NEPOOL

ISO New England

June 19, 2001

VIA HAND DELIVERY

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: New England Power Pool and ISO New England Inc.
FERC Docket No. ER01- -000
Filing of Standard Market Design Document

Dear Secretary Boergers:

Pursuant to Section 205 of the Federal Power Act, the New England Power Pool ("NEPOOL" or the "Pool") Participants Committee[1] and ISO New England Inc. ("ISO-NE" or the "ISO") (collectively, the "Joint Filers") hereby jointly file an original and six (6) copies of a document entitled "Standard Market Design Document," which is included as Attachment 1 of this filing (the "SMD Document"). The SMD Document reflects the substance of the standard market design ("SMD") for New England, is consistent with both NEPOOL's and the ISO's alternative filings of SMD, and is drafted not to implicate the underlying issues that have resulted in alternative SMD filings by the two organizations. As described in greater detail in this transmittal letter, the Joint Filers request that the Commission issue an order on or before August 1, 2001, accepting the SMD Document as a rate schedule for the New England markets to become effective on August 1, 2001 for service rendered on and after the CMS/MSS Effective Date. Further, in light of this joint filing, the Joint Filers each request that the Commission extend to September 15, 2001, the time interested persons have to submit comments and/or protests to two alternative SMD filings that are now pending before the Commission in Docket Nos. ER01-2192-000, EL01-85-000, and ER01-2223-000, and to consolidate those proceedings.

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[1] Capitalized terms used but not defined in this letter are intended to have the same meaning given such terms in Section 1 of the Restated New England Power Pool Agreement (the "Restated NEPOOL Agreement" or "Agreement"), Section 1 of the Restated NEPOOL Open Access Transmission Tariff ("NEPOOL Tariff" or "Tariff") or Section 1 of the NEPOOL Market Rules and Procedures ("Market Rules" or "Rules").

I. BACKGROUND

The Joint Filers have prepared and jointly filed the SMD Document to permit an expeditious and, they hope, uncontested order accepting the substance of SMD. The history of the development of SMD to date is covered extensively in filings by the Joint Filers and others in Docket Nos. ER01-2115-000, ER01-2223-000 and ER01-2192-000 and EL01-85-000.[2] By way of brief summary, on May 22, 2001, NEPOOL submitted an Informational Filing and Request for Order Regarding Standard Market Design – CMS/MSS, which was docketed in ER01-2115-000 (the "Informational Filing").[3] The Commission issued a notice of that filing on May 29, 2001, setting June 12, 2001 as the date for filing comments, protests and interventions. See 66 Fed. Reg. 30,180 (2001). The ISO filed a limited protest with respect to the Informational Filing. NEPOOL subsequently amended the Informational Filing on June 7, 2001 to withdraw any request for an expedited order from the Commission. A number of other filings also have been made in Docket No. ER01-2115-000.

On May 31, 2001, the ISO filed Market Rule 1X and a request that the Commission order related changes to the Restated NEPOOL Agreement and the Tariff (the "ISO Filing"). The Commission assigned that filing Docket Nos. ER01-2192-000 and EL01-85-000. The Commission issued a notice of the ISO Filing on June 12, 2001, setting June 21, 2001 as the date for filing comments, protests and interventions. See 66 Fed. Reg. 32,803 (2001).

On June 4, 2001, NEPOOL filed the Seventy-Fifth Agreement Amending New England Power Pool Agreement (the "Seventy-Fifth Agreement", and together with the Informational Filing and the ISO Filing, the "SMD Filings") which would amend the NEPOOL arrangements to include a new schedule, the SMD Schedule. The Commission assigned that filing Docket No. ER01-2223-000 and issued notice of the filing on June 7, 2001, setting June 25, 2001 as the date for filing comments, protests and interventions. See 66 Fed. Reg. 32,345 (2001).

The substantive provisions of the ISO Filing that reflect SMD are contained in a document labeled Market Rule 1X; the substantive provisions of NEPOOL's filing of the Seventy-Fifth Agreement that reflect SMD are contained in a document labeled as the SMD Schedule. Aside from the labeling of these two documents, they are identical in substance. The SMD Document which is included with this filing as Attachment 1 reflects all of the common substantive provision of Market Rule 1X and the SMD Schedule.

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[2] Joint Filers request that to the extent materials submitted in the SMD Filings are necessary or useful to the Commission in considering the materials included herewith, that such materials be incorporated by reference in this proceeding pursuant to the Commission's Regulations. See 18 C.F.R. § 35.19 (2001).

[3] Both the Informational Filing and ISO New England Inc.'s initial response to that filing were submitted in Docket Nos. EL00-62-000 et al. The Commission re-docketed the Informational Filing in Docket No. ER01-2115-000, and on June 4, 2001 the ISO re-filed its response to the Informational Filing in Docket No. ER01-2115-000.

Under the Interim Independent System Operator Agreement (the "ISO Agreement") between NEPOOL and the ISO, the ISO has authority in certain defined circumstances to create and amend Market Rules unilaterally but does not have such authority to amend unilaterally the Restated NEPOOL Agreement, NEPOOL Tariff or any schedules thereto. Accordingly, amendments to such arrangements, if not approved by NEPOOL, could only be achieved pursuant to filings under Section 206 of the Federal Power Act. As a result, the labeling of the document containing the SMD provisions may affect the process in the future for amending that document if NEPOOL does not approve changes that are recommended by the ISO.

As evidenced by the SMD Filings, there is not agreement among the ISO and Participants concerning the appropriate form to reflect the substance of SMD. There is also disagreement over the authority the parties had to file SMD initially and should have to amend the SMD provisions in the future. These disagreements are manifest in part by the choice between a Market Rule on the one hand and a Schedule to the Restated NEPOOL Agreement and NEPOOL Tariff on the other.

II. JOINT REQUEST FOR EXPEDITED COMMISSION SMD ORDER AND DEFERRAL OF UNDERLYING GOVERNANCE DISPUTE

As indicated above, the Joint Filers request that the Commission approve the SMD Document on or before August 1 and extend to September 15, 2001 the date interested persons have to file comments or protests in the dockets relating to the pending SMD Filings. These requests are made because the ISO and all Participants are unanimous in their support of the substance of SMD. They do not want to delay or jeopardize final Commission action on SMD because of disagreements over the governance of NEPOOL and the authority of the ISO as they affect the design and implementation of the New England electric markets. If the Commission issues a single order addressing both SMD and those issues, that order may be challenged and could slow the ISO's implementation of SMD. The ISO has indicated that it requires rapid approval of SMD to permit software development to implement SMD, but the SMD Document will not take effect until the CMS/MSS Effective Date.

Issues relating to the future scope of authority of the ISO are currently pending in the RTO proceedings relating to the New England region (Docket Nos. RT01-86-000 and RM99-2-000) and in a complaint proceeding in Docket No. EL01-39-000. In addition, the Commission issued on June 13, 2001 an order in Docket Nos. EL00-62-000 <u>et al.</u> that requires changes to provisions of the ISO Agreement and the Restated NEPOOL Agreement that relate to the ISO's authority to develop Market Rules and might otherwise impact this matter. Commission action in these other pending proceedings can have a profound impact on, or be dispositive of, the governance and authority issues raised by the alternative filings.

Deferring litigation of these issues until September 15, 2001 allows time for the parties to determine whether there is or remains disagreement over the governance and authority issues for SMD in light of any action that the Commission may take in other pending proceedings before then. In addition, it allows the Commission during the 60-day notice period to focus solely on the substance of the SMD provisions, for which there is unanimous support in New England, without being required in the same time frame to address the unresolved governance and authority issues. Deferral of litigation on these contested issues also allows the parties to focus their energies now on defining details of SMD and moving toward implementation.

Given the requested effective dates for the above-mentioned SMD filings, to the extent those SMD Filings were submitted pursuant to Section 205 of the Federal Power Act, the Commission must act on them within 60 days of the date of filing unless the filing entity agrees to deferral of such action. To support the relief requested, both NEPOOL and the ISO request that the Commission not act on SMD Filings until after September 15, 2001, the date when comments, interventions and protests are requested to be due on such filings, and that it act thereafter expeditiously no later than November 15, 2001.

Given the dates established by the Commission for comments, intervention and protests on the ISO Filing and NEPOOL's filing of the Seventy-Fifth Agreement, deferral of litigation to achieve the desired objectives would require that amended notices in the captioned proceedings be issued no later than Wednesday, June 20, 2001. Otherwise, entities interested in addressing the ISO Filing may feel compelled to address all issues on June 21, 2001, to ensure they do not lose their opportunity to express their views on such issues. Accordingly, for the convenience of the Commission, a draft form of amended notice for Docket Nos. ER01-2192-000 and EL01-85-000 is included as Attachment 3 to this transmittal letter and a draft form of amended notice for Docket No. ER01-2223-000 is included as Attachment 4. This transmittal has been provided electronically to all Participants, and via overnight courier to all non-Participant Transmission Customers, state regulatory authorities and governors for the six New England states. In addition, immediately upon receipt, NEPOOL will circulate electronically any amended notice issued in the pending dockets for the SMD Filings.

III. SUPPORTING INFORMATION

This filing changes the form but not the substance of two alternative filings that are pending before the Commission to approve SMD. The ISO included with its SMD Filing the information it believed was necessary to support its filing. NEPOOL included with its SMD Filing the information it believed was necessary to support its filing. Those materials that explain the substance of Market Rule 1X and the SMD Schedule are hereby incorporated by reference in the proceeding as support for the SMD Document. All the entities receiving the SMD Filings, which include all Participants, all non-Participant Transmission Customers, and the governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, have also been served with copies of the instant filing. In accordance with the requirements of Section 35.8 of the Commission's regulations, a draft form of notice for this filing, which is suitable for publication in the Federal Register, is included as Attachment 2. In addition, a diskette containing this form of notice, as well as the form of amended notices reflected in Attachments 3 and 4, which are discussed above, are included with this filing.

Correspondence and communications regarding this filing should be addressed to the Chair of the NEPOOL Participants Committee and the undersigned as follows:

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Please acknowledge receipt of this filing by date stamping and returning the extra copy of this transmittal letter with our courier.

Respectfully submitted,

New England Power Pool
Participants Committee

By: David T. Doot /bbs
David T. Doot, Secretary

ISO New England Inc.

By: Mary C. Hain /bbs
Mary C. Hain
Its Counsel

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ATTACHMENT 1

STANDARD MARKET DESIGN DOCUMENT

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NEPOOL STANDARD MARKET DESIGN

1. MARKET OPERATIONS

1.1 Introduction.

This Document sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the NEPOOL Market within the NEPOOL Control Area. This Document addresses each of the three time frames pertinent to the daily operation of the NEPOOL Market: Prescheduling, Scheduling, and Dispatch.

