2007 Wholesale Markets Plan

Approved by the ISO New England Board of Directors

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Section 1
Introduction and Summary

This report describes ISO New England's (ISO) plans for the continued development of New England's wholesale electricity markets. As in previous Wholesale Markets Plans, the *2007 Wholesale Markets Plan* (WMP07) summarizes the market enhancements planned for the next several years. The primary focus of WMP07 is the implementation of the settlement agreement for the Forward Capacity Market (FCM), an auction-based locational capacity market for the New England region. The FCM is designed to work with the electric energy markets and the Ancillary Services Markets (ASM) to send price signals that will attract and sustain the resources needed for a reliable electric power system in New England, while minimizing costs to consumers.[1]

Over the past several years, the ISO, New England Power Pool (NEPOOL) participants, and state regulators have worked to improve the design of the wholesale electricity markets by developing markets for capacity and ancillary services.[2] This work culminated in the Federal Energy Regulatory Commission's (FERC) approval of Phase II of the Ancillary Services Market (ASM II) on May 12, 2006, and the FCM Settlement Agreement on June 16, 2006, making 2006 a landmark year for the region's wholesale electricity markets.[3,4] These approvals enable the ISO, NEPOOL, and state regulators to shift the focus of wholesale markets development from market design to market implementation. After implementing ASM II in October 2006, the region will begin to implement the FCM in 2007. This will be a multiyear process requiring considerable effort.

Section 2 of WMP07 summarizes New England's electric energy, ancillary services, and capacity markets and their interrelationships. Section 3 describes the status of the various projects discussed in the *2006 Wholesale Markets Plan* (WMP06), the primary focus of which was the implementation of the Locational Installed Capacity (LICAP) market and ASM II.[5] ASM II and related projects have been implemented on schedule, and the recent FCM settlement has superseded the LICAP implementation.

Section 4 presents the implementation plan and schedule for the projects included in WMP07. The individual projects are described in Section 5. While ISO and stakeholder efforts in 2007 will be dominated by the implementation of the FCM, the implementation of FERC's order on Long-Term Transmission Rights (LTTR) will also require significant effort. In February 2007, the ISO will file FCM market rules with FERC, and much of the preparation for the first FCM auction, scheduled for February 2008, will also occur in 2007.

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[1] The ASM includes a locational Forward Reserve Market (FRM) and a real-time market for acquiring operating reserves (part of ASM Phase II) and the Regulation Market, a market for selecting and paying for generation needed to manage small changes in system electrical load (part of ASM Phase I).

[2] NEPOOL was formed in 1971 by the region's private and municipal utilities to foster cooperation and coordination among the utilities in the six-state region and ensure a dependable supply of electricity. Today, NEPOOL members are ISO stakeholders and market participants.

[3] New England Power Pool and ISO New England Inc., *Order Accepting Ancillary Services Market Proposal*, Docket No. ER06-613-000, 115 FERC ¶61,175 (May 12, 2006).

[4] Devon Power LLC, *Order Accepting Proposed Settlement Agreement*, Docket Nos. ER03-563-030 and ER03-563-055, 115 FERC ¶61,340 (June 16, 2006).

[5] *Installed capacity* is the megawatt capability of a generating unit, dispatchable load, external resource or transaction, or demand-side resource that qualifies as participant in the ISO's ICAP Market per the market rules (see http://www.iso-ne.com/rules_proceds/index.html).

Section 6 describes ISO research and development initiatives to conduct simulations of the FCM to assure that this market will perform as designed. It also summarizes a project to improve market pricing to more accurately reflect out-of-merit dispatch costs. Section 7 describes two policy initiatives: a review of the cost-allocation procedures for second-contingency costs and efforts to improve the linkage between the wholesale and retail markets.

Section 2
Wholesale Electricity Markets: Their Functions and Interrelationships

Although not a detailed description of the ISO's specific market design, the following information describes the basic interdependence and structure of the wholesale electricity markets. Providing electricity at an efficient cost requires a set of wholesale markets that work together to efficiently price the electric energy and ancillary services needed to reliably provide electricity.

While the implementation of Standard Market Design (SMD) has significantly contributed to establishing efficient wholesale electricity markets, the wholesale electric energy market does not consistently clear at price levels that sustain the existing investment or promote the new investment needed to maintain system reliability.[6] One important reason the electric energy market does not clear at a sufficient level is that an existing offer cap limits electric energy offers to $1,000 per megawatt-hour (MWh).[7] This offer cap is needed because the electric energy market does not have adequate demand participation for the market to clear when the demand for electricity approaches or exceeds the available supply, making the market vulnerable to the exercise of market power. The combination of the offer cap and the lack of demand participation in the electric energy market prevents this market from efficiently pricing electricity during hours of peak use. To achieve efficient pricing, a capacity market is needed to supplement the electric energy market and ASM.

This section describes the functions of the wholesale electricity markets and how, collectively, they price the services needed for reliable and economic system operation.

