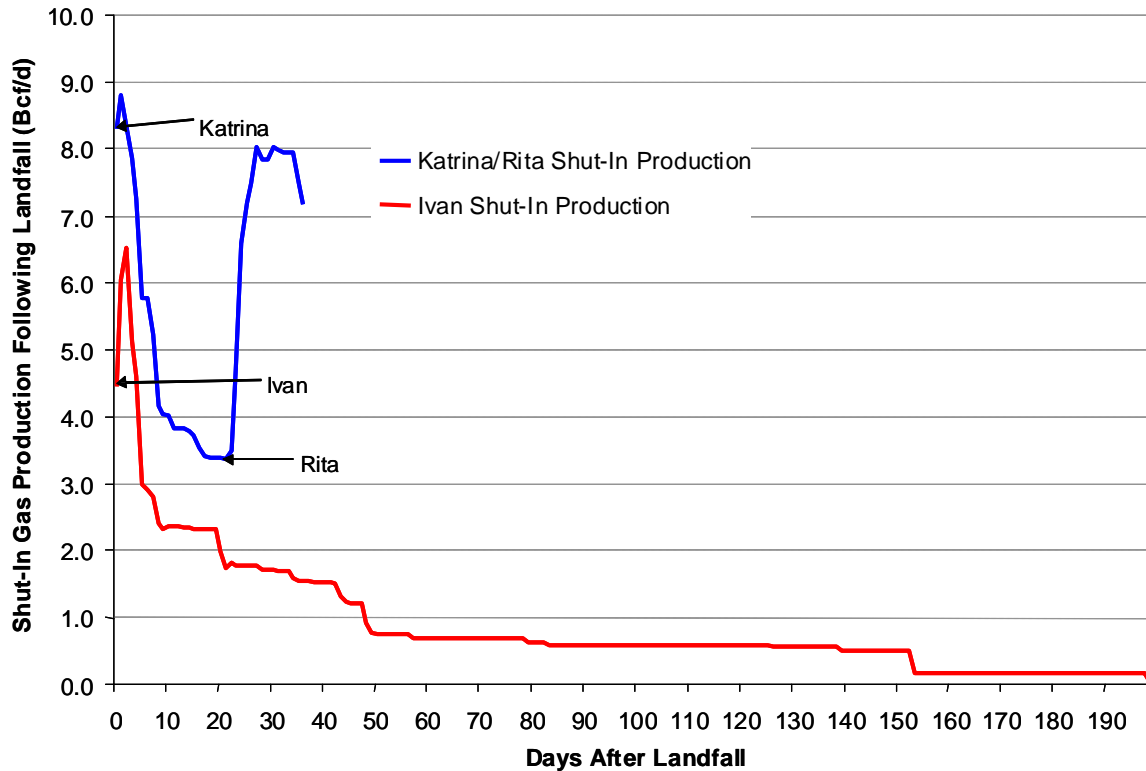
- Quick-start units located in Connecticut and northeast Massachusetts will require distillate fuel oil rather than natural gas to ensure power production during cold snaps. Trucking logistics to continually replenish distillate fuel oil inventories at inland generating plants during cold snaps appear daunting and would be detrimental to core (residential and commercial) heating customers.
  - Exploitation of gas pipeline line-pack by gas-fired power generators is ill-advised and potentially detrimental to core gas customers.
- In addition to increased reliance on fuel oil for electric generation, conservation initiatives – both gas-side and electric-side programs – may play an integral part in maintaining the region’s energy security this heating season. While high oil, natural gas and electricity prices are likely to temper demand, the conservation message should be reinforced through orchestrated media campaigns designed to turn thermostats down and to deter consumer behavior that increases peak electric demand during cold snaps.