1.2 [Reserved.]

1.3 Definitions.

1.3.1 Existing Definitions.

Unless otherwise provided for in Section 1.3.2 of this Document, capitalized terms used but not defined in this Document are as defined in the NEPOOL Filed Documents.

1.3.2 New and Modified Definitions.

For purposes of this Document, the following capitalized terms shall have the meanings set forth below.

"Bilateral Transaction" as defined in Section 1.13 of the Agreement is a transaction, including a Firm Contract, System Contract, Load Asset Contract or other contract, between two or more Participants submitted for the transfer of Settlement Obligations in accordance with the Market Rules with respect to Installed Capability, Energy at one or more Locations within the NEPOOL Control Area, Operating Reserve and/or AGC or Regulation. When used in the plural form, it may be any or all such arrangements or combinations thereof, as the context requires.

"**Buyer**" shall mean a Participant who is buying in the NEPOOL Market or a Transmission Customer, as the context requires. There are Internal Buyers, External Buyers, and Transmission Customers.

"**Cancellation Fee**" is defined in Section 1.10.2(d).

"**Congestion Charge**" shall mean a charge attributable to the increased cost of Energy delivered at a given load Location when the transmission system serving that load Location is operating under constrained conditions, which shall be calculated and allocated as specified in Section 5.1 of this Document.

"**Congestion Component**" is the component of the Nodal Price that reflects the marginal cost of Congestion at a given Node or External Node relative to the Reference Node. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the Nodal Prices that comprise the Zonal Price and Hub Price averaged or weighted in the same way that Nodal Prices are averaged or weighted to determine the Zonal Price and Hub Price, respectively.

"**Congestion Cost**" on and after the CMS/MSS Effective Date, is the cost of Congestion as measured by the difference between the Congestion Components of the Locational Prices at different Locations and/or Reliability Regions on the NEPOOL Transmission System.

"**Control Area**" is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(i) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(ii) maintain scheduled interchange with other Control Areas, within the limits of Accepted Electric Industry Practice;

(iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the applicable regional reliability council or the NERC; and

(iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

"**Day-Ahead Adjusted Generation Obligation**" is defined in Section 3.2.1(a)(iv).

"**Day-Ahead Adjusted Load Obligation**" is defined in Section 3.2.1(a)(iii).

"**Day-Ahead Congestion Revenue**" is defined in Section 3.2.1(f).

"**Day-Ahead Energy Market**" shall mean the schedule of commitments for the purchase or sale of Energy, payment of Congestion Charges, and payments for Marginal Losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section 1.10 of this Document.

"**Day-Ahead Energy Market Charge/Credit**" is defined in Section 3.2.1(d).

"**Day-Ahead Generation Obligation**" is defined in Section 3.2.1(a)(ii).

"**Day-Ahead Load Obligation**" is defined in Section 3.2.1(a)(i).

"**Day-Ahead Locational Adjusted Net Interchange**" is defined in Section 3.2.1(a)(v).

"**Day-Ahead Marginal Loss Charges and Credits**" is defined in Section 3.2.1(h).

"**Day-Ahead Marginal Loss Revenue**" is defined in Section 3.2.1(g).

"**Day-Ahead Prices**" shall mean the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

"**Decrement Bid**" shall mean a bid to purchase Energy at a specified Location in the Day-Ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

"**Dispatch Rate**" shall mean the control signal, expressed in dollars per megawatt-hour or megawatts, calculated and transmitted to direct the output level of all generation Resources dispatched by the ISO in accordance with the Offer Data.

"**Eligible FTR Bidder**" has the meaning specified in Schedule 14 to the Tariff.

"**Energy**" as defined in Section 1.41 of the Agreement is electrical energy, measured in kilowatthours or megawatthours.

"**External Buyer**" shall mean a Transmission Customer taking Point-to-Point Transmission Service under the Tariff.

"**External Resource**" shall mean a generation resource located outside the metered boundaries of the NEPOOL Control Area.

"**Financial Transmission Right (FTR)**" shall mean a financial instrument that evidences the rights and obligations specified in Section 14 of the Tariff and Section 5.2 of this Document.

"**Generator Forced Outage**" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an emergency or threatened emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the NEPOOL Manuals and ISO Administrative Procedures. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

"**Generator Maintenance Outage**" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the NEPOOL Manuals and ISO Administrative Procedures.

"**Generator Planned Outage**" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the ISO in accordance with the NEPOOL Manuals and ISO Administrative Procedures.

"**Good Utility Practice**" is any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

"**ICAP Resources**" shall mean a Resource or portion thereof that has been designated by a Participant, in accordance with the NEPOOL Manuals, to meet its Installed Capability responsibility.

"**Increment Bid**" shall mean an offer to sell Energy at a specified Location in the Day-Ahead Energy Market. An accepted Increment Bid results in scheduled generation at the specified Location in the Day-Ahead Energy Market.

"**Internal Buyer**" shall mean a Participant making Energy purchases in the NEPOOL Market for ultimate consumption by end-users inside the NEPOOL Control Area that are served by Regional Network Service.

"ISO" shall mean ISO New England Inc.

"**ISO Administrative Procedures**" shall mean procedures adopted by the ISO to fulfill its responsibilities to apply and implement NEPOOL System Rules.

"**Location**" as defined in Section 1.87 of the Agreement is a Node, External Node, Load Zone or Hub.

"**Locational Marginal Price**" or "**LMP**" as defined as Locational Price in the Agreement and Schedule 13 of the Tariff is the price of Energy at a Location or Reliability Region, calculated in accordance with the Agreement and Schedule 13 of the Tariff. The Locational Price for a Node is the Nodal Price at that Node; the Locational Price for an External Node is the Nodal Price at that External Node; the Locational Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Price for a Hub is the Hub Price for that Hub.

"**Lost Opportunity Cost**" shall have the meaning specified in Section 3.2.2.

"**Market Operations Center**" shall mean the equipment, facilities and personnel used by or on behalf of a Participant to communicate and coordinate with the ISO in connection with transactions in the NEPOOL Market or the operation of the NEPOOL Control Area.

"Maximum Generation Emergency" shall mean an emergency declared by the ISO in accordance with the procedures set forth in the NEPOOL Manuals and ISO Administrative Procedures.

"**Minimum Generation Emergency**" shall mean an emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the emergency.

"**NEPOOL**" is the New England Power Pool, the power pool created under and governed by the Restated NEPOOL Agreement, and the entities collectively participating in the New England Power Pool as Participants.

"**NEPOOL Control Area**" as defined in Section 1.102 of the Agreement is the integrated electric power system to which a common Automatic Generation

Control scheme and various operating procedures are applied by or under the supervision of the System Operator in order to:

(i) match, at all times, the power output of the generators within the electric power system and capacity and Energy purchased from entities outside the electric power system, with the load within the electric power system;

(ii) maintain scheduled interchange with other interconnected systems, within the limits of Accepted Electric Industry Practice;

(iii) maintain the frequency of the electric power system within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the NPCC and NERC; and

(iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

"**NEPOOL Filed Documents**" shall mean the Tariff, Restated NEPOOL Agreement, and NEPOOL Market Rules.

"**NEPOOL Manuals**" shall mean the NEPOOL operating procedures and other materials that are approved by NEPOOL pursuant to the Restated NEPOOL Agreement.

"**NERC Interchange Distribution Calculator**" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of Energy, over specific transmission interfaces, from Energy transactions.

"Net Commitment Period Compensation" or **"NCPC"** is a payment designed to compensate Resources that are responding to economic dispatch orders when the aggregate revenues from Energy and ancillary services over the Scheduled Dispatch Period fail to equal or exceed the cost of supply as determined from the Resource's Bids.

"Network Transmission Service" as defined in the Tariff is Regional Network Service, which may be used with respect to Network Resources or Network Load not physically interconnected with the NEPOOL Transmission System.

"No-Load Fee" is the amount, in dollars per hour, for a generating unit that must be paid to Participants with Energy Entitlements in the unit for being scheduled in the NEPOOL Market, in addition to the Start-Up Fee and price offered to supply

Energy, for each hour that the generating unit is scheduled in the NEPOOL Market.

"Normal Maximum Generation" shall mean the highest output level of a generating Resource under normal operating conditions.

"Normal Minimum Generation" shall mean the lowest output level of a generating Resource under normal operating conditions.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new Resource, and other data and information necessary to schedule and dispatch generation Resources for the provision of Energy and other services and the maintenance of the reliability and security of the transmission system in the NEPOOL Control Area, and specified for submission to the NEPOOL Market for such purposes by the ISO.

"Operating Day" shall mean the calendar day period beginning at midnight for which transactions on the NEPOOL Market are scheduled.

"Operating Reserve" as defined in Section 1.119 of the Agreement is any or a combination of 10-Minute Spinning Reserve, 10-Minute Non-Spinning Reserve, and 30-Minute Operating Reserve, as the context requires.

"Participant" is an eligible Entity (or group of Entities which has elected to be treated as a single Participant pursuant to Section 4.1 of the Restated NEPOOL Agreement) which is a signatory to the Agreement and has become a Participant in accordance with Section 3.1 of the Restated NEPOOL Agreement until such time as such Entity's status as a Participant terminates pursuant to Section 21.2 of the Restated NEPOOL Agreement.

"Point(s) of Delivery" as defined in the Tariff are Point(s) where capacity and/or energy transmitted by the Participants will be made available to the Receiving Party under the Tariff. Until the CMS/MSS Effective Date, but not thereafter, the Point of Delivery may be designated as the NEPOOL power exchange. The Point(s) of Delivery shall be specified in the Service Agreement, if applicable, for Long-Term Firm Point-to-Point Transmission Service.

"Point(s) of Receipt" as defined in the Tariff are Point(s) of interconnection where capacity and/or energy to be transmitted by the Participants will be made available to NEPOOL by the Delivering Party under the Tariff. Until the CMS/MSS Effective Date, but not thereafter, the Point of Receipt may be designated as the NEPOOL power exchange in circumstances where the System

Operator does not require greater specificity. The Point(s) of Receipt shall be specified in the Service Agreement, if applicable, for Long-Term Firm Point-To-Point Transmission Service.

"Point-To-Point Transmission Service" is the transmission of capacity and/or Energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the Tariff. NEPOOL Point-to-Point Transmission Service includes both Internal Point-to-Point Service and Through or Out Service.

"**Pool-Scheduled Resources**" has the meaning specified in Section 1.10.2.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

"Real-Time Adjusted Generation Obligation" is defined in Section 3.2.1(b)(iv).

"Real-Time Adjusted Generation Obligation Deviation" is defined in Section 3.2.1(c)(iv).