2.1 The Electric Energy Market

The electric energy market is the essential element of the wholesale electricity markets. Its main function is to determine efficient wholesale electric energy prices in real time and on a day-ahead basis. Electric energy prices vary in real time because of changing consumption and sources of production. The SMD electric energy market balances supply and demand and establishes market-clearing prices on a five-minute basis using locational marginal pricing, efficiently pricing all locations on the electricity grid. This means that areas that incur significant transmission losses, or that cannot import sufficient capacity to serve the demand for electricity, experience higher locational marginal prices (LMPs). Higher LMPs signal potential investors that investment is needed in these locations. Higher LMPs can also signal consumers to use less electricity, if retail rate designs are structured so that the electric energy prices are transparent to consumers and responding to these prices affects consumer payments.

The ISO commits and dispatches generating units in economic-merit order—the generators with the lowest-price offers are committed and dispatched first, and increasingly higher-priced generators are brought on-line as demand increases. Competition among generators should drive their offers down to their short-run marginal costs, which are primarily fuel costs. However, since market-clearing prices

[6] New England implemented SMD on March 1, 2003. The SMD electric energy market structure incorporates locational marginal pricing, multiple settlements in the Day-Ahead and Real-Time Energy Markets, and risk management tools to hedge against the impacts of higher differentials in locational marginal prices when transmission congestion occurs.

[7] The $1,000 offer cap was approved by FERC in *Order on Complaint and Conditionally Accepting Market Rule Revisions*, Docket Nos. EL00-83-000 and 001, ER00-2811-000 and 001, ER00-2937-000, EL00-62-000, and ER00-2052-000, 92 FERC ¶ 61,065 (July 26, 2000).

are based on the last generating unit needed to meet demand, most generators (i.e., generators other than the last one dispatched to meet demand) earn revenues through the electric energy market in excess of their short-run variable costs for fuel and other operating expenses. These "inframarginal revenues" contribute to the recovery of fixed costs, the largest portion being capital costs.

2.2 Ancillary Services Markets

Because the status of any major system element—such as a generator, a transmission line, or a load—can suddenly change, system operators need resources that can quickly respond to events that arise at any given moment. Typical real-time operational contingencies that the system operator must protect the system against include the sudden loss of a major transmission line or a large generating station. If a large generating station trips off line, the system operator must have sufficient resources to replace this sudden loss. This will maintain the balance of supply and demand and the integrity of the New England transmission system as well as the systems interconnected with the New England system. Without resources to replace the sudden loss of such system elements, load would need to be shed to preserve the real-time balance of supply and demand. In extreme conditions, the entire network could collapse and cause a blackout. Therefore, ancillary services must be available to maintain the reliability of the system in real time. Since transmission constraints may prevent generation in one area from responding to contingencies in another area, the value of ancillary services varies by location.

Ancillary services are generally provided by resources that are not providing electric energy. Since these resources do not participate in the electric energy market while providing ancillary services, they do not earn revenues from that market. Therefore, a separate market is needed for obtaining ancillary services and compensating the resources that provide these services. The ASM is narrowly constructed for resources that provide ancillary services and are not intended to replace the capacity market or the electric energy market, which include all resources.

System operators must be able to call on a variety of ancillary services to maintain real-time system reliability. These services, provided through the ASM, include the following:

- Regulation services, also known as automatic generation control (AGC), which allow the system operator to physically balance supply and demand on a minute-to-minute basis
- 10-minute spinning reserves (TMSR), provided by resources already synchronized to the grid and able to provide output within 10 minutes
- 10-minute nonspinning reserves (TMNSR), provided by resources not currently synchronized to the grid but capable of starting and providing output within 10 minutes
- 30-minute operating reserves (TMOR), provided by resources not currently synchronized to the grid but capable of starting and providing increased output within 30 minutes

To maintain system reliability in specific locations or circumstances, the system operator needs other specialized ancillary services, such as the following:

- Voltage support, formally called volt ampere reactive (VAR) support, which allows the New England Control Area to maintain transmission voltages within acceptable limits by operating generation resources in a way that produces or absorbs reactive power[8]

- Black-start capability, which is provided by specific generators interconnected to the transmission or distribution system at strategic locations and involves restoring generation to restart the transmission system following a systemwide blackout

Since only a few resources are capable of providing these highly specialized services, the services do not lend themselves to being bought and sold in the ASM. Resources currently provide these ancillary services on a cost-of-service basis and will likely continue to do so in the near future.

2.3 Capacity Market

As noted above, the offer cap on the electric energy market prevents the market from sending the price signals needed to assure short-term reliability through long-term system resource adequacy. A capacity market supplements the electric energy market by substituting for the price signals lost because of this market cap. If properly designed, the combination of the capacity and energy markets and the ASM should provide the price signals needed to maintain system reliability.

The capacity market responds to the ISO's need to meet the Northeast Power Coordinating Council (NPCC) and ISO resource-planning reliability criterion intended to assure that sufficient capacity is available to meet demand.[9] This criterion requires the power system to have enough installed capacity to prevent the disconnection of firm customer load more frequently than one day in 10 years. This requirement is referred to as the Installed Capacity Requirement (ICR).