# Report

## Hurricane Impacts

Hurricanes Katrina and Rita disrupted most of the natural gas and oil production in the GoM. Following Katrina, shut-in natural gas production peaked at more than 85% of Gulf offshore gas production. Prior to Rita's arrival in the GoM on September 20<sup>th</sup>, the amount of shut-in gas production had declined from 85% to around 35%. On Katrina's coattails, Rita resulted in approximately 8.0 Bcf/d of shut-in natural gas production, about 80% of total GoM production. This shut-in natural gas production equates to about 16% of total U.S. daily production. Shut-in oil supply amounted to 1.5 million barrels per day (BPD), nearly all of the crude oil extracted from the GoM. This production loss equates to about 28% of U.S. daily production. Lost refinery capacity in the Gulf Coast amounted to 2.5 million BPD, about 15% of the total U.S. capacity to refine crude oil into home heating fuel, gasoline, jet fuel, and other light-end products. As of October 6<sup>th</sup>, 80% of crude oil production and 66% of natural gas production in the GoM remains shut-in.

The industry's ability to restore gas production in the GoM following last summer's Hurricane Ivan as compared with Hurricanes Katrina and Rita is illustrated below.



Damage to the natural gas gathering infrastructure – the equipment necessary to render the gas “pipeline quality” – in the GoM and onshore may have been extensive, thereby causing a substantial loss in daily deliverability on major pipelines serving the Atlantic seaboard and mid-west U.S. This infrastructure is currently being surveyed to determine the extent of the damage, but the loss of equipment and the dislocation of personnel

onshore have delayed the process. Many onshore facilities reported relatively minor damage and are ready to resume operations, but are currently delayed until electric service can be fully restored. In the wake of Katrina and Rita, many pipeline companies experienced deep cuts in throughput, in particular, Williams' Transcontinental Pipeline Co. (Transco) and El Paso's Tennessee Gas Pipeline (Tennessee). After Katrina made landfall, Transco invoked emergency scheduling procedures in order to allocate limited gas supply across its route system from the Gulf of Mexico to New York City and Long Island. Transco now reports that most of its onshore systems are now capable of operating at pre-Katrina levels; however, Transco's operations remain subject to flow reductions due to shut-in gas production and off-line gas processing plants.

The Tennessee system also experienced a dramatic decline in daily deliverability across its major trunkline, emanating from the GoM and terminating in New England, although to its benefit, Tennessee continued to receive natural gas from Canada at its Niagara receipt point into New York. For the first time since its inception in the late 1980's, physical deliveries to the Henry Hub (Erath, LA.) were interrupted for twelve days following Rita as a result of extensive flooding and a loss of electricity supply. The pipeline that operates the Henry Hub was forced to declare *force majeure* – a legal provision that excuses performance when natural disasters occur. The loss of the Henry Hub is particularly noteworthy as this hub is the largest pooling point for natural gas trade in North America and serves as the basis for financial settlement of NYMEX natural gas futures. The *force majeure* at the Henry Hub was finally lifted for NYMEX physical deliveries and several of the pipeline interconnections at the Henry Hub on October 4<sup>th</sup>.

As of October 6th, more than a dozen natural gas processing plants remained off-line, mostly due to flooding and loss of power. Several major gas gathering facilities such as Williams' Cameron Meadows and Dynegey's Venice plant have suffered significant damage and are likely to be out-of-service beyond the end of October. Following Katrina, four refineries in Louisiana and Mississippi have not returned to operation. Seven other refineries in Louisiana and Texas suffered significant damage from Rita. These refineries account for about 15% of overall U.S. refining capacity. Many of these refineries are likely to remain shut down until the end of 2005. Damage to oil and gas production platforms has mostly affected older platforms representing less than 1% of GoM gas production. A number of the newer deepwater production facilities have also been significantly damaged. Most of these, with the likely exception of Chevron's capsized Typhoon production platform, are expected to return to production sometime next year. Katrina and Rita collectively pummeled nineteen offshore drilling rigs with a potential loss of five others. Based on LAI's preliminary assessment, it is likely that most of these damaged rigs will be returned to operation after repairs have been completed.