"Real-Time Adjusted Load Obligation" is defined in Section 3.2.1(b)(iii).

"Real-Time Congestion Revenue" is defined in Section 3.2.1(f).

"Real-Time Energy Market" shall mean the purchase or sale of Energy, payment of Congestion Charges, and payments for Marginal Losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day.

"Real-Time Energy Market Deviation Charge/Credit" is defined in Section 3.2.1(e).

"Real-Time Generation Obligation" is defined in Section 3.2.1(b)(ii).

"Real-Time Generation Obligation Deviation" is defined in Section 3.2.1(c)(ii).

"Real-Time Load Obligation" is defined in Section 3.2.1(b)(i).

"Real-Time Locational Adjusted Net Interchange" is defined in Section 3.2.1(b)(v).

"Real-Time Locational Adjusted Net Interchange Deviation" is defined in Section 3.2.1(c)(v).

"Real-Time Load Obligation Deviation" is defined in Section 3.2.1(c)(i).

"Real-Time Marginal Loss Revenue" is defined in Section 3.2.1(i).

"Real-Time Marginal Loss Revenue Charges or Credits" is defined in Section 3.2.1(j).

"Real-Time Prices" shall mean the Locational Marginal Prices resulting from the ISO's dispatch of the NEPOOL Market in the Operating Day.

"Regulation" shall mean the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the NEPOOL Manuals and ISO Administrative Procedures.

"Reliability Region" shall mean, as of March 31, 2000, any one of the regions identified in Attachment C to the Agreement. Subsequent to March 31, 2000, the System Operator, in a filing with the Commission and following consultation with the NEPOOL Reliability Committee, may reconfigure Reliability Regions and add or subtract Reliability Regions as necessary over time to reflect changes to the grid or changes in patterns of usage and intra-zonal Congestion. Reliability Regions reflect the operating characteristics of, and the major transmission constraints on, the NEPOOL Transmission System.

"Resource" means a generating unit, a Dispatchable Load, or a Supply Offer to supply service from another Control Area at an External Node.

"Spot Market Energy" shall mean Energy bought or sold by Participants through the NEPOOL Market at Locational Marginal Prices determined as specified in Section 2 of this Document.

"Self-Schedule" is the action of a Participant in scheduling its Resource, in accordance with applicable Market Rules, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the System Operator to provide the service.

"Seller" shall mean a Participant selling into the NEPOOL Market or a Transmission Customer, as the context requires.

"Start-Up Fee" is the amount, in dollars, that must be paid for a generating unit to Participants with Energy Entitlements in the unit each time the unit is scheduled in the NEPOOL Market to start up.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Document.

"Transmission Congestion Credit" shall mean the allocated share of total Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Document.

"Transmission Congestion Revenue" is defined in Section 3.2.1(f).

"Transmission Customer" as defined in Section 1.171 of the Agreement is any Eligible Customer that (i) is a Participant which is not required to sign a Service Agreement with respect to a service to be furnished to it in accordance with Section 48 of the Tariff or (ii) executes, on its own behalf or through its Designated Agent, a Service Agreement, or (iii) requests in writing, on its own behalf or through its Designated Agent, that NEPOOL file with the Commission a proposed unexecuted Service Agreement in order that the Eligible Customer may receive transmission service under the Tariff.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an emergency or threatened emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the NEPOOL Manuals and ISO Administrative Procedures. A removal from service of a transmission facility at the request of the ISO to improve transmission capability shall not constitute a Transmission Forced Outage.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by the ISO as the security coordinator responsible for maintaining transmission security for the NEPOOL Control Area.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in the NEPOOL Manuals and ISO Administrative Procedures.

1.3.3 Load References.

References to "load" in any particular section or subsection in this Document shall be interpreted in the context of that section or subsection. There is no intent that "load" necessarily be determined in the same way for all sections or subsections. The determination of load for one or more sections or subsections may reflect adjustments, as appropriate, for Bilateral Transactions and/or Self-Supply.

1.4 [Reserved.]

1.5 [Reserved.]

1.6 [Reserved.]

1.6.1 [Reserved.]

1.6.2 [Reserved.]

1.6.3 [Reserved.]

1.6.4 NEPOOL Manuals and ISO Administrative Procedures.

The ISO shall prepare, maintain and update the NEPOOL Manuals and ISO Administrative Procedures consistent with the NEPOOL Filed Documents. The NEPOOL Manuals and ISO Administrative Procedures shall be available for inspection by the Participants, regulatory authorities with jurisdiction over the ISO or any Participant, and the public.

1.7 General.

1.7.1 [Reserved.]

1.7.2 [Reserved.]

1.7.3 Agents.

A Participant may participate in the NEPOOL Market through an agent, provided that such Participant informs the ISO in advance in writing of the appointment of such agent. A Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the NEPOOL Market, and shall ensure that any such agent complies with the requirements of the NEPOOL Manuals and ISO Administrative Procedures and the NEPOOL Filed Documents.

1.7.4 [Reserved.]

1.7.5 [Reserved.]

1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule day-ahead and dispatch in real-time generation economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Participants, continuing until sufficient generation is dispatched to serve the NEPOOL Market Energy purchase requirements under normal system conditions of the Participants, as well as the requirements of the NEPOOL Control Area for ancillary services provided by such generation, in accordance with the NEPOOL Filed Documents. Scheduling and dispatch shall be conducted in accordance with the NEPOOL Filed Documents.

(b) The ISO shall undertake, together with NEPOOL, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the NEPOOL Market, and any relevant procedures of another Control Area, or any tariff (including the Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

1.7.7 Energy Pricing.

The price paid for Energy bought and sold in the NEPOOL Market will reflect the hourly Locational Marginal Price at each load and generation Location, determined by the ISO in accordance with the NEPOOL Filed Documents. Congestion Charges, which shall be determined by differences in the Congestion Component of Locational Marginal Prices (Congestion Cost) in an hour caused by transmission constraints, shall be calculated and collected, and the revenues therefrom shall be disbursed, by the ISO in accordance with this Document.

1.7.8 [Reserved.]

1.7.9 Delivery to an External Buyer.

A purchase of Spot Market Energy by an External Buyer shall be delivered to a Location or Locations at the border of the NEPOOL Control Area identified by the External Buyer from Locations specified by the ISO, or to load in the Control Area that is not served by Regional Network Service, using Point-to-Point Transmission Service paid for by the External Buyer. Further delivery of such Energy shall be the responsibility of the External Buyer.

1.7.10 Other Transactions.

(a) Participants may enter into Bilateral Transactions for the purchase or sale of Energy or other products to or from each other or any other entity, subject to the obligations of Participants to make ICAP Resources available for dispatch by the ISO. Bilateral arrangements that contemplate the physical transfer of Energy to or from a Participant shall be reported to and coordinated with the ISO in accordance with this Document.

(b) [Reserved.]

(c) To the extent the ISO dispatches a Participant's generation Resources, such Participant may elect to net the output of such Resources against its hourly load.

1.7.11 [Reserved.]

1.7.12 [Reserved.]

1.7.13 [Reserved.]

1.7.14 [Reserved.]

1.7.15 [Reserved.]

1.7.16 [Reserved.]

1.7.17 Operating Reserves.

The ISO shall schedule to the Operating Reserve and load-following objectives of the NEPOOL Control Area and the NEPOOL Market in scheduling Resources pursuant to this Document. A table of Operating Reserve objectives is calculated seasonally for various peak load levels and is published in the NEPOOL Manuals and ISO Administrative Procedures. Reserve levels are probabilistically determined based on the season's historical load forecasting error and expected generation mix (including typical planned and forced/unplanned outages).

1.7.18 Regulation.

(a) Regulation shall be supplied from generators located within the metered electrical boundaries of the NEPOOL Control Area. Participants offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the NEPOOL Manuals and ISO Administrative Procedures.

(b) The ISO shall obtain and maintain an amount of Regulation equal to the NEPOOL Control Area Regulation objective as specified in the NEPOOL Manuals and ISO Administrative Procedures.

(c) The Regulation range of a unit shall be at least twice the amount of Regulation assigned and no less than the minimum specified in the NEPOOL Manuals and ISO Administrative Procedures.

(d) A unit capable of automatic Energy dispatch that is also providing Regulation shall have its Energy dispatch range reduced by twice the amount of the Regulation provided. Subject to appropriate adjustments made for fast-response units as further described in the NEPOOL Manuals and ISO Administrative Procedures, the amount of Regulation provided by a unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation Energy limits of that unit, in that the amount of Regulation shall be added to the unit's Normal Minimum Generation Energy limit, and subtracted from its Normal Maximum Generation Energy limit.

(e) Qualified Regulation must satisfy the verification tests described in the NEPOOL Manuals and ISO Administrative Procedures.

1.7.19 Ramping.

A generator dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the ISO for that generator.

1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Participants selling from Resources within the NEPOOL Control Area shall: report to the ISO sources of Energy available for operation; supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO bilateral sales transactions to buyers not within the NEPOOL Control Area; confirm to the ISO bilateral sales to Participants within the NEPOOL Control Area; respond to the ISO's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment is operated with control equipment functioning as specified in the NEPOOL Manuals and ISO Administrative Procedures.

(c) Participants selling from Resources outside the NEPOOL Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of Energy available, hours of availability and prices of Energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Participant's Control Area.

(d) Participants that serve load shall: respond or ensure a response to ISO directives for load management steps; report to the ISO the ICAP Resources they have provided to satisfy their capacity obligations that are available for pool operation; report to the ISO all bilateral purchase transactions; and respond or ensure a response to other ISO directives such as those required during emergency operation.

(e) A Participant shall: provide to the ISO requests to purchase specified amounts of Energy for each hour of the Operating Day during which it intends to purchase from the NEPOOL Market, along with Dispatch Rate levels above which it does not desire to purchase; and respond to other ISO directives such as those required during emergency operation.

1.8 [Reserved.]

1.9 Prescheduling.

1.9.1 [Reserved.]

1.9.2 [Reserved.]

1.9.3 [Reserved.]

1.9.4 [Reserved.]

1.9.5 [Reserved.]

1.9.6 [Reserved.]

1.9.7 Participant Responsibilities.

Participants authorized and intending to request market-based Start-Up and No-Load Fees in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline specified in the NEPOOL Manuals and ISO Administrative Procedures and shall remain in effect without change throughout each such period for which a specification was submitted. The ISO shall reject any request for Start-Up and No-Load fees in a Participant's Offer Data that does not conform to the Participant's specification on file with the ISO.

1.9.8 [Reserved.]