As discussed in more detail in Section 5.1, the Forward Capacity Market is being designed to supplement the electric energy markets and ASM and replace the existing capacity market to ensure the reliability of the New England electricity grid at an efficient cost to consumers. The FCM will send appropriate price signals to attract new investment and maintain existing resources. It will also provide a mechanism for discovering the cost of new entry (CONE) and offer new generation the option to make up to a five-year financial commitment on the basis of the discovered CONE.

[8] The Northeast Power Coordinating Council defines *control areas* as electric systems bounded by interconnection metering and communication systems that control generation to maintain an import-export schedule with other control areas and contribute to regulating the frequency of the interconnection. For further information, see http://www.npcc.org/default.cfm. Also see http://www.nerc.com/.

[9] Additional information on the NPCC reliability criterion can be accessed at http://www.npcc.org/criteria.asp.

Section 3
Update of the *2006 Wholesale Markets Plan*

This section summarizes the status of the projects discussed in WMP06. The effects of demand participation on the wholesale electricity markets and changes to the market rules are also discussed.

3.1 Projects in the *2006 Wholesale Markets Plan*

Table 3-1 summarizes the commitments included in WMP06 and the ISO's progress toward meeting these commitments. Two events during 2005 affected the schedule presented in WMP06. First, the ISO was required to expend considerable effort in the fourth quarter of 2005 to support the development of the 2005/2006 Winter Action Plan. This was necessary to minimize the risk of fuel-supply disruptions caused by Hurricanes Katrina and Rita. At the same time and through the first quarter of 2006, the ISO and its stakeholders devoted significant time and resources to the LICAP settlement proceedings that resulted in the Forward Capacity Market Settlement Agreement. Section 3.2 describes the major changes in WMP06 projects.

Table 3-1
***2006 Wholesale Markets Plan* Commitments**

Project	Earliest Implementation Date Forecasted	Status Update
Locational Installed Capacity	October 1, 2006	Superseded by FCM
Southwest Connecticut Load Zone	January 1, 2006	Need obviated by transmission enhancements
Interregional Transaction Scheduling	First quarter 2006	Postponed pending review by NYISO and ISO New England
Ancillary Services Markets Phase II ***- Locational forward reserves*** ***- Joint optimization*** ***- Demand participation***	October 2006	In service
Special Case Nodal Pricing (Asset Related Demand or ARD)	October 2006, with ASM Phase 2	In service
Small-Resource Reserve Project	October 2006	In service
Pricing of External Nodes (1385)	October 2006	Scheduled for June 2007
Partial Delisting Enhancements	June 2007	In service
Combined-Cycle Modeling	May 2006	Scheduled for fourth quarter 2006
Long-Term Cold-Snap Recommendations	Fourth quarter 2006	On schedule

3.2 Major Changes in Projects Comprising WMP06

This section summarizes the major changes in projects that were included in the *2006 Wholesale Markets Plan*.

3.2.1 Locational Installed Capacity Market

On March 1, 2004, the ISO filed a LICAP design with FERC that included a sloped demand curve to address ICAP price volatility and a locational clearing process to appropriately price capacity on a locational basis. FERC approved the overarching design of the ISO's LICAP proposal but set certain issues for hearing. On June 15, 2005, the administrative law judge in the LICAP proceeding issued an initial decision. Several parties took exception to that decision and requested that FERC hold an oral argument in the LICAP proceeding, which FERC granted. On September 20, 2005, the FERC held oral arguments, the result of which was to give the parties to the proceeding further opportunity to develop an alternative to LICAP through settlement discussions. The settlement process was successful; on March 1, 2006, a LICAP settlement that resulted in the creation of the Forward Capacity Market was filed with FERC, and on June 16, 2006, FERC issued an order approving it. This settlement replaced LICAP with the Forward Capacity Market, making the implementation of LICAP unnecessary.

3.2.2 Southwest Connecticut Load Zone

The creation of the Southwest Connecticut (SWCT) load zone was planned in anticipation of the implementation of LICAP. As a result of the settlement process described above, the FCM has superseded LICAP. The timeline of the FCM and the transmission improvements currently being planned and constructed eliminate the need for to create a SWCT load zone. If these transmission projects are not completed or are significantly delayed, creating a SWCT load zone may have to be revisited.

3.2.3 Day-Ahead Load-Response Program

On June 1, 2005, the ISO implemented a Day-Ahead Load-Response Program (DALRP) for customers that can offer load reductions concurrent with the Day-Ahead Energy Market. The current program design uses a "sequential-clearing" methodology to determine whether to accept a DALRP offer. With this methodology, DALRP offers are accepted after an approved solution to the Day-Ahead Energy Market has been determined. In its approval of the DALRP, FERC directed the ISO to implement an "integrated-clearing" methodology by June 2007. In the integrated-clearing methodology, the DALRP offers are directly integrated into the Day-Ahead Energy Market clearing process. Because implementing the FCM and LTTRs will require significant resources in 2007, and the ISO believes the goals of the DALRP integrated-clearing approach will be accomplished through developments in related projects (see Section 3.3 and Section 5.1), the ISO has filed with FERC to postpone the implementation of the integrated-clearing methodology. The ISO instead seeks to file a report no later than December 28, 2007, on the integration of demand resources and the implementation of appropriate solutions.

