Development of New England Power Pool’s Proposed Markets

Philip A. Fedora
(pfedora@iso-ne.com)
ISO New England Inc., One Sullivan Road, Holyoke, MA 01040-2841

Abstract

This paper summarizes the bidding procedures proposed by NEPOOL for the Energy, Reserve, Automatic Generation Control (AGC), and Operable Capability markets. Experience with the Installed Capability market is also described. On October 29, 1997 FERC accepted NEPOOL’s previous filings proposing the implementation of the Installed Capability Market by November 1, 1997, but suspended its implementation for five months. The NEPOOL Installed Capability Market became operational on April 1, 1998. On July 23, 1998, the 36th Amendment to the NEPOOL Agreement was filed by NEPOOL on to comply with the requirements of FERC’s April 20, 1998 Order.

NEPOOL Participants have met throughout 1998 with ISO New England to define the proposed markets’ rules and bidding procedures. The bidding specifics are in the process of being finalized by the NEPOOL Regional Market Operations Committee. Subject to FERC approval, the target date for the proposed markets’ implementation is anticipated for December 1, 1998.

1. Introduction

NEPOOL was initially organized in 1971, pursuant to the New England Power Pool Agreement, dated September 1, 1971[1]. The 33rd Amendment to the NEPOOL Agreement[2] was filed on December 31, 1996 to comply with the requirements of FERC Order No. 888[3] comparability and non-discrimination requirements for ‘tight’ power pools, and included the Interim Independent System Operator (ISO) Agreement, a request for Section 203 approval to transfer control of the transmission facilities to the ISO, and the NEPOOL Tariff. A First Supplement[3] to the NEPOOL Agreement was filed on February 14, 1997, primarily to further define the proposed ISO by-laws, code of conduct and ethics policy, and provide revisions to the NEPOOL open access tariff.

On February 28, 1997 FERC[2] permitted the Tariff and Parts One (Definitions), Two (Governance), Four (Transmission Provisions) and Five (ISO and Other Provisions) of the Restated NEPOOL Agreement to become effective on March 1, 1997 subject to refund and further FERC orders.

On March 4, 1997 FERC issued Order 888-A[3] and modified its Pro Forma Tariff accordingly, giving all public utilities 120 days to reflect the corresponding tariff changes.

On June 25, 1997 FERC required NEPOOL to comply with eight conditions or requirements with respect to the establishment of the ISO. Further amendment to the NEPOOL Agreement was required in order to effect three of the terms.

On July 1, 1997 NEPOOL filed a Second Supplement[3] to the Agreement making revised Installed Capability Responsibility provisions effective as of November 1, 1997 and amend the NEPOOL Open Access Transmission Tariff in order to be in compliance with FERC Order 888-A.

On September 1, 1997, NEPOOL filed a Third Supplement to the Agreement[5] regarding their agreement in principle regarding how transactions across transmission interconnections between Participants and entities in New York and New Brunswick will be treated under the Tariff.

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On September 1, 1997, NEPOOL also submitted the 34th Amendment\(^6\) to the NEPOOL Agreement, to comply with FERC's terms in their June 25th Order.

On October 29, 1997 FERC issued an Order\(^7\) that accepted for filing the Second and Third Supplements of the Restated NEPOOL Agreement. With respect to the proposed markets, the October 29th FERC Order suspended the proposed new Installed Capability Market Responsibility provisions for five months, to become effective April 1, 1998.

On November 1, 1997, NEPOOL filed a Fourth Supplement to the Thirty-Third Amendment,\(^8\) to reflect a proposed resolution of issues concerning usage rights for NEPOOL interfaces and congestion costs.

On November 26, 1997, NEPOOL filed the Thirty-Fifth Agreement Amending the NEPOOL Agreement\(^9\) to take into account of the provisions of the October 29th Order which provides for the effectiveness on November 1, 1997 of the proposed change in time period for the recognition of load changes.

On December 30, 1997, NEPOOL filed a Fifth Supplement to the Thirty-Third Amendment,\(^10\) which revised the charges for an ancillary service provided under the NEPOOL Tariff and proposed rules for the power exchange.

On April 20, 1998 FERC issued an Order\(^11\) which required extensive changes to the Tariff, including the need to address rate design for point-to-point services and the allocation of point-to-point revenues. The Order also ruled on the provisions proposed for the Installed Capability market, NEPOOL treatment of transactions outside of the NEPOOL control area, and imposed a price cap on the Installed Capability market. FERC did not rule on the other six proposed markets.

On July 23, 1998, NEPOOL filed the 36th Amendment to the NEPOOL Agreement\(^12\) in compliance with the April 20th Order.

On August 17, NEPOOL filed the 37th Amendment the NEPOOL Agreement\(^13\), intended to amend the definition of the “Power Year” in the Restated NEPOOL Agreement provisions which determine the Installed Capability Responsibilities of NEPOOL Participants, to be effective November 1, 1998.