1.10 Scheduling.

1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Participants to purchase and sell Energy through the NEPOOL Market at Day-Ahead Prices and enable Transmission Customers to reserve transmission service with Congestion Charges based on locational differences in the Congestion Component of Day-Ahead Prices. Participants whose purchases and sales and Transmission Customers whose transmission uses are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell Energy, or pay Congestion Charges and payments for Marginal Losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market, Participants that deviate from the amounts of Energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell Energy, or pay Congestion Charges and payments for Losses, for the amount of the deviations at the applicable Real-Time Prices or price differences, unless otherwise specified by this Document.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Participants and system constraints, a plan to serve the hourly Energy and reserve requirements of the NEPOOL Control Area in the least costly manner, subject to maintaining the reliability of the NEPOOL Control Area. If the ISO's forecast for the next seven days projects a likelihood of emergency conditions, the ISO may commit, for all or part of such seven day period, to the use of generation Resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such emergency, in accordance with the Participants' offers for such units for such periods and the specifications in the NEPOOL Manuals and ISO Administrative Procedures.

1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Document.

(a) Each Participant may submit to the ISO specifications of the amount and location of its customer loads and/or Energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the NEPOOL Manuals and ISO Administrative Procedures. Each Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Participant to meet its load; and (iii) the Dispatch Rate at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Participant's intent not to reduce output.

(b) [Reserved.]

(c) All Participants shall submit to the ISO schedules for any Bilateral Transactions involving use of generation or NEPOOL Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Participant that elects to include a Bilateral Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the NEPOOL Manuals and ISO Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Charges. The foregoing price specification shall apply to the price difference between the Congestion Components of the Locational Marginal Prices (Congestion Cost) for specified Bilateral Transaction source and sink points in the day-ahead scheduling process only. Any Participant that elects not to include its Bilateral Transaction in the Day-Ahead Energy Market shall inform the ISO if the parties to the transaction are not willing to incur Congestion Charges in the Real-Time Energy Market in order to complete any such scheduled Bilateral Transaction. Scheduling of Bilateral Transactions shall be conducted in accordance with the specifications in the NEPOOL Manuals and ISO Administrative Procedures and the following requirements:

(i) Participants shall submit schedules for all bilateral purchases for delivery within the NEPOOL Control Area from Resources outside the NEPOOL Control Area;

(ii) Participants shall submit schedules for bilateral sales to entities outside the NEPOOL Control Area from Resources within the NEPOOL Control Area; and

(iii) Participants that submit a schedule for a Bilateral Transaction must ensure the other party submits a confirmation.

(d) Participants wishing to sell into the Day-Ahead Energy Market, from either internal or external Resources, shall submit offers for the supply of Energy (including Energy from hydropower units), Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the ISO in the form specified by the ISO and shall contain the information specified in the ISO's Offer Data specification, as applicable. Participants owning or controlling the output of an ICAP Resource that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such ICAP Resource, including any portion that is Self-Scheduled by the Participant claiming the Resource as an ICAP Resource. The submission of offers for Resource increments that are not ICAP Resources shall be optional, but any such offers must contain the information specified in the ISO's Offer Data specification, as applicable. Energy offered from generation Resources that are not ICAP Resources shall not be supplied from Resources that are included in or otherwise committed to supply the Operating Reserves of another Control Area. The foregoing offers:

(i) Shall specify the generation 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 Participant to the ISO;

(iii) If based on Energy from a specific generating unit, may specify Start-Up and No-Load Fees equal to the specification of such fees for such unit on file with the ISO;

(iv) Shall set forth any special conditions upon which the Participant proposes to supply a Resource increment, including any curtailment rate specified in a bilateral contract for the output of the Resource, or any Cancellation Fees;

(v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Document, with a second schedule applicable if accepted after the foregoing deadline;

(vi) Shall constitute an offer to submit the Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted; and

(vii) Shall be final as to the price or prices at which the Participant proposes to supply Energy or other services to the NEPOOL

Market, such price or prices being guaranteed by the Participant for the period extending through the end of the following Operating Day.

(e) A Participant that wishes to make a Resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatts of Regulation being offered, the price of the offer in dollars per MWh, and such other information specified by the ISO as may be necessary to evaluate the offer and the Resource's Lost Opportunity Costs. Qualified Regulation capability must satisfy the verification tests specified in the NEPOOL Manuals and ISO Administrative Procedures.

(f) Each Participant owning or controlling the output of an ICAP Resource shall submit a forecast of the availability of each such ICAP Resource for the next seven days. A Participant (i) may submit a non-binding forecast of the price at which it expects to offer a generation Resource increment to the ISO over the next seven days, and (ii) shall submit a binding offer for Energy, along with Start-Up and No-Load Fees, if any, for the next seven days or part thereof, for any ICAP Resource with a minimum notification or start-up requirement greater than 24 hours.

(g) Each offer by a Participant of an ICAP Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The ISO shall post on the internet the total hourly loads scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the combined hourly load of the Participants for the next four days, and its peak load forecasts for an additional three days.

(i) All Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such bids must comply with the requirements set forth in the NEPOOL Manuals and ISO Administrative Procedures and must specify amount, location and price, if any, at which the Participant desires to purchase or sell Energy in the Day-Ahead Energy Market.

1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Participants submitted offers to sell Energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide Energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for Energy and related services, Start-Up, No-Load and Cancellation Fees, and the specified operating characteristics, offered by Participants to the ISO by the offer deadline specified in Section 1.10.1A.

(b) Any portion of a Resource that is scheduled by a Participant to support a bilateral sale, or that is Self-Scheduled by a Participant, shall not be selected by the ISO as a Pool-Scheduled Resource except, and only in the case of an ICAP Resource, in an emergency.

(c) Participants offering Energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for Energy or related services, or for Start-Up and No-Load Fees, from the ISO on behalf of the Buyers in accordance with Section 3 of this Document. Alternatively, the Seller shall receive, in lieu of Start-Up and No-Load Fees, its actual costs incurred, if any, up to a cap of the Resource's start-up cost, if the ISO cancels its selection of the Resource as a Pool-Scheduled Resource and so notifies the Seller before the Resource is synchronized ("Cancellation Fee").

(e) Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the NEPOOL Control Area for Operating Reserves.

1.10.3 Self-Scheduled Resources.

Self-Scheduled Resources shall be governed by the following principles and procedures.

(a) [Reserved.]

(b) The offered prices of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.

(c) Participants shall make available their Self-Scheduled Resources to the ISO for coordinated operation to supply the needs of the NEPOOL Control Area for Operating Reserves.

(d) A Participant Self-Scheduling a Resource in the Day-Ahead Energy Market that does not deliver the Energy in the Real-Time Energy Market, shall buy the Energy not delivered with Energy purchased from the Real-Time Energy Market and shall pay for such Energy at the applicable Real-Time Price.

1.10.4 ICAP Resources.

(a) An ICAP Resource selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO. An ICAP Resource that does not deliver Energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such Energy not delivered. A Participant offering such ICAP Resource in the Day-Ahead Energy Market shall buy the Energy not delivered with Energy purchased from the Real-Time Energy Market and shall pay for such Energy at the applicable Real-Time Price.

(b) Energy from an ICAP Resource that has not been scheduled in the Day-Ahead Energy Market may be sold on a bilateral basis by the Participant, may be Self-Scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Document. An ICAP Resource that has not been scheduled in the Day-Ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the ISO for scheduling and dispatch during the Operating Day if the ISO declares a Maximum Generation Emergency. Any such Resource so scheduled and dispatched shall receive the applicable Real-Time Price for Energy delivered.

(c) An ICAP Resource that has been Self-Scheduled shall not receive payments or credits for Start-Up or No-Load Fees.

1.10.5 External Resources.

(a) External Resources may submit offers to the NEPOOL Market, in accordance with the Day-Ahead and Real-Time scheduling processes specified above. An External Resource selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO, and except as specified in 1.10.5(b) below shall be compensated on the same basis as other Pool-Scheduled Resources. Participants shall offer External Resources to the NEPOOL Market on either a Resource-specific or an aggregated Resource basis. A Participant whose Pool-Scheduled Resource does not deliver the Energy scheduled in the Day-Ahead Energy Market shall replace such Energy not delivered as scheduled in the Day-Ahead Energy Market with Energy from the NEPOOL Real-Time Energy Market and shall pay for such Energy at the applicable Real-Time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the ISO: (i) Energy prices; (ii) hours of Energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the ISO, sufficient information, as specified in the NEPOOL Manuals and ISO Administrative Procedures, to enable the ISO to model the flow into the NEPOOL Control Area of any Energy from the External Resources scheduled in accordance with the Offer Data. If a Participant submits more than one offer on an aggregated Resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.

(c) Offers for External Resources on a Resource-specific basis shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Buyers.

(a) Deliveries on behalf of an External Buyer shall be delivered on a block loaded basis to the Location or Locations at the border of the NEPOOL Control Area, or in the NEPOOL Control Area with respect to an External Buyer’s load within the NEPOOL Control Area not served by Regional Network Service, at which the Energy is delivered to or for the External Buyer. Deliveries to External Buyers shall be charged or credited at either the Day-Ahead Prices or Real-Time Prices, whichever is applicable, for Energy at the foregoing Location or Locations.

(b) An External Buyer’s hourly schedules for Energy purchased from the NEPOOL Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the NEPOOL Control Area and the Control Area to which, whether as an intermediate or final point of delivery, the purchased Energy will initially be delivered.

(c) The ISO shall curtail deliveries to an External Buyer from a NEPOOL ICAP Resource if necessary to maintain appropriate reserve levels for the NEPOOL Control Area as defined in the NEPOOL Manuals and ISO Administrative Procedures, or to avoid shedding load in the NEPOOL Control Area.

1.10.6A [Reserved.]

1.10.7 Bilateral Transactions.

Bilateral Transactions as to which the parties have notified the ISO by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-Ahead Energy Market and that they are not willing to incur Congestion Charges in the Real-Time Energy Market shall be curtailed by the ISO as necessary to reduce or alleviate transmission congestion. Bilateral Transactions that were not included in the Day-Ahead Energy Market and that are willing to incur Congestion Charges and Bilateral Transactions that were accepted in the Day-Ahead Energy Market shall continue to be implemented during periods of Congestion, except as may be necessary to respond to emergencies.

1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for Energy, Operating Reserves, and other ancillary services of the Participants, including the reliability requirements of the NEPOOL Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of NEPOOL Market and NEPOOL Control Area Energy requirements, giving due consideration to the Energy requirement forecasts and purchase requests submitted by Participants; (ii) the offers submitted by Participants; (iii) the availability of limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the objectives of the NEPOOL Control Area for Operating Reserves, as specified in the NEPOOL Manuals and ISO Administrative Procedures; (vi) the requirements of the NEPOOL Control Area for Regulation and other ancillary services, as specified in the NEPOOL Manuals and ISO Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the NEPOOL

Manuals and ISO Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule. The ISO shall report the planned schedule for a hydropower Resource to the operator of that Resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not later than 4:00 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the NEPOOL Manuals and ISO Administrative Procedures, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Participants of their scheduled injections and withdrawals.