3.3 Increasing Demand Participation in Wholesale Electricity Markets

Increasing demand participation in the wholesale electricity markets is an important objective of the ISO's wholesale market development. Two projects in WMP06 make considerable progress in meeting this objective. ASM II provides the software and market rules to enable large loads (demand greater than 5 MW) to participate directly in the wholesale electric energy and reserve markets. The Small-Resource Reserve Pilot Project (SRR Pilot) is designed to determine whether small demand and supply resources (less than 5 MW) that are not electronically dispatched by the ISO can reliably provide reserves. If the results of the pilot are positive, the ISO will file rule changes with FERC, developed through the appropriate stakeholder process, to permit small resources to participate in the ASM. The ASM and SRR Pilot, as described in the sections below, provide the infrastructure for demand to fully participate in the wholesale electricity markets.

To obtain the demand participation necessary to make the wholesale electricity market fully efficient, retail rate structures that link wholesale price signals to retail markets are needed. Section 7.2 describes the ISO's efforts in this area in more detail.

3.3.1 Asset-Related Demand

Load will be able to participate in the wholesale electric energy market by registering as an asset-related demand (ARD) resource. An ARD resource is a 5 MW or greater individually metered physical load. A non-dispatchable ARD resource may bid into the Day-Ahead Energy Market and will be settled at the nodal price. A dispatchable ARD resource may also participate in the day-ahead market and be settled at the nodal price but will also be able to participate in the Forward Reserve Market and Forward Capacity Market. ARD resources will be eligible to participate in the electric energy and reserves markets when ASM II is implemented.

3.3.2 Small-Resource Reserves Pilot Project

Individual demand-response resources are relatively small, and it is not cost effective to equip them with the sophisticated metering and communication equipment that system operators use to monitor system status and relay dispatch instructions to larger resources. Thus, small resources are effectively prevented from participating in the reserve markets. The ISO plans to address this barrier by implementing a Small-Resource Reserves Pilot Project. The ISO will assess the ability of small demand and supply resources to provide operating reserves and investigate cost-effective communication and telemetry solutions for allowing such resources to participate in the market. NEPOOL approved the SRR Pilot rules in June 2005, which were then filed with FERC in September 2005. FERC approved the SRR Pilot on November 29, 2005. The program was initiated on October 1, 2006, and will be ongoing through 2007.

3.4 Additional Changes to the Market Rules in 2006

In addition to the projects listed in Table 3-1, the ISO initiated several other changes to the market rules, as described below.

3.4.1 2005/2006 Winter Action Plan

In late fall 2005, the ISO expedited the implementation of the 2005/2006 Winter Action Plan. The plan included several changes to the market rules to mitigate the impact of possible gas-supply interruptions and extreme cold weather on market and system operations. The NEPOOL Participants Committee supported the rules, which were implemented with a sunset date of March 31, 2006. At

the time the temporary Winter Action Plan was approved, stakeholders and the ISO agreed to reevaluate the plan to determine which provisions, if any, should be made "permanent."[10]

The 2005/2006 Winter Action Plan included the following items:

- Start-up and no-load offer prices were daily biddable parameters instead of bi-monthly biddable parameters.
- Emergency energy transactions were excluded from the allocation of real-time Net Commitment-Period Compensation (NCPC) charges.[11]
- Posturing of resources: [12]
    - Real-time load obligations, not real-time load-obligation deviations, were used for allocating posturing costs.
    - Generators would be reimbursed for incurring out-of-pocket fuel costs as a consequence of a posturing action.
- A supplemental demand-response program was initiated to procure an additional 400 MW of capacity that would be used during periods of capacity shortage.

3.4.2 Transition Market Rules for the Forward Capacity Market

The FCM Settlement Agreement requires compensation for all existing installed capacity resources during a transition period. During the second quarter of 2006, the ISO initiated changes to Section 8 of Market Rule 1 to implement the interim compensation arrangements.[13] These changes were filed with FERC in September 2006. The transition period begins in December 2006 and ends with the beginning of the commitment period for the first Forward Capacity Auction (FCA), which is expected to be June 1, 2010. The transition payments will begin at $3.05/kilowatt (kW)-Month and increase to $4.10/kW-Month over the transition period. The capacity product is defined as seasonal unforced capacity (UCAP) using a weighted EFORd availability metric.[14]

[10] The provisions of the Winter Action Plan could be changed or eliminated in the future but would be permanent in the sense that they would not automatically expire.