On September 14, 1998, ISO New England filed a motion at FERC\(^14\) to include its independent market assessment in the related docket and requested an Order permitting the market implementation on December 1, 1998.

The seven proposed NEPOOL market commodities are: Energy, four markets for ancillary services (Ten Minute Spinning Reserve (TMSR), Ten Minute Non-Spinning Reserve (TMNSR), Thirty Minute Operating Reserve (TMOR), Automatic Generation Control (AGC)) and two capacity markets (Operable Capability and Installed Capability).

## 2. The Energy Market

The Energy Market is a residual market; only the difference between a Participant’s energy resources and its energy obligations is traded in the ISO New England market. These resources and obligations include amounts covered by bilateral contracts. Hourly bids, expressed in $/MWh, are submitted on a day-ahead basis for the next 24 hours. ISO New England then schedules the generating units that will run the following day based on minimizing total costs in the energy market, as represented by the accepted bids. The market is settled after the fact on an hourly basis. All transactions are priced at the (ex post) energy clearing price. Payments/receipts are equal to the MWh bought/sold time the clearing price. Suppliers are paid for out-of-merit-order dispatch to alleviate transmission congestion on the basis of their bids submitted in the energy market.

## 3. The Ten Minute Spinning Reserve Market

The Ten Minute Spinning Reserve (TMSR) Market is a full requirements market. All TMSR is bought/sold through ISO New England. Bidding and settlement are done as in the energy market - hourly bids in $/MWh for the next day are submitted, and the markets are settled hourly after the fact. Given the units dispatched to provide energy, ISO New England selects the least-cost resources to provide the required TMSR, taking into account bid costs, lost opportunity costs, and production cost changes. When the market begins operation, only hydro units and dispatchable loads may bid into this market. Although they cannot bid, fossil-fueled generators can be selected to participate in the market based on lost opportunity costs and production cost changes. Designated resources are paid the energy clearing price for any MWh provided plus lost opportunity cost plus production cost changes plus the bid times the MW provided. The total cost of providing TMSR is shared proportionally by load.
4. **The Ten Minute Non-Spinning Reserve Market**

The Ten Minute Non-Spinning Reserve (TMNSR) Market is a full requirements market. All TMNSR is bought/sold through ISO New England. Bidding and settlement are done as in the energy market - hourly bids in $/MW for the next day are submitted, and the markets are settled hourly after the fact. Designated resources are paid the clearing price times the MW provided as reserved capacity. The total cost of providing TMNSR is shared proportionally by load.

5. **The Thirty Minute Operating Reserve Market**

The Thirty Minute Operating Reserve (TMOR) Market is a full requirements market. All TMOR is bought/sold through ISO New England. Bidding and settlement are done as in the energy market - hourly bids in $/MW for the next day are submitted, and the markets are settled hourly after the fact. Designated resources are paid the clearing price times the MW provided as reserved capacity. The total cost of providing TMNSR is shared proportionally by load.

6. **The Automatic Generation Control Market**

The Automatic Generation Control (AGC) Market is a full requirements market. All AGC is bought/sold through ISO New England. Bidding and settlement are done as in the energy market - hourly bids for the next day are submitted, and the markets are settled hourly after the fact. AGC is measured in reg's, which measure a unit's ability to follow load. Units that can provide AGC at lowest cost based bids, lost opportunity costs, and production cost changes are selected. Generators providing AGC are paid the clearing price for time on AGC times the number of reg's plus a payment for AGC service actually provided plus any lost opportunity cost. The total cost of providing AGC is shared proportionally by load.

7. **The Operable Capability Market**

The Operable Capability (OPCAP) Market is a residual market. Only the difference between a Participant’s operable capability resources and its operating capability obligation (load plus operating reserve) is traded through ISO New England. Bidding and settlement are done as in the energy market - hourly bids in $/MW for the next day are submitted, and the markets are settled hourly after the fact. A clearing price is calculated based on the bids of those Participants with excess operable capacity. Participants who are deficient in operable capability pay the clearing price for each MW to those who are in surplus and who bid a price less than or equal to the clearing price.

8. **The Installed Capacity Market**

The Installed Capability (ICAP) Market is residual market; only the difference between a Participant’s installed capability resources and its installed capability obligation (load plus installed operating reserve) is traded through ISO New England. Trading in this market occurs monthly; bids are submitted in $/MW-month on the last day before the month begins. A clearing price is calculated on the bids of those Participants with excess installed capacity. Participants who are deficient in installed capability pay the clearing price for each MW-month to those who are in surplus and who bid a price less than or equal to the clearing price.