(c) Following posting of the information specified in Section 1.10.8(b), the ISO shall revise its schedule of generation Resources to reflect updated projections of load, conditions affecting electric system operations in the NEPOOL Control Area, the availability of and constraints on limited Energy and other Resources, transmission constraints, and other relevant factors. The ISO shall post on the NEPOOL web site at times specified in the NEPOOL Manuals and ISO Administrative Procedures a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between Reliability Regions of the NEPOOL Control Area expected to result from such transmission congestion.

(d) Participants shall pay and be paid for the quantities of Energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Participants may submit revisions to generation offer data for any generation Resource that was not selected as a Pool-Scheduled Resource in the Day-Ahead Energy Market. Adjustments to Day-Ahead Energy Markets shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of Energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) A Participant may adjust the schedule of a Resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the ISO is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect (or such shorter period, up to 20 minutes prior to the hour, when the ISO has notified the Participants that it has the necessary hardware, software, and procedures in place to implement the shorter notice period), as follows:

(i) A Participant may Self-Schedule any of its Resources consistent with the NEPOOL Manuals and ISO Administrative Procedures;

(ii) A Participant may request the scheduling of a non-firm Bilateral Transaction;

(iii) A Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

(iv) A Participant may remove from service a Resource increment, including a hydropower Resource, that it had previously designated as Self-Scheduled, provided that the ISO shall have the option to schedule Energy from any such Resource increment that is an ICAP Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Fee.

(c) With respect to the portion of a Pool-Scheduled Resource that is included in the Day-Ahead Energy Market, a Participant may not change or otherwise modify its offer to sell Energy.

(d) An External Buyer may refuse delivery of some or all of the Energy it requested to purchase in the Day-Ahead Energy Market by notifying the ISO of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect (or such shorter period, up to 20 minutes prior to the hour, when the ISO has notified the Participants that it has the necessary hardware, software, and procedures in place to implement the shorter notice period), but any such adjustment shall not affect the obligation of the External Buyer to pay for Energy scheduled on its behalf in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the ISO shall provide Participants and parties to Bilateral Transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

1.11.1 Resource Output.

The ISO shall have the authority to direct any Participant to adjust the output of any Pool-Scheduled Resource increment within the operating characteristics specified in the Participant's offer. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources, subject to an obligation to pay any applicable Start-Up, No-Load or Cancellation Fees. The ISO shall adjust the output of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the Energy, reserves, and other services required by the Participants and the operation of the NEPOOL Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the NEPOOL Control Area; and (c) to minimize unscheduled interchange not frequency related between the NEPOOL Control Area and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the NEPOOL Control Area in accordance with the NEPOOL Manuals and ISO Administrative Procedures, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The ISO shall implement the dispatch of Energy from Pool-Scheduled Resources with limited Energy by direct request. In implementing mandatory or economic use of limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the NEPOOL Control Area and the availability of other Resources to the ISO.

(b) The ISO shall 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, in accordance with the NEPOOL Manuals and ISO Administrative Procedures. Each Participant shall ensure that the entity controlling a pool-dispatched Resource offered or made available by that Participant complies with the Energy dispatch signals and instructions transmitted by the ISO.

1.11.3A Maximum Generation Emergency.

If the ISO declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the NEPOOL Control Area from ICAP Resources may be interrupted in order to serve load in the NEPOOL Control Area.

1.11.4 Regulation.

(a) A Participant may satisfy its Regulation obligation from its own Resources capable of performing Regulation service, by contractual arrangements with other Participants able to provide Regulation service, or by purchases from the NEPOOL Market at the rates set forth in Section 3.2.2.

(b) The ISO shall obtain Regulation service from the least-cost alternatives available from either Pool-Scheduled or Self-Scheduled Resources as needed to meet NEPOOL Control Area requirements not otherwise satisfied by the Participants. Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each Resource's regulation offer and the estimated Lost Opportunity Cost of the Resource providing Regulation and in accordance with the ISO's obligation to minimize the total cost of Energy, Operating Reserves, Regulation, and other ancillary services. Estimated Lost Opportunity Costs shall be determined by the ISO on the basis of the expected value of the Energy sales that would be foregone or uneconomic Energy that would be produced by the Resource in order to provide Regulation, in accordance with procedures specified in the NEPOOL Manuals and ISO Administrative Procedures. If the ISO is not able to distinguish Resources offering Regulation on the basis of their Regulation offers and estimated Lost Opportunity Costs, Resources shall be selected on the basis of the quality of Regulation provided by the Resource as determined by tests administered by the ISO.

(c) The ISO shall dispatch Resources for Regulation by sending Regulation signals and instructions to Resources from which Participants, in accordance with the NEPOOL Manuals and ISO Administrative Procedures, have offered Regulation service. Participants shall comply with Regulation dispatch signals and instructions transmitted by the ISO and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over Energy dispatch signals and instructions. Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources supplying load in the NEPOOL Control Area as close to desired output levels as practical, consistent with Good Utility Practice.

2. CALCULATION OF LOCATIONAL MARGINAL PRICES

2.1 Introduction.

The ISO shall calculate the price of Energy at the applicable Locations in the NEPOOL Control Area and between the NEPOOL Control Area and adjacent Control Areas on the basis of Locational Marginal Prices as determined in accordance with Section 14A.5 of the Agreement and this Section 2. Locational Marginal Prices shall be calculated on a day-ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market.

2.2 General.

The ISO shall determine the least cost security-constrained dispatch, which is the least costly means of serving load at different Locations in the NEPOOL Control Area based on operating conditions existing on the power grid and on the prices at which Participants have offered to supply Energy in the NEPOOL Market. Locational Marginal Prices for the applicable Locations will be calculated based on the economic dispatch and the prices of Energy offers. Except as further provided in Section 2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions on the power grid in the NEPOOL Control Area, the ISO shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying Energy to the NEPOOL Control Area, loads at busses in the

NEPOOL Control Area, transmission losses, penalty factors, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between NEPOOL and other Control Areas, will be obtained from the ISO's dispatchers.

(b) Using the prices at which Participants offer Energy to the NEPOOL Market, the ISO shall determine the offers of Energy that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every offer of Energy by a Participant from a Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Locational Marginal Prices.

(c) Based on the system conditions on the NEPOOL power grid, determined as described in (a), and the eligible Energy offers, determined as described in (b), the ISO shall determine the least costly means of obtaining Energy to serve the next increment of load at each Location in the NEPOOL Control Area, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the NEPOOL Control Area by using the most recent power flow solution produced by the State Estimator, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Locations for which real-time information is unavailable. The current version of the State Estimator includes over **[number to be added in compliance filing prior to effective date]** busses in the NEPOOL Control Area, as well as interface busses with adjacent Control Areas. The ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the NEPOOL Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External transactions between NEPOOL and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the ISO's dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-Time Prices.

(a) During the Operating Day, Real-Time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of Energy in the Real-Time Energy Market and of Congestion Charges under the Tariff not covered by the Day-Ahead Energy Market.

(b) To determine the Energy offers submitted to the NEPOOL Market that shall be used during the Operating Day to calculate the Real-Time Prices, the ISO shall determine which Resources are following its economic dispatch instructions. A Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable price bid by a Participant for Energy from the Resource is less than or equal to the Dispatch Rate for the area of the NEPOOL Control Area in which the Resource is located; or

(ii) the Resource is specifically requested to operate by the ISO's dispatcher.

(c) In determining whether a Resource satisfies the condition described in (b), the ISO will determine the bid price associated with an Energy offer by comparing the actual megawatt output of the Resource with the Participant's offer price curve. Because of practical generator response limitations, a Resource whose megawatt output is not ten percent more than the megawatt level specified on the offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the Energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-Time Prices.

2.5 Calculation of Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining Energy to serve the next increment of load at each Location in the NEPOOL Control Area represented in the State Estimator and each interface Location between the NEPOOL Control Area and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the Energy offers that are the basis for the Day-Ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying an incremental linear optimization method to minimize Energy costs, given actual system conditions, a set of Energy offers, and any binding transmission constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Location from each Resource associated with an eligible Energy offer as the sum of: (1) the price at which the Participant has offered to supply an additional increment of Energy from the Resource; (2) the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of the Resource, based on the effect of increased generation from that Resource on transmission line loadings; and (3) the effect of marginal transmission losses caused by the increment of load and generation. The Energy offer or offers that can serve an increment of load at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Location.

(b) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of Real-Time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Prices for that hour.

2.6 Calculation of Day-Ahead Prices.

For the Day-Ahead Energy Market, day-ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained dispatch, model flows and system conditions resulting from the load specifications, offers for Resources, Increment Bids, Decrement Bids, and Bilateral Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market. Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for purchases and sales of Energy and Congestion Charges resulting from the Day-

Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize Energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Location from each Resource associated with an eligible Energy offer as the sum of: (1) the price at which the Participant has offered to supply an additional increment of Energy from the Resource; (2) the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of the Resource, based on the effect of increased generation from that Resource on transmission line loadings; and (3) the effect of marginal transmission losses caused by the increment of load and generation. The Energy offer or offers that can serve an increment of load at a Location at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Location.

2.7 Performance Evaluation.

The ISO shall undertake an evaluation of the foregoing procedures for the determination of Locational Marginal Prices, as well as the procedures for determining and awarding Financial Transmission Rights and associated Congestion Charges and Credits, not less often than every two years, in accordance with the NEPOOL Manuals and ISO Administrative Procedures. To the extent practical, the ISO shall retain all data needed to perform comparisons and other analyses of locational marginal pricing. The ISO shall report the results of its evaluation to the Participants, along with its recommendations, if any, for changes in the procedures.

3. ACCOUNTING AND BILLING

3.1 Introduction.

This Section 3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the NEPOOL Market and for the operation of the NEPOOL Control Area.

3.2 Participants.

3.2.1 Spot Market Energy.

(a) For each Participant for each hour, the ISO will determine a Day-Ahead Energy Market position representing that Participant’s net purchases from or sales to the NEPOOL Day-Ahead Energy Market. To accomplish this, the ISO will perform calculations to determine the following.

(i) **Day-Ahead Load Obligation** - Each Participant shall have for each hour a Day-Ahead Load Obligation for Energy at each Location equal to the megawatt hours of its Decrement Bids accepted by the System Operator in the Day-Ahead Market for Energy at that Location.