Major pipeline infrastructure additions served to cushion New England's overall exposure to gas supply constraints following Katrina and Rita. Lower gas consumption in September, a comparatively light load period for natural gas and electric power demand in New England, combined with gas supplies from western and Atlantic Canada as well as the Distrigas LNG terminal, enabled core and non-core gas demands to be met. However, some power plants in the Northeast switched from gas to fuel oil in response to the production shortage. Canadian gas supply is transported on Iroquois, Maritimes & Northeast (M&N), Tennessee's 200 Line across New York, and Portland Natural Gas Transmission System (PNGTS). Importantly, Duke-Energy's Texas Eastern Gas Pipeline Co. (TETCO) and its Algonquin Gas Transmission System (Algonquin) did

not experience a significant decrease in daily delivery capability despite TETCO's major reliance on supply from Texas, Louisiana, and the GoM. Provided the upstream producers and pipeline(s) do not experience outage constraints during the 2005/06 Heating Season, LAI does not expect any variance from the "business-as-usual" conditions this winter on pipelines that transport Canadian gas into New England.

September is typically a busy time for gas storage refill injections at conventional storage facilities located in Pennsylvania, West Virginia, Kentucky, and New York. During September and in the beginning of October, market participants have scrambled for additional gas supplies in order to keep pace with injection schedules at the major storage hubs serving New England. Monthly injections into total East storage following Katrina for the week of September 30th amounted to 35 Bcf, yielding working gas storage inventory levels in the East equal to 96% of last year's level and 101% of the 5-year average for storage at this time of year.

### **Natural Gas and Oil Price Outlook for 2005/06 Heating Season**

Prices for NYMEX natural gas futures soared following Katrina's landfall on August 29<sup>th</sup>: the January 2006 price has increased from \$10.71/MMBtu on August 23<sup>rd</sup> to \$15.15/MMBtu on October 4<sup>th</sup>. On October 4<sup>th</sup>, the 5-month NYMEX strip (from November 2005 through March 2006) was \$12.27/MMBtu as compared with \$9.49/MMBtu on August 23<sup>rd</sup>. **In LAI's view, expected tight natural gas supplies coupled with uncertainties surrounding the restoration of gas gathering infrastructure portend a continuation of the current scarcity (price) premium through the 2005/06 Heating Season.** The pattern of pre-Katrina gas price volatility is likely to continue and may appreciably increase in the event that colder-than-normal weather patterns occur early in the heating season, thereby triggering significant storage withdrawals from gas storage fields in Pennsylvania and New York. The loss of liquidity at the Henry Hub coupled with what LAI perceives to be a traders' bias in search of bad news, results in upward gas price pressure similar to the trend observed following Hurricane Ivan in September 2004. While the NYMEX strip shows a major reduction in natural gas prices of more than \$2.00/MMBtu following the 2005/06 Heating Season, in LAI's view the prospects are good for still deeper price reductions in Q2 2006 unless the heating season is much colder-than-normal up and down the Atlantic seaboard.

Crude oil and residual fuel oil prices have remained relatively stable at pre-Katrina levels. Despite the major loss of refinery capacity across the Gulf Coast, government authorized withdrawals from the Strategic Petroleum Reserve (SPR) and increased imports have tempered the run-up in oil prices. Nonetheless, prices for home heating oil jumped 10% following the hurricanes. Crude oil prices are usually impacted more by developments in the global oil markets rather than by U.S. production events -- U.S. crude oil production amounts to less than 30% of U.S. requirements. Increased imports of refined light-end products such as gasoline and heating oil should alleviate potential supply shortages, but are unlikely to put immediate downward pressure on market prices for transportation and home heating fuels.