The NEPOOL ICAP Market was implemented April 1, 1998. In order to comply with the conditional acceptance of the NEPOOL Agreement by FERC on April 20, 1998, the NEPOOL Executive Committee resolved to:

1. retain the Outside Transaction Adjustment (OTA) for the calculation of Capability Responsibility (CR) in April, 1998;
2. suspend the OTA for the CR calculation in May, 1998;
3. adopt the NEPOOL Tie Line Reliability Adjustment Procedure (TLRA) developed by the NEPOOL Market Reliability Planning Committee to replace the OTA in the CR calculation.

ISO New England provides a monthly preliminary NEPOOL Installed Capability Market Report (ICAP Report) on its web site (www.iso-ne.com). The monthly ICAP Report is intended to provide an estimated status of the NEPOOL ICAP Market. This is only an indication of how the monthly may settle, since a majority of the values on the report are preliminary. After the values have been finalized, the actual monthly ICAP market will be recalculated and a settlement issued.
The current status of the prior preliminary monthly ICAP Reports are summarized below. FERC currently has imposed a cap of $8,750/MW-month, pending the operation of the other six proposed markets.

<table>
<thead>
<tr>
<th>Month</th>
<th>Total Excess ICAP</th>
<th>Excess ICAP Sold To The Market</th>
<th>ICAP Market Clearing Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>April</td>
<td>1,325.61</td>
<td>550.76</td>
<td>3,964 (MW)</td>
</tr>
<tr>
<td>May</td>
<td>2,361.00</td>
<td>524.15</td>
<td>2,000 (MW)</td>
</tr>
<tr>
<td>June</td>
<td>1,310.57</td>
<td>309.16</td>
<td>1,500 (MW)</td>
</tr>
<tr>
<td>July</td>
<td>1,381.06</td>
<td>225.12</td>
<td>0 (MW)</td>
</tr>
<tr>
<td>Aug</td>
<td>1,394.77</td>
<td>223.22</td>
<td>0 (MW)</td>
</tr>
</tbody>
</table>

Note that Millstone Unit No. 3 established a capability rating equal to 1,140 MW on August 1, 1998.

9. ISO New England Assessment of the proposed NEPOOL Markets

Under the Interim Independent System Operator Agreement, ISO New England has the authority “to independently assess the competitiveness and efficiency of the NEPOOL Market”. ISO New England recently commissioned an independent review of the design and structure of the proposed NEPOOL wholesale electricity markets. ISO New England undertook this assessment prior to the implementation of the proposed markets to increase the likelihood that they will open and operate successfully.

The Markets have a scheduled implementation date of December 1, 1998, pending FERC approval. Key finding of the independent review:

1. NEPOOL should adopt a multi-settlement system with demand-side bidding capability. The assessment concluded that the current market structure, based on a “day ahead” unit commitment intended to be physically, but not financially binding, could unfairly advantage certain market players and also could result in a spot price that is inconsistent with the commitment made by generators.

2. The currently designed single settlements system can work for a short period of time provided there is an agreement in principle to switch to a multi-settlement system with demand-side bidding as soon as possible after the markets open.

3. The development and implementation of a location-based pricing congestion management system after the Second Effective Date as committed by NEPOOL in its filings to FERC.

4. The adoption prior to December 1, 1998, or as soon thereafter as practical of changes in the Ten Minute Spinning Reserve (TMSR) Market to eliminate double counting in the calculation of the TMSR clearing price.

The assessment concluded that although there are issues needing resolution to improve the longer term efficiency and competitiveness of the Markets, the Markets can be implemented as intended on December 1, 1998.

ISO New England, in conjunction with the NEPOOL Participants, plan to conduct tests of the proposed markets’ performance through so-called “mock” NEPOOL market simulations this fall. This will allow for testing of the NEPOOL Energy Management System (EMS), the unit commitment software, bidding mechanisms and billing procedures prior to the actual start of the markets, while providing training of ISO New England staff and NEPOOL Participants.

10. References


11. Acknowledgments

Many people have contributed to the conceptual design and proposed implementation of the NEPOOL Markets. NEPOOL Participants and ISO-NE staff, working through the NEPOOL Regional Market Operations Committee and NEPOOL Market Reliability Planning Committee have refined the initial concepts initially presented in the Restated NEPOOL Agreement. ISO New England’s Customer Services and Training staff have developed the courses and sessions designed to describe the current state of the market rules.

12. Biography

Philip A. Fedora holds a Master of Science degree in Electrical Engineering from the University of Pittsburgh. He is the Manager of Power Supply Reliability at ISO New England Inc. In this position his responsibilities include the calculation of NEPOOL Objective Capability and its Associated Parameters, NEPOOL Resource Adequacy Assessments, and projections of generating unit emissions associated with the anticipated future operation of the NEPOOL system. He is a registered professional engineer in the Commonwealth of Pennsylvania.