(ii) **Day-Ahead Generation Obligation** - Each Participant shall have for each hour a Day-Ahead Generation Obligation for Energy at each Location equal to the megawatt hours of its Generation Offer **and** Increment Bids accepted by the System Operator in the Day-Ahead Market for Energy at that Location.

(iii) **Day-Ahead Adjusted Load Obligation** - Each Participant shall have for each hour a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by the Day-Ahead internal Bilateral Transactions at that Location.

(iv) **Day-Ahead Adjusted Generation Obligation** - Each Participant shall have for each hour a Day-Ahead Adjusted Generation Obligation at each Location equal to the Day-Ahead Generation Obligation adjusted by the Day-Ahead internal Bilateral Transactions at that Location.

(v) **Day-Ahead Locational Adjusted Net Interchange –** Each Participant shall have for each hour a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Adjusted Generation Obligation at that Location.

(b) For each Participant for each hour, the ISO will determine a Real-Time Energy Market position. To accomplish this, the ISO will perform calculations to determine the following.

(i) **Real-Time Load Obligation** - Each Participant shall have for each hour a Real-Time Load Obligation for Energy at each Location equal to the megawatt hours of load at that Location.

(ii) **Real-Time Generation Obligation -** Each Participant shall have for each hour a Real-Time Generation Obligation for Energy at each Location. The Real-Time Generation Obligation shall equal the megawatt hours of Energy provided by Resources at that Location.

(iii) **Real-Time Adjusted Load Obligation** - Each Participant shall have for each hour a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by the internal Real-Time Bilateral Transactions at that Location.

(iv) **Real-Time Adjusted Generation Obligation** - Each Participant shall have for each hour a Real-Time Adjusted Generation Obligation at each Location equal to the Real-Time Generation Obligation adjusted by the internal Real-Time Bilateral Transactions at that Location.

(v) **Real-Time Locational Adjusted Net Interchange** – Each Participant shall have for each hour a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Adjusted Generation Obligation at that Location.

(c) For each Participant for each hour, the ISO will determine the difference between the Day-Ahead Energy Market position (Section 3.2.1 (a)) and the Real-Time Energy Market position (Section 3.2.1(b)) representing that Participant's net purchases from or sales to the NEPOOL Real-Time Energy Market. To accomplish this, the ISO will perform calculations to determine the following.

(i) **Real-Time Load Obligation Deviation –** Each Participant shall have for each hour a Real-Time Load Obligation Deviation at each Location equal to the difference in megawatt hours between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation –** Each Participant shall have for each hour a Real-Time Generation Obligation Deviation at each Location equal to the difference in megawatt hours between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation –** Each Participant shall have for each hour a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in megawatt hours between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Adjusted Generation Obligation Deviation –** Each Participant shall have for each hour a Real-Time Adjusted Generation Obligation Deviation at each Location equal to the difference in megawatt hours between the Real-Time Adjusted Generation Obligation and the Day-Ahead Adjusted Generation Obligation.

(v) **Real-Time Locational Adjusted Net Interchange Deviation –** Each Participant shall have for each hour a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in megawatt hours between the Real-Time Locational Adjusted Net Interchange and the Day-Ahead Locational Adjusted Net Interchange.

(d) For each Participant for each hour, the ISO will determine a Day-Ahead Energy Market monetary position representing a charge or credit for its net purchases from or sales to the NEPOOL Day-Ahead Energy Market. The **Day-Ahead Energy Market Charge/Credit** shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges times the associated Day-Ahead Locational Marginal Prices.

(e) For each Participant for each hour, the ISO will determine a Real-Time Energy Market monetary position representing a charge or credit to the Participant for its net purchases from or sales to the NEPOOL Real-Time Energy Market. The **Real-Time Energy Market Deviation Charge/Credit** shall be equal to the sum of its Location specific Real-Time Locational Adjusted Net Interchange Deviations times the associated Real-Time Locational Marginal Prices.

(f) For each hour, the ISO will determine the total revenues associated with Transmission Congestion on the NEPOOL transmission system. To accomplish this, the ISO will perform calculations to determine the following. The **Transmission Congestion Revenue** shall be equal to the sum of the Day-Ahead and Real-Time Congestion Revenues. The **Day-Ahead Congestion Revenue** shall equal the net of the Location specific Day-Ahead Adjusted Generation and Load Obligations times the Congestion Component of the associated Day-Ahead Locational Marginal Price summed for all Participants. The **Real-Time Congestion Revenue** shall equal the net of the Location specific Real-Time Adjusted Generation and Load Obligation Deviations times the Congestion Component of the associated Real-Time Locational Marginal Price, summed for all Participants.

(g) For each hour, the ISO will determine the excess or deficiency in Marginal Loss Revenue associated with the Day-Ahead Market. The **Day-Ahead Marginal Loss Revenue** shall be equal to the sum of all Participants' Day-Ahead monetary positions (Section 3.2.1(d)) less Day-Ahead Congestion Revenue (Section 3.2.1(f)).

(h) For each hour for each Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in Marginal Loss Revenue (Section 3.2.1(g)). The **Day-Ahead Marginal Loss Charges and Credits** shall be equal to the Day-Ahead Marginal Loss Revenue times the Participant's pro rata share of the sum of all Participants' Day-Ahead Adjusted Load Obligations.

(i) For each hour, the ISO will determine the excess or deficiency in Marginal Loss Revenue associated with the Real-Time Market. The **Real-Time Marginal Loss Revenue** shall be equal to the sum of all Participants' Real-Time monetary positions (Section 3.2.1(e)) less Real-Time Congestion Revenue (Section 3.2.1(f)).

(j) For each hour for each Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Marginal Loss Revenue (Section 3.2.1(i)). The **Real-Time Marginal Loss Revenue Charges or Credits** shall be equal to the Real-Time Marginal Loss Revenue times the Participant's pro rata share of the sum of all Participants' Real-Time Adjusted Load Obligation Deviations.

3.2.2 Regulation.

(a) Each Participant shall have an hourly Regulation obligation equal to its pro rata share of the NEPOOL Control Area Regulation requirements for the hour, based on the Participant's total load in the NEPOOL Control Area for the hour. A Participant that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the ISO to meet such obligation at the Regulation Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) A Participant supplying Regulation at the direction of the ISO in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation Clearing Price or (ii) the sum of the regulation offer and the unit-specific Lost Opportunity Cost of the Resource supplying the increment of Regulation, as determined by the ISO in accordance with procedures specified in the NEPOOL Manuals and ISO Administrative Procedures.

(c) The Regulation Clearing Price shall be determined by the ISO. The Regulation Clearing Price for each hour shall be equal to the highest sum, for any Resource selected to provide Regulation, of a Resource's Regulation offer plus its estimated unit-specific Lost Opportunity Costs.

(d) In determining the Regulation Clearing Price, the estimated unit-specific Lost Opportunity Costs of a Resource offering to sell Regulation each hour shall be equal to the product of (i) the deviation of the set point of the Resource that is expected to be required in order to provide Regulation from the Resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation Location for the Resource and the offer price for Energy from the Resource (at the megawatt level of the Regulation set point for the Resource) in the NEPOOL Market.

(e) In determining the credit under subsection (b) to a Participant that is selected to provide Regulation and that actively follows the ISO's Regulation signals and instructions, the unit-specific Lost Opportunity Cost of a Resource shall be determined for each hour that the ISO requires a Resource to provide Regulation and shall be equal to the product of (i) the deviation of the Resource's output necessary to follow the ISO's Regulation signals from the Resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation Location for the Resource and the offer price for Energy from the Resource (at the megawatt level of the Regulation set point for the Resource) in the NEPOOL Market.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation Clearing Price in that hour shall be allocated and charged to each Participant that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in megawatt-hours during that hour.

3.2.3 Operating Reserves & Net Commitment Period Compensation.

(a) A Participant's Pool-Scheduled Resources capable of providing Operating Reserve shall be credited as specified below based on the prices offered for the operation of such Resource, provided that the Resource was available for the entire time specified in the Offer Data for such Resource.

(b) The following determination shall be made for each Pool-Scheduled Resource that is scheduled in the Day-Ahead Energy Market: the total offered price for Start-Up and No-Load Fees and Spot Market Energy, determined on the basis of the Resource's scheduled output, shall be compared to the total value of that Resource's Spot Market Energy as determined by the Day-Ahead Energy Market and the Day-Ahead Prices applicable to the relevant generation Location in the Day-Ahead Energy Market. If the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Participant.

(c) Except as otherwise provided in Section 6, the sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) shall be the Net Commitment Period Compensation ("NCPC") in the Day-Ahead Energy Market.

(d) The NCPC in the Day-Ahead Energy Market shall be allocated and charged to each Participant in proportion to the sum of its (i) scheduled load and accepted Decrement Bids in the Day-Ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled Energy sales in the Day-Ahead Energy Market from within the NEPOOL Control Area to load outside the NEPOOL Control Area in megawatt-hours for that Operating Day.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized Pool-Scheduled Resource of each Participant that operates as requested by the ISO and that is not committed solely for the purpose of providing spinning reserves and compensated under (i) below: the total offered price for Start-Up and No-Load Fees and Spot Market Energy, determined on the basis of the lesser of the Resource's (i) hourly output as determined by the State Estimator, or (ii) requested output as determined by the ISO dispatch. The total offered price shall be compared to the total value of that Resource's Energy in the Day-Ahead Energy Market plus any credit or charge for quantity deviations, at the ISO dispatch direction, from the Day-Ahead Energy Market during the Operating Day. If the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) and less any amounts credited for Regulation in excess of the Regulation offer plus the Resource's Lost Opportunity Cost, shall be credited to the Participant.

(f) A Participant's Pool-Scheduled Resource, the output of which is reduced or suspended at the request of the ISO for the purpose of maintaining reliability within the NEPOOL Control Area, shall be credited in an amount equal to (PAG - AG) x LT x (ULMP - UB) where:

PAG equals the actual generation of the unit for the five-minute period preceding the request;

AG equals the actual generation of the unit until the ISO cancels the request to reduce output;

LT equals the length of time that the request to reduce output was effective;

ULMP equals the Locational Marginal Price at the unit's Location;

UB equals the unit bid for that unit whose output is reduced or suspended; and

where ULMP - UB shall not be negative.

(g) The sum of the foregoing credits, plus any Cancellation Fees paid in accordance with Section 1.10.2(d), such Cancellation Fees to be applied to the Operating Day for which the unit was scheduled, less any payments received from another Control Area for Operating Reserves, shall be the NCPC for the Real-Time Energy Market in each Operating Day.