## **Natural Gas/Oil Infrastructure Considerations in New England with Respect to Bulk Power Security**

### Gas Infrastructure

As of October 6<sup>th</sup>, the Minerals Management Service (MMS) does not know the extent of the destruction inflicted by Katrina and Rita on natural gas infrastructure in the GoM. As shown on page 4, examination of the shut-in pattern following Hurricane Ivan, a Category 3 hurricane when it made landfall, shows that shut-in gas production declined from 6.5 Bcf/d to 1.7 Bcf/d within 30 days. Post-Ivan shut-in gas production declined to 0.7 Bcf/d in 60 days and to 0.1 Bcf/d after 160 days. Absent more conclusive information regarding current damage to GoM gathering system infrastructure, the estimation of potential supply deficits in Q4 2005 and Q1 2006 must be considered speculative. **In light of the existing information, or lack thereof, LAI believes there is a significant chance of a chronic gas supply deficit this heating season on one or more pipelines that traditionally depend on gas supplies from the GoM.** Prior hydraulic analyses conducted by LAI for ISO-NE indicate that significant gas supply deficits cannot be offset by increased interconnect flows within New England's borders or (sustained) withdrawals from natural gas storage facilities in the Northeast to serve the gas-fired power generation sector.

Tennessee's reliance on Gulf Coast gas supply has the potential to impair its ability to maintain adequate pressure and flow across a portion of its route system serving southern New England, in particular, Connecticut and Rhode Island. At this time, Tennessee's ability to mitigate potential operating problems by moving gas south from Agawam MA, increasing interconnect flows with neighboring pipelines, or increasing its receipt of natural gas from the Distrigas LNG plant are not known. While Algonquin has not reported any significant diminution in gas supply injections, potential supply deficits in the GoM have the potential to adversely impact Algonquin, thereby potentially exacerbating typical operating constraints across its mainline in Connecticut and Massachusetts during the peak heating season. Algonquin's ability to mitigate potential operating problems by increasing interconnect flows with Iroquois and M&N, or increasing its receipt of natural gas from the Distrigas LNG plant for deliveries across the mainline via displacement is also unknown. Because New England's gas-fired generators are largely reliant on secondary firm or interruptible gas transportation contracts, if operating problems arise on Tennessee and/or Algonquin, it is highly likely that New England's power generators would be the first to experience scheduling constraints. One exception would be the new Mystic (8 & 9) Station outside Boston. Some generators have firm transportation rights for a portion of their maximum daily fuel requirements, but this number (approximately 3,000 MW) is a minority portion of the total new generation (over 10,000 MW) added to New England's power grid over the last six years. As experienced during the January 2004 Cold Snap and projected once again for the 2005/06 Heating Season, the willingness of these gas-fired power generators to commit to energy production in ISO-NE's day-ahead market is largely untested.

### Fuel Oil Infrastructure

New England is the second largest regional consumer of heating oil in the U.S., yet it is not connected to any oil pipelines that transport products from Gulf Coast and mid-Atlantic refineries. This complete reliance on (liquid) imports, both domestic and foreign,

makes the region vulnerable to supply-chain distribution events. Reliance on marine transportation also increases the cost of all petroleum products. Most fuel oil is transported to New England's borders via tankers or barges except in Vermont where rail transportation is necessary. Within New England, there are three pipelines that ship refined products to market centers: New Haven, CT to Springfield, MA; East Providence, RI to Springfield, MA; and, Portland, ME to Bangor, ME.

Distillate fuel oil and residual fuel oil are delivered primarily to Boston, New Haven, Portsmouth, Portland and Bridgeport and then trucked or transported by rail to inland power plants. Most of the region's power plants at coastline locations have residual and distillate fuel oil delivered directly by barges or tankers. Boston is the dominant harbor in New England in spite of physical constraints such as the depth of the channel, the width of the waterway and the narrow span of the Chelsea Street Bridge, which limits the size of entering tankers. In addition to refineries in the U.S. Gulf and mid-Atlantic, fuel oil cargoes originate from Canada, the Virgin Islands, and many other exporting countries. 80% of New England's residual fuel oil supplies are sourced from domestic refineries, the remainder is imported from a variety of countries, including Colombia, the United Kingdom, Aruba, Brazil, Trinidad and Tobago, Netherlands, Russia, Peru, Republic of Korea, Ecuador, Saudi Arabia and Germany, among others. More than 70% of New England's annual residual fuel oil use is for electricity generation in the region's aged fleet of steam turbine generators.