[11] Net Commitment-Period Compensation is the methodology used to calculate payments to resources for providing operating or replacement reserves in either the Day-Ahead or Real-Time Energy Markets (subject to limitations). The accounting for the provision of these services is performed daily and considers a resource's total offer amount for generation, including start-up fees and no-load fees, compared with its total electric energy market value during the day. If the total value is less than the offer amount, the difference is credited to the market participant. For more information, see Market Rule 1, Section III, *Appendix F, Net Commitment Period Compensation Accounting*, at http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_appendix_f.pdf.

[12] *Posturing* refers to instances in which generators are directed to operate below their economic dispatch point for reliability reasons.

[13] The ISO's Market Rule 1, *Standard Market Design*, issued December 24, 2004, can be accessed at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[14] *Unforced capacity* is the difference between the installed capacity associated with a generating resource and that resource's amount of forced outage (i.e., the amount of capacity that is out of service because of the discovery of a problem that must be repaired as soon as crews, equipment, corrective dispatch actions, or a combination of all measures can be activated to allow the work to be performed). *EFORd* is the equivalent forced-outage rate of a resource during a demand period. For more information, see the ISO's *2005 Reliability Report* at http://www.iso-ne.com/pubs/arr/index.html.

3.4.3 FCM Market Rule 1 Revisions

The settlement agreement requires the ISO to file FCM market rules with FERC by February 15, 2007. Compliance with this condition entails replacing Section 8 of Market Rule 1, as well as revising other sections of the market rule to conform to the agreement. New provisions of Market Rule 1 will be drafted during the second half of 2006. The provisions will be coordinated through the NEPOOL stakeholder process and through separate working groups and meetings involving state regulators.

Section 4
Implementation Approach and Schedule

The *2007 Wholesale Markets Plan* comprises multiyear projects that were started in 2006 and scheduled for completion in 2007. Table 4-1 summarizes the project-release schedules, which are described in more detail in Section 5.

Table 4-1
Project-Release Schedule for WMP07

Project	Project Status	Market Design Schedule	Earliest Implementation Date
Forward Capacity Market—Transition	Implementation underway	October 1, 2006	December 2006
Forward Capacity Market—Forward Capacity Auction	Implementation initiated during the second quarter 2006	February 15, 2007	First auction: February 2008
Forward Capacity Market—Winter Operations	Work to begin following completion of FCM market rules	Subject to stakeholder discussions	Winter 2010/2011
Long-Term Transmission Rights	Development underway	January 2007	Third quarter 2007
Pricing of External Nodes (1385)	Design effort underway	Completed	June 2007
Interregional Transaction Scheduling	Alternate designs being discussed	Subject to stakeholder discussions	Subject to stakeholder discussions
Winter Operations—Appendix H	Development effort underway	October 2006	December 2006

To obtain the benefits associated with the multiyear WMP07 projects, NEPOOL stakeholders and regulators must agree on design specifics well in advance of the projects' scheduled release dates. Consensus promotes the more timely completion of projects and the submittal of proposed rule changes to FERC with stakeholder approval. Detailed market designs can be implemented in a timely manner only with sufficient lead time for system and software development. Additionally, significantly changing a market design near its planned release date may delay the project and prevent its completion on schedule.

Section 5
Project Descriptions

This section provides details about the projects listed in Table 4-1. These projects are intended to create wholesale electricity markets that efficiently price the products and services needed to reliably operate the power system in the short term, as well as ensure long-term resource adequacy. Well-functioning markets yield transparent prices that enable market participants to make efficient consumption, production, and investment decisions.

5.1 Forward Capacity Market

On June 15, 2006, FERC approved a settlement agreement filed on March 1, 2006, that resolved significant issues with the LICAP market design included in the initial FERC decision of the prior year (June 15, 2005) (see Section 3.2.1).[15] The auction-based FCM is a locational capacity market intended to send appropriate price signals to attract new investment and maintain existing resources where and when they are needed, thus ensuring the reliability of the New England electricity grid. The FCM auction allows new capacity to set the market clearing price, while accounting for locational capacity requirements, thereby providing a market-based measure of the cost of new entry. Features of the FCM are as follows:

- **The capacity product—**Different types of capacity resources will be able to participate in the FCA:
    - Generation plants
    - Intermittent resources (e.g., wind, solar, and hydro)
    - Demand resources, including energy-efficiency assets, located in New England
    - Imports of capacity resources from outside New England
- **Planning period—**Each auction will be held about three years in advance of its commitment period.
- **Demand participation in the FCM—**Demand can participate in the FCM as one of the several types of demand resources, including real-time demand response, load management, and energy efficiency. The FCM will be the first capacity market in the country to enable energy-efficiency assets to participate as a resource in a capacity market. Load can also participate more traditionally in the market by reducing consumption at the time of system peak to reduce its share of market costs.
- **Commitment period—**The commitment period is the time period during which capacity must be delivered. Existing capacity has a one-year commitment period. New capacity can choose a commitment period of up to five years. Each period coincides with the June-to-May power year. To allow sufficient time for new resources to begin development and for the implementation of the FCM, the first FCA will be held during the first quarter of 2008 for a commitment period beginning June 10, 2010.