(h) The NCPC for the Real-Time Energy Market for each Operating Day shall be allocated and charged to each Participant in proportion to the sum of the absolute values of its (i) load deviations from the Day-Ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations from the Day-Ahead Energy Market for non-dispatchable generation Resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-Ahead Energy Market for Bilateral Transactions from outside the NEPOOL Control Area for delivery within the NEPOOL Control Area in megawatt-hours during the Operating Day; and (iv) deviations of Energy sales from the Day-Ahead Energy Market from within the NEPOOL Control Area to load outside the NEPOOL Control Area in megawatt-hours during that Operating Day.

(i) At the end of each Operating Day, Participants shall be credited on the basis of their offered prices for synchronized condensing for any hydropower or combustion turbine units operated as synchronous condensers but producing no Energy, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing spinning reserves, at the request of the ISO.

(j) The sum of the foregoing credits as specified in Section 3.2.3(b) shall be the cost of Operating Reserves for synchronized condensing for the Operating Day in the NEPOOL Control Area.

(k) The cost of Operating Reserves for synchronized condensing for each Operating Day shall be allocated and charged to each Participant in proportion to its actual load during that Operating Day.

3.2.4 Transmission Congestion.

Participants shall be charged or credited for Congestion Charges as specified in Section 5 of this Document and the Tariff.

3.2.5 [Reserved.]

3.2.6 Emergency Energy.

(a) Hourly net costs in excess of Real-Time Prices attributable to the purchase of emergency Energy from other Control Areas shall be allocated to Participants who are net buyers from the NEPOOL Real-Time Energy Market (summation of Real-Time Locational Adjusted Net Interchange values for all Locations yields a negative number) during the hour(s) of the purchase.

(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 Participants who are net buyers from the NEPOOL Real-Time Energy Market (summation of Real-Time Locational Adjusted Net Interchange values for all Locations yields a negative number) during the hour(s) of the sale.

(c) The costs associated with hourly Energy purchases from another Control Area in connection with a Minimum Generation Emergency in such other Control Area, shall be allocated to each Participant in proportion to its

Real-Time load in the NEPOOL Control Area during the hour of such purchases.

(d) The revenues associated with hourly Energy sales to other Control Areas in connection with a Minimum Generation Emergency in the NEPOOL Control Area shall be allocated to Participants who are net sellers in the NEPOOL Real-Time Energy Market (summation of Real-Time Locational Adjusted Net Interchange values for all Locations yields a negative number) during the hour(s) of such sales.

3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle for each Participant in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Document, and showing the net amount to be paid or received by the Participant. Billing statements shall provide sufficient detail, as specified in the NEPOOL Manuals and ISO Administrative Procedures, to allow verification of the billing amounts and completion of the Participant's internal accounting.

3.3 [Reserved.]

3.4 Non-Participant Transmission Customers.

3.4.1 Transmission Congestion.

Non-Participant Transmission Customers shall be charged or credited for Congestion Charges as specified in Section 5 of this Document and the Tariff.

3.4.2 Transmission Losses.

Non-Participant Transmission Customers shall be charged or credited in accordance with Schedule 13 of the Tariff for transmission losses in an amount equal to the product of (i) the Transmission Customer's megawatt-hours of deliveries using Point-to-Point Transmission Service, times (ii) the difference between the Marginal Loss Components of the Locational Marginal Prices at the source and the sink.

3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle for each Transmission Customer in accordance with the charges and credits specified in Sections 3.4.1 through 3.4.2 of this Document, and showing the net amount to be paid or received by the Transmission Customer. Billing statements shall provide sufficient detail, as specified in the NEPOOL Manuals and ISO Administrative Procedures, to allow verification of the billing amounts and completion of the Transmission Customer's internal accounting.

3.5 [Reserved.]

3.6 Data Reconciliation.

3.6.1 Data Correction Billing.

The ISO will reconcile Participant data errors and corrections after the correction limit for such data has passed. The correction limit for Participant supplied meter data and for ISO errors in the processing of meter and other Participant data is three calendar months from the date of initial billing of the Operating Day to which the data applied.

3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from assigned meter readers. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the real time dispatch. Data handling errors that impacted unit commitment or the real time dispatch will not be corrected.

3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data at any time prior to the correction limit. No revisions to other Participant data will be accepted after the deadlines for submittal of that data have passed. If the ISO discovers a data error or if a Participant discovers and notifies the ISO of a data error prior to the correction limit, revised hourly data will be used to recalculate Energy, Operating Reserve and Regulation. No settlement recalculations or other adjustments may be made if the correction limit for the Operating Day to which the error applied has passed.

3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the NEPOOL Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the NEPOOL Control Area and the other Control Area to maintain a proper record of inadvertent energy flow.

3.6.5 Meter Correction Data.

(a) Unless otherwise specified in the NEPOOL Manuals and ISO Administrative Procedures, revised meter data shall be submitted to the ISO as soon as it is available and not later than the correction limit.

(b) Unless otherwise specified in the NEPOOL Manuals or the ISO Administrative Procedures, errors on the part of the ISO in the administration of Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the correction limit.

4. [Reserved.]

5. CALCULATION OF TRANSMISSION CONGESTION CHARGES AND CREDITS

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by ISO.

When the transmission system is operating under constrained conditions, the ISO shall calculate Congestion Charges.

5.1.2 General.

The basis for the Congestion Charges shall be the differences in the Congestion Component of the Locational Marginal Prices (Congestion Costs) between Points of Delivery and Points of Receipt, as determined in accordance with Section 2 of this Document.

5.1.3 [Reserved.]

5.1.4 Transmission Customer Calculation.

Except as specified in this subsection, a Congestion Charge shall be assessed for transmission use scheduled in the Day-Ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Congestion Component of the Day-Ahead Locational Marginal Price at the delivery point or NEPOOL Control Area boundary delivery interface and the Congestion Component of the Day-Ahead Locational Marginal Price at the source point or NEPOOL Control Area boundary source interface. Congestion Charges shall be assessed for Real-Time transmission use in excess of the amounts scheduled for each hour in the Day-Ahead Energy Market, calculated as the excess amount multiplied by the difference between the Congestion Component of the Real-Time

Locational Marginal Price at the delivery point or NEPOOL Control Area boundary delivery interface, and the Congestion Component of the Real-Time Locational Marginal Price at the source point or NEPOOL Control Area boundary source interface. A Transmission Customer shall be credited for Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-Ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Congestion Component of the Real-Time Locational Marginal Price at the delivery point or NEPOOL Control Area boundary delivery interface, and the Congestion Component of the Real-Time Locational Marginal Price at the source point or NEPOOL Control Area boundary source interface. Deviations from the Point-to-Point Transmission Service scheduled in the Day-Ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service. Participants and Non-Participants using Point-to-Point Transmission Service for deliveries into, out of or through the NEPOOL Control Area shall be included in the determination of the Congestion Charges.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right ("FTR") shall receive as a Transmission Congestion Credit a proportional share of the total monthly Congestion Charges collected.

(b) If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Bid and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in Locational Marginal Prices in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in Locational Marginal Prices between such delivery and receipt Locations in the Real-Time Energy Market, then the Participant shall not receive any Transmission Congestion Credit, associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the Financial Transmission Rights Auction.

(c) For purposes of Section 5.2.1(b) a Location shall be considered at or near the FTR delivery or receipt Location if seventy-five percent or more of the

Energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the FTRs held at the time of the constrained hour. All FTRs shall be awarded to Eligible FTR bidders (as described in Section 7 herein).

(b) An FTR, or the right to Transmission Congestion Credits attributable to an FTR, may be sold or otherwise transferred by agreement, subject to compliance with Schedule 14 of the Tariff and such procedures as may be established by the ISO for verification of the rights of the purchaser or transferee.

5.2.3 [Reserved.]

5.2.4 Target Allocation to FTR Holders.

A target allocation of Transmission Congestion Credits for each FTR Holder shall be determined for all applicable FTRs. Each FTR shall be multiplied by the Congestion Component of the Day-Ahead Locational Marginal Price differences for the associated receipt and delivery points. This calculation will result in a positive or negative FTR target allocation. All negative target allocations are obligations to pay and are added to Congestion Charges. All positive target allocations will be summed for a Participant for the month and compensated as Transmission Congestion Credits under Section 5.2.5.

5.2.5 Calculation of Transmission Congestion Credits.

(a) The sum of all monthly positive target allocations, as determined in Section 5.2.4 above, shall be compared to Congestion Charges collected for the month (as described above) plus any surplus Congestion Charges from the prior month. If the sum of all monthly positive target allocations is less than the sum of all hourly Congestion Charges for the month plus any surplus Congestion Charges from the prior month, the Transmission Congestion Credit for each FTR Holder shall be equal to its total monthly positive target allocation. All remaining monthly Congestion Charges shall be summed with any surplus from the prior month and carried over into the following month.

(b) If the sum of all the monthly positive target allocations is greater than the Congestion Charges for the month, plus any surplus Congestion Charges from the prior month, each FTR Holder shall be assigned a share of the total Congestion Charges for the month plus any surplus from the prior month in proportion to its total monthly positive target allocations.

5.2.6 Distribution of Excess Congestion Revenue.

If there is any remaining Congestion Charges at year's end, this amount shall be proportionally allocated to any remaining unpaid monthly target allocations in any month of that year, but shall not exceed the amount of each unpaid monthly target allocation. Any remaining surplus Congestion Charges over and above the total of all unpaid monthly target allocation for the year shall be allocated to the entities who paid Congestion Costs in that calendar year.

6. RELIABILITY MUST RUN

6.1 Definition.

RMR Resources are those identified by the ISO as necessary to preserve the reliability of a Reliability Region and scheduled to operate out-of-merit order. RMR Resources provide local voltage or VAR support or meet local Regulation or Operating Reserve requirements.

6.2 Day-Ahead and Real-Time Market.

The ISO will choose what units will provide RMR on a not unduly discriminatory basis. When establishing operating schedules, the ISO will choose (or "flag") which units must be operated for RMR. The ISO will also indicate, in an auditable log, why the unit was so chosen.

6.3 [Reserved.]

6.4 RMR Uplift.

6.4.1 [Reserved.]

6.4.2 [Reserved.]

6.4.3 Calculation of RMR Uplift Payments.

Day-Ahead and Real-Time credits for RMR Resources are determined in accordance with the provisions of paragraphs (a), (b), (c) and (e) in Section 3.2.3, as applied to Pool-Scheduled Resources, but such credits shall not be included in NCPC pursuant to Section 3.2.3 and shall instead be allocated and charged in accordance with Section 6.4.4. The Day-Ahead and Real-Time credits for RMR Resources are subject to market power review and mitigation.