New England's heating customers remain primarily dependent on distillate oil rather than natural gas. Most of New England's distillate fuel oil is sold to residential customers. Only about 1% or approximately 600,000 barrels of the region's distillate oil use has historically been used for the generation of electricity. The Northeast Home Heating Oil Reserve consists of 2 million barrels of oil stored in New Jersey, Connecticut, and Rhode Island. No similar home heating oil reserves are located in Massachusetts, New Hampshire, Maine or Vermont. These reserves provide Northeast oil consumers with about a 10-day supply during the heating season. Furthermore, the business practice of just-in-time inventories along with more stringent environmental laws have resulted in a decline of more than 10% in regional storage capacity over the last fifteen years.

During cold snaps, both road and marine transportation are subject to physical constraints caused by icy conditions. We understand that oil distributors are often challenged to redeliver distillate fuel oil from terminals to end-users. There are many substantial limitations that complicate the redelivery of distillate oil during the peak heating season, in particular, the number of available trucks and drivers. Oil distributors, like gas utilities, seek to assure reliable service to residential and commercial heating customers. During cold snaps, LAI views with skepticism the ability to continually replenish distillate oil inventories to preserve the availability of quick-start generation capability in transmission constrained zones such as Connecticut and Northeast Massachusetts. About 19% or approximately 6,550 MW of New England's overall generation fleet has actual back-up fuel capability. For those units, the average on-site storage capacity is roughly 23,300 barrels, less than three days of supply at full power output. Approximately 8,500 GWh of winter generation is permitted to burn fuel oil; however, about one-third of this amount can be generated using oil only when natural gas is deemed to be "*unavailable*".

During the 2005/2006 Heating Season, LAI believes power plants located on the coast will be able to obtain the necessary residual fuel oil deliveries by tanker or barge. There

is about 16.3 million barrels of on-site residual fuel oil storage capability in New England. This amount corresponds to about 65% of the amount of residual fuel oil sold for electricity generation.

### **Key Observations & Findings**

- The total anticipated natural gas production losses for 2005 are likely to exceed 300 Bcf. About 1 Bcf/d of GoM production may be unavailable this winter -- assuming no additional hurricanes in October. Substantial loss of offshore gas gathering capacity is likely to continue through the end of 2005, thereby causing a significant supply deficit on major pipelines dependent on GoM production.
- The loss of oil refinery capacity in the Gulf portends tight distillate supplies and very high prices at least through the 2005/06 Heating Season. Crude and fuel oil production losses can be mitigated by increased imports, albeit at high incremental costs. Wholesale electric energy prices in New England are likely to be linked to the high cost of fuel oils and natural gas.
- Increased natural gas imports from western and Atlantic Canada as well as LNG from Distrigas are unlikely to *significantly* replace lost gas production from the GoM on a sustained basis. Increased natural gas withdrawals from major storage fields at Dawn, Ellisburg, Leidy, and other Columbia / Dominion storage facilities are predominantly for core gas markets and should be considered unavailable to New England's gas-fired power generators.
- Increased interconnect gas pipeline flows at Wright (NY), Brookfield (CT), Shelton (CT) and/or Mendon (MA) may alleviate peak-day gas supply constraints, but are unlikely to be sustainable throughout the entire heating season to assure quick-start (gas turbine) or combined cycle operations, particularly in Connecticut. Because most gas-fired generators are not contracted for firm pipeline capacity, when the system is congested or experiencing flow day constraints, a chronic supply deficit is likely to disproportionately affect non-core shippers on Tennessee and, conceivably, Algonquin.