[15] Devon Power LLC, *Order Accepting Proposed Settlement Agreement*, Docket Nos. ER03-563-030 and ER03-563-055, 115 FERC ¶61,340 (June 16, 2006).

- **FCM auctions—**The starting price for the first auction will be $15.00/kW-Month, or twice the initial value of the CONE, which is set at $7.50/kW-Month before any auction results are available. In compliance with the FCM Settlement Agreement, the CONE will be adjusted over the first few auctions to phase in the actual auction clearing prices that result from the FCA. In the descending-clock format of the FCA, the price will be decreased until the quantity of capacity remaining in the auction equals the quantity of capacity needed. The final price of a competitive auction is expected to be well below the $15.00 starting price. Because the FCM is a new design, the first three successful auctions will have a "collar" between $4.50/kW-Month and $10.50 per kW-Month. The FCM design also contains pricing provisions for situations when supply is inadequate or competition is insufficient because of a lack of new resources.

- **Installed Capacity Requirement—**Before each FCA, New England's ICR will be calculated for each power year up to and including the commitment period for that FCA. The ICR will be determined in accordance with the existing one-day-in-10-year resource planning reliability criterion as stated in ISO Planning Procedure No. 3, *Reliability Standards for the New England Area Bulk Power Supply System* (PP 3), and as modified by the Installed Capacity Working Group.[16]

- **Performance incentives—**These incentives are an important part of the FCM design. Payments to capacity resources are based on the availability of the resources when the system most needs the capacity; failure to perform will reduce compensation for these resources.

- **Peak-energy rents—**The FCM also provides for reduced capacity payments when a unit with a high thermal-conversion heat rate might be expected to operate. This "peak-energy rent" (PER) reduction is intended to accomplish the following:

    - Provide disincentives for suppliers to raise prices in the electric energy market when electric energy is in short supply
    - Hedge load against electric energy price spikes
    - Assure capacity and electric energy revenues do not result in double payments

- **Transition period—**Because the first FCA is scheduled for 2008 and the associated commitment period will not begin until 2010, the settlement included a provision for transition capacity payments to all listed installed capacity resources. These payments, negotiated between supply and load, will start on December 1, 2006. The transitional capacity market will also include payments to new energy-efficiency assets that register in the market. These transition payments will be netted against payments under reliability agreements and locational Forward Reserve Market (FRM) payments.[17]

- **Winter operations—**The settlement agreement included several provisions concerning potential natural gas fuel-supply issues inherent in winter operations:

    - Advancing offer-submission deadlines for the Day-Ahead Energy Market

[16] The procedure can be accessed at http://www.iso-ne.com/rules_proceds/isone_plan/PP3_R2.doc.

[17] Reliability payments are payments to generators providing first-contingency or second-contingency operating reserves. Locational Forward Reserve Market payments are payments to generators providing TMOR and TMNSR. For additional information, see the ISO's *2005 Annual Markets Report* at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

- Firming up the supply of an additional 1,000 MW of supplemental natural gas reserves for peak-load periods of the day
- Attaining confirmation from all gas-fired resources that they will nominate sufficient fuel to deliver the electric energy and reserves scheduled in the day-ahead market

These provisions will be in effect beginning in the 2010/2011 winter period.

5.2 Long-Term Transmission Rights

In compliance with the *Energy Policy Act of 2005*, FERC issued a Notice of Proposed Rulemaking (NOPR) on February 2, 2006, that provides guidance for designing, implementing, and administering a market for long-term firm transmission rights.[18,19] LTTRs provide the holder with rights to use specific transmission lines for a period greater than one year. The proposed rule in the NOPR provides a framework within which a Regional Transmission Organization (RTO), in conjunction with its market participants, could design and implement an LTTR market.

During spring 2006, the ISO and the NEPOOL Markets Committee formed the LTTR Working Group, which began reviewing how to implement LTTRs in New England. On July 20, 2006, FERC issued a final rule on LTTRs.[20] The ISO will be working with its stakeholders to file tariff language to comply with the FERC order.

5.3 Pricing of External Nodes (1385 Line)

The Long Island Power Authority (LIPA) has asked the New York ISO (NYISO) and ISO New England to develop the tariff and rule changes and the software changes necessary to separately schedule and dispatch transactions over the 1385 line that connects Southwest Connecticut and Long Island. Separating these transactions could improve the efficiency of the transactions between Long Island and Southwest Connecticut. ISO New England, NYISO, and LIPA have developed a proposal that addresses the relevant operational and tariff issues. ISO New England has discussed this proposal with its stakeholders and is currently finishing the design. Resource limitations have delayed the project from June 2006 until June 2007.

5.4 Interregional Transaction Scheduling

The Interregional Transaction Scheduling (ITS) project was initiated to address anomalous price differentials observed between the New York and New England markets when unused transfer capability remained on the interface. Efficient markets should yield prices that converge at the border. ITS is an important component of the market design because it is intended to ensure that by maximizing the use of the interface, shortage pricing occurs only when truly necessary.

Since arbitrage by market participants has not eliminated the price differences, the two ISOs and market participants conducted a joint project to evaluate the anomalous price behavior. A two-phase pilot project emanated from this effort.