6.4.4 Calculation of RMR Uplift Charges.

The Day-Ahead credits for RMR Resources providing Regulation or Operating Reserve are allocated and charged pro rata to Day-Ahead scheduled load in the affected Reliability Region. Real-Time credits for RMR Resources providing Regulation or Operating Reserve are allocated and charged pro rata to load deviations from the Day-Ahead Energy Market in the affected Reliability Region. Credits for RMR Resources providing local voltage or VAR support are allocated and charged in accordance with the provisions of Schedule 2 of the Tariff.

7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS

7.1 Auctions of Financial Transmission Rights.

Periodic auctions ("FTR Auctions") to allow Eligible FTR Bidders to acquire or FTR Holders to sell FTRs shall be conducted by the ISO in accordance with the provisions of this Section.

7.1.1 Auction Period and Scope of Auctions.

(a) Initially, FTR auctions shall be held on both a semi-annual and monthly basis. The term of the FTRs awarded in the initial two semi-annual auctions shall be six months. In the first semi-annual auction, ten percent of the transfer capability of the NEPOOL Transmission System will be made available to support the sale of FTRs. In the second semi-annual auction, twenty-five percent of the transfer capability of the NEPOOL Transmission System will be made available to support the sale of FTRs. During this initial twelve-month period, following each semi-annual FTR Auction, the remaining transfer capability of the NEPOOL Transmission System will be made available to support the sale of FTRs with a term of one month in the monthly FTR auctions.

(b) Following the initial auctions described above, FTR auctions shall be held on both an annual and monthly basis. Fifty percent of the feasible FTRs that can be made available with a term of one year to five years (in one-year increments for the five calendar years immediately subsequent to the FTR Auction) shall be made available in the annual FTR Auction. After the annual FTR Auction has been conducted, the remaining feasible FTRs, each having a term of one month, shall be made available in the monthly FTR Auctions.

7.1.2 Frequency and Time of FTR Auctions.

(a) Annual (initially semi-annual) auctions: The bid and offer period shall open at the beginning of the first business day of the month preceding the period for which FTRs are being auctioned and shall close at 12:00 midnight (Eastern Prevailing Time) on the fifth business day of the month preceding the period for which FTRs are being auctioned.

(b) Monthly auctions: The bid and offer period shall open at 12:00 midnight (Eastern Prevailing Time) on the fifteenth (15th) business day preceding the month for which FTRs are being auctioned and shall close at 12:00 midnight (Eastern Prevailing Time) on the tenth (10th) business day preceding the month for which FTRs are being auctioned.

7.2 Financial Transmission Rights Characteristics.

7.2.1 Reconfiguration of Financial Transmission Rights.

Using an appropriate linear programming model, the ISO shall reconfigure the FTRs offered or otherwise available for sale in any auction to maximize the value to the bidders of the FTRs sold, provided that any FTRs acquired at auction shall be simultaneously feasible in combination with those FTRs outstanding at the time of the auction and not sold in the auction. The linear programming model shall, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, select the set of simultaneously feasible FTRs with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers.

7.2.2 Specified Locations.

Auction bids for FTRs may specify any combination of receipt and delivery locations represented in the State Estimator model for which the ISO calculates and posts Locational Marginal Prices. Auction bids may specify receipt and delivery points from locations outside of the NEPOOL Control Area to locations inside the NEPOOL Control Area, from locations within the NEPOOL Control Area to locations outside of the NEPOOL Control Area, or to and from locations within the NEPOOL Control Area.

7.2.3 Transmission Congestion Revenues.

FTRs shall entitle holders thereof to credits only for Congestion Charges, and shall not confer a right to credits for payments arising from or relating to transmission congestion made to any entity other than the ISO.

7.3 Auction Procedures.

7.3.1 Role of the ISO.

FTRs auctions shall be conducted by the ISO in accordance with standards and procedures set forth in the NEPOOL Manuals and ISO Administrative Procedures, such standards and procedures to be consistent with the requirements of this Document.

7.3.2 [Reserved.]

7.3.3 [Reserved.]

7.3.4 On-Peak and Off-Peak Periods.

The ISO will conduct separate auctions simultaneously for on-peak and off-peak periods. On-peak FTRs shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the NEPOOL Manuals and ISO Administrative Procedures. Off-peak FTRs shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and holidays as defined in the NEPOOL Manuals and ISO Administrative Procedures. Each bid shall specify whether it is for an on-peak or off-peak period.

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase FTRs shall be submitted during the applicable period set forth in Section 7.1.2, and shall be in the form specified by the ISO in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific FTRs, by megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of FTRs shall constitute an offer to sell a quantity of FTRs equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the FTR. Offers shall be subject to such reasonable standards for the creditworthiness of the offeror or for the posting of security for performance as the ISO shall establish.

(c) Bids to purchase shall specify the megawatt quantity, price per megawatt, and receipt and delivery points of the FTR that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of FTRs shall constitute a bid to purchase a quantity of FTRs equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify as receipt or delivery points any Location for which the ISO calculates and posts Locational Marginal Prices in accordance with Section 2 of this Document and may include FTRs for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such reasonable standards for the creditworthiness of the bidder or for the posting of security for performance as the ISO shall establish.

(d) Bids and offers shall be specified to the nearest megawatt and shall be greater than zero.

7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the ISO will create a base FTRs power flow model that includes all outstanding FTRs that have been approved and confirmed for any portion of the period for which the auction was conducted and that were not offered for sale in the auction. The base FTRs model also will include estimated uncompensated parallel flows into each interface point of the NEPOOL Control Area and estimated scheduled transmission outages.

(b) In accordance with the requirements of this Section and subject to all applicable transmission constraints and reliability requirements, the ISO shall determine the simultaneous feasibility of all outstanding FTRs not offered for sale in the auction and of all FTRs that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum megawatt quantities of the bids and offers, selects the set of simultaneously feasible FTRs with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected FTRs and there are insufficient FTRs to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the FTRs that can be awarded.

(c) FTRs shall be sold at the market-clearing price for FTRs between specified pairs of receipt and delivery points, as determined by the bid value of the marginal FTR that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all FTRs paths based on the bid value of the marginal Financial Transmission Rights, which are those FTRs with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each FTRs path relative to the marginal FTRs paths flow sensitivities on the binding transmission constraints.

7.3.7 Announcement of Winners and Prices.

Within four (4) business days after the close of an auction, the ISO shall post the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the auction and the price at which each FTRs was awarded. Results of the on-peak auction and off-peak auction will be posted separately. The ISO shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell.

7.3.8 Auction Settlements.

All buyers and sellers of FTRs between the same points of receipt and delivery shall pay or be paid the market-clearing price, as determined in the auction, for such FTRs.

7.3.9 Allocation of Auction Revenues.

All auction revenues, net of payments to entities selling FTRs into the auction, shall be allocated to the Transmission Customers, Congestion Paying Entities, NEMA LSE and entities that pay for new transmission upgrades as specified under Schedule 15 of the Tariff.

7.3.10 Simultaneous Feasibility.

The ISO shall make the simultaneous feasibility determinations specified herein using appropriate power flow models of contingency-constrained dispatch. Such determinations shall take into account outages of both individual generation units and transmission facilities and shall be based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction. The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient Congestion Charges to satisfy all FTRs obligations for the auction period under expected conditions.

7.3.11 [Reserved.]

7.3.12 Financial Transmission Rights in the Form of Options.

When the ISO has the necessary software and hardware, the FTR auctions shall allow for the acquisition of FTRs in the form of options as well as obligations.

ATTACHMENT 2

Attachment 2

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool and ISO New England Inc.	))))	Docket No. ER01-____-000

NOTICE OF FILING

(June 19, 2001)

Take notice that on June 19, 2001, the New England Power Pool Participants Committee and ISO New England Inc (the “Joint Filers”) made a joint filing requesting the Commission accept as a rate schedule for the New England markets the substance of the standard market design (“SMD Document”). In that filing, the Joint Filers have also requested that the Commission extend to September 15, the time for filing comments relating to the pending SMD filing by New England Power Pool in Docket No. ER01-2223-000 and the pending SMD filing by ISO New England Inc. in Docket Nos. ER01-2192-000 and EL01-85-000. The Commission has been asked not to and does not have to act on the filings in Docket Nos. ER01-2192-000, ER01-2223-000 and EL01-85-000 within 60 days of those filings. Amended notices in those Dockets are being issued simultaneously with this notice.

Any person desiring to be heard or to protest the SMD Document should file motions to intervene or protests with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, on or before June __, 2001. Any motions to intervene or to protest should be filed in accordance with Rules 211 and 214 of the Commission’s Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission to determine the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This submission may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance). Comments and protests may be filed electronically via the internet in lieu of paper. See, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site at http:/www.ferc.fed.us/efi/doorbel.htm.

David P. Boergers
Secretary

ATTACHMENT 3

Attachment 3

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

	)	
New England Power Pool	)	Docket No. ER01-2223-000
	)	

AMENDED NOTICE OF FILING

(June 19, 2001)

Take notice that on June 19, 2001, the New England Power Pool Participants Committee and ISO New England Inc. made a joint filing, assigned Docket No. ER01-____-000, which requests that the Commission extend to September 15, 2001 the time for commenting in the referenced docket, and requesting that the Commission not act in this Docket until 60 days after September 15, 2001.

Pursuant to that request, the date for filing comments in the captioned docket is hereby extended to September 15, 2001. Any person desiring to be heard or to protest such filing should file motions to intervene or protests with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, on or before September 15, 2001. Any motions to intervene or to protest should be filed in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission to determine the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of the original filing and the joint filing in Docket No. ER01-___-000 are on file with the Commission and are available for public inspection. This submission may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance). Comments and protests may be filed electronically via the internet in lieu of paper. See, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site at http:/www.ferc.fed.us/efi/doorbel.htm.

David P. Boergers
Secretary

ATTACHMENT 4

Attachment 4

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc.	)	Docket Nos. ER01-2192-000
	)	EL01-85-000

AMENDED NOTICE OF FILING

(June 19, 2001)

Take notice that on June 19, 2001, the New England Power Pool Participants Committee and ISO New England Inc. made a joint filing, assigned Docket No. ER01-____-000, which requests that the Commission extend to September 15, 2001 the time for commenting in the referenced dockets, and requesting that the Commission not act in these dockets until 60 days after September 15, 2001.

Any person desiring to be heard or to protest such filing should file motions to intervene or protests with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, on or before September 15, 2001. Any motions to intervene or to protest should be filed in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission to determine the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This submission may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance). Comments and protests may be filed electronically via the internet in lieu of paper. See, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site at http:/www.ferc.fed.us/efi/doorbel.htm.

David P. Boergers
Secretary