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[18] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending *Federal Power Act* to add a new Section 216).

[19] FERC, Notice of Proposed Rulemaking, Order No. 681, *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Docket Nos. RM06-8-000 and AD05-7-000 (February 2, 2006).

[20] FERC, Final Rule, Order No. 681 *Long-Term Firm Transmission Rights in Organized Electricity Markets Under RMO6-8*, Docket No. RM06-8-000 (July 20, 2006), 71 *Federal Register* 43564 (August 1, 2006).

On October 24, 2005, ISO New England and NYISO issued a report on the first pilot test. A joint meeting of New York and New England stakeholders to review the pilot test report and further develop participant-based proposals was held on November 14, 2005. The report of the Joint Northeast Board on Economic Dispatch recommends that the two ISOs work together and with their market participants toward developing mechanisms to more efficiently dispatch the region's resources.

In 2007, ISO New England and NYISO look to evaluate a participant-initiated proposal for intra-hour transaction scheduling. The proposal would allow transactions to be scheduled on shorter notice and, potentially, for shorter duration. The shorter timeframes would allow participants to more quickly respond to price differences between the two areas.

5.5 Winter Operations—Appendix H

In response to concerns about winter operations and in compliance with a FERC order in Docket No. ER05-508, in January 2005, the ISO filed with FERC Appendix H to Market Rule 1.[21] Appendix H contains special provisions relating to the dispatch and operation of the New England wholesale power markets during extreme cold-weather conditions. As provided in the Appendix H Settlement Agreement of March 2005, the ISO filed a revised Appendix H on September 8, 2005, which FERC approved on September 28.[22] This version became effective on November 15, 2005, and had a sunset date of April 2006. [23, 24]

For winter 2006/2007 and subsequent winters, the ISO will file with FERC an updated version of Appendix H that will contain the following provisions:

- A revised day-ahead market timeline will close the Day-Ahead Energy Market by 9:00 a.m. when a cold-weather event is declared.

- Under the revised day-ahead market timeline, gas-fired units must notify the ISO by the close of the re-offer period that they have confirmation of a nomination or evidence of sufficient fuel supplies to meet their energy schedules.

- No new economic outages will be granted to capacity resources when a cold-weather warning or event is declared, and all economic outages for capacity resources will be canceled for the day that a cold-weather event is declared.

- Generators that encounter extraordinary fuel expense will be compensated.

These provisions will enable the ISO to forecast, schedule, and operate the system with greater certainty and will facilitate higher unit availability during cold-weather conditions.

[21] Refer to *FERC Order on Appendix H to Market Rule 1*, Docket No. ER05-508-003, 110 FERC ¶ 61,202 (March 2, 2005).

[22] FERC, *Certification of Uncontested Partial Settlement, Request for Expedited Action, and Request, in the Nature of a Rule 710 Motion, for Commission to Decide Remaining Issue*, Docket No. ER05-508-003, 112 FERC ¶ 63,033 (September 30, 2005).

[23] See *FERC Order Approving Partial Settlement and Accepting, as Modified, Last Resort Requirement*, FERC Docket No. ER05-508-000, 508-001, and 508-003, 113 FERC ¶ 61,175 (November 17, 2005).

[24] The Appendix H used for winter 2005/2006, which expired on April 15, 2006, is available in the ISO Web site archive at http://www.iso-ne.com/regulatory/tariff/sect_3/_Appendix_H/index.html.

Section 6
Research and Development

The ISO is undertaking projects to improve the testing of new market designs and capture out-of-merit dispatch costs in real-time reserve pricing.

6.1 Market Simulator

New England's wholesale electricity markets must be rigorously designed and tested. They include several billion dollars in transactions per year, and changes to the markets affect decisions that involve large sums of money. The ISO is developing a market simulator to improve the testing of new market designs. As part of this effort, the ISO and the Electric Power Research Institute (EPRI) are developing a market simulator to evaluate the Forward Capacity Auction. The ISO intends to use the market simulator to help assure that the FCM rules are complete and will work as anticipated.

6.2 Improved Market Pricing to Reflect Out-Of-Merit Dispatch Costs

The current pricing design for the electric energy market does not explicitly model out-of-merit dispatch costs. Fully including the out-of-merit commitment and dispatch costs in electric energy or reserve pricing is an unresolved industry-wide problem. Including these costs in the pricing design would give resource providers price signals that would likely improve the efficiency of providing electric energy and reserve products, which would lower overall electricity costs. Capturing such costs in electric energy and reserve pricing would also improve the ability of market participants to formulate financial hedges against such costs.

The ISO is currently evaluating how to capture these out-of-merit dispatch costs in real-time reserve prices. To address this problem, the ISO is investigating a market-pricing enhancement that would set a local 30-minute reserve floor price on the basis of the cost of the resource required to meet the local reserve requirement. The net result would increase both the local reserve price and the electric energy price when the ISO commits resources out of merit to meet second-contingency requirements.

The ISO is also working to improve the modeling of transmission constraints in both the day-ahead and real-time markets to improve the dispatch of generation and minimize out-of-merit commitments. Further, to ensure consistency between the day-ahead and real-time limits, the ISO will evaluate the underlying assumptions used in calculating these limits.

Section 7
Policy Issues

To further improve the markets, the ISO is evaluating several policy issues, including the allocation of second-contingency costs and the linkage between the wholesale and retail electricity markets.

7.1 Allocation of Second-Contingency Costs

The ISO must operate the system to meet several operating-reserve criteria.[25] These criteria require the system to have a specified amount of operating reserves to cover the loss of the single largest transmission unit or generation resource plus additional reserves to account for the possibility of second-contingency losses. The second-contingency criterion specifies the amount of reserves that must be available within 30 minutes to replace the operating reserves lost by the failure of the first-contingency resource. In constrained areas of the system, reliability resources are committed on the basis of second-contingency protocols, as described in Schedule 19 of the ISO's *Open Access Transmission Tariff* (OATT).[26]

Generating resources that respond to local second-contingency situations in constrained areas often receive out-of-market compensation paid by load-serving entities in the New England Control Area.[27] These out-of-market costs, which have spiked on several occasions, are often caused by local reliability issues that may signal the need for transmission system enhancements. How these costs are allocated has become a source of concern for many market participants. As a result, the ISO has agreed to work with stakeholders to review the relevant cost-allocation procedures. During the fourth quarter of 2006, the ISO will conduct a preliminary analysis to identify the scope of the work effort. The review is anticipated to cover the following topics:

- The current cost-allocation process and underlying cost-causation principles and incentives
- Historical costs and rule changes from the beginning of SMD
- Cost-allocation practices of other ISOs and RTOs
- Study of alternative methods of cost allocation

An initial review of local second-contingency costs is scheduled for completion during 2007. Any final recommendations or conclusions from this effort will be made following discussion with stakeholders.

[25] The ISO's operating-reserve requirements are established in Operating Procedure No. 8, *Operating Reserve and Regulation* (OP 8), and Operating Procedure No. 19, *Transmission Operations* (OP 19). For additional information, see http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html and http://www.iso-ne.com/rules_proceds/operating/isone/op19/index.html.

[26] The OATT, available at http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html, is part of FERC Electric Tariff No. 3, *ISO New England Inc. Transmission, Markets, and Services Tariff.* See http://www.iso-ne.com/regulatory/tariff/index.html.

[27] The output from generators that provide the electric energy needed for reliability purposes often displaces less-expensive electric energy. Consequently, these generating units cannot set LMPs and are thus paid out-of-market compensation costs, additional compensation for the difference between their operating costs and the LMP.

7.2 Wholesale–Retail Market Linkage Issues

Consumers' ability to capture the benefits of competitive electricity markets depends on ensuring consistency between the design and administration of the competitive wholesale market and the retail markets. It also depends on having retail rate structures that provide end-use customers with reliable and efficiently priced electricity service. Inconsistencies between wholesale and retail market policies result in market inefficiencies. In New England, for example, wholesale markets are designed to reflect geographical and temporal differences in power costs, which provide economic incentives for making investments and providing demand-response levels where and when they are most beneficial. However, these efforts are currently neutralized by retail rate designs, governed by state regulatory policy, that mask these geographical and temporal cost differences.

State policies affecting the pricing and procurement of Provider-of-Last-Resort (POLR) services could better align retail and wholesale markets, which would improve the efficiency of the region's electricity markets.[28] For example, greater use of dynamic pricing—retail prices that vary more directly with changes in wholesale spot-market electric energy prices—applied to price-responsive customers will likely be the most direct and cost-effective way to increase the responsiveness of demand to wholesale spot-market electric energy prices. This type of pricing will have the most value during periods of capacity shortages and price spikes.

The ISO supports efforts by market participants and state policymakers to improve the linkages between wholesale and retail markets in the area of demand response. However, because of the resources that will be required in 2007 to implement the FCM, the ISO's participation in these efforts may be limited during this year; the ISO anticipates greater participation in these efforts in the future.

[28] POLR services are also known as Standard Offer, Transitional Standard Offer, Default, Basic Electric, or Last-Resort service. In states that allow retail competition, Provider-of-Last-Resort service is provided to end-use customers who have not elected to take generation service from a competitive retail supplier. Typically, the distribution company or a state agency (such as the public utilities commission) procures wholesale generation to supply POLR load. The manner in which such generation is procured, the terms and conditions of the power sale/purchase agreement, and the tariff structure through which such generation is sold to POLR customers are subject to state jurisdiction.

Section 8
Conclusions

The design of New England's wholesale electricity markets has improved significantly during the past several years. FERC's approval of ASM II and the FCM Settlement Agreement made 2006 a landmark year for the region's wholesale electricity markets. These approvals make it possible for the ISO to focus its efforts on creating and implementing the FCM. Developing this market and integrating it successfully with the electric energy markets and Ancillary Services Market will require considerable effort spanning several years.