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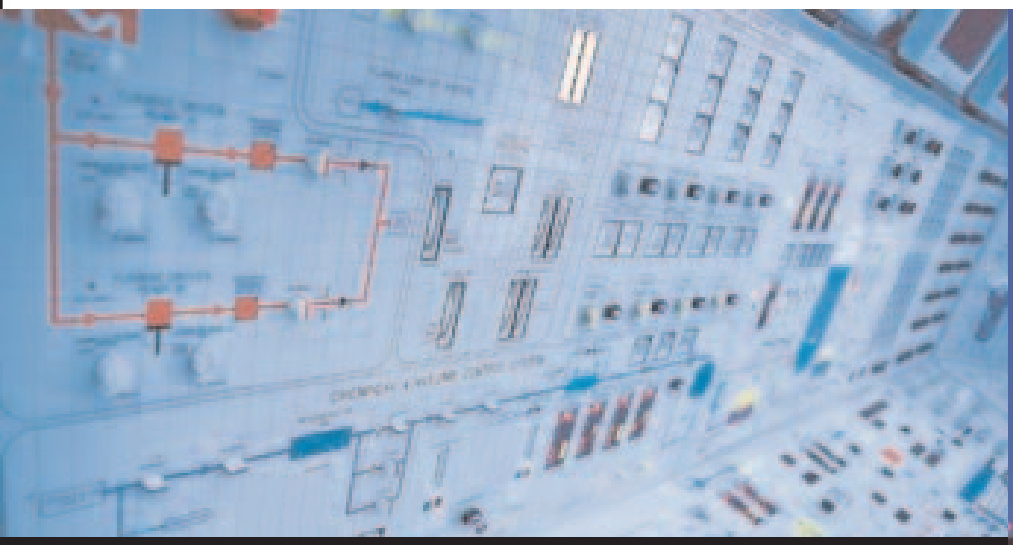

WHOLESALE MARKETS PLAN

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ISO New England Inc.

2005 WHOLESALE MARKETS PLAN

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Fall 2004

1. Introduction

On March 1, 2003, ISO New England Inc. (the ISO) implemented Standard Market Design (SMD), a major redesign of the wholesale electricity markets in New England. David Patton, Ph.D., the Independent Market Advisor to the ISO, and Robert Ethier, Ph.D., the ISO's Director of Market Monitoring, reviewed the implementation of SMD and found it successful overall. Their analysis and experience to date indicate the wholesale market design can be improved in a number of ways. The 2005 Wholesale Markets Plan continues the work outlined in last year's Wholesale Markets Plan. It also reflects many of Dr. Patton's and Dr. Ethier's suggestions for market improvements, as well as suggestions from the New England Power Pool (NEPOOL) stakeholders, the New England Conference of Public Utilities Commissioners (NECPUC), customer forums, and guidance from the Federal Energy Regulatory Commission (FERC).

The 2005 Wholesale Markets Plan (the Plan) details the ISO's plans to substantially improve the current capacity market, to create wholesale markets for ancillary services, to provide the infrastructure for direct participation by demand in the energy and ancillary services markets, to reduce seams with New York in the energy and capacity markets, to improve the integration of operating decisions and market pricing, and to implement the recommendations of the Cold Snap Task Force. It is quite likely that the projects initiated in any given year will have a lifecycle that is greater than one year. The development schedules of projects having a lifecycle of longer than one year are reflected in the planned implementation dates in the Project Release Schedule (Table 1, page 8).

The Plan complements the 2004 Regional Transmission Expansion Plan (RTEP04) and provides for an integrated planning approach. RTEP04 identifies the need for new transmission and generation investment to assure the long-term power system reliability of New England, including the region's major load pockets. Recognizing that the current markets are not yet complete and do not provide the full set of market signals to induce investment in these constrained areas, the Plan includes the development and implementation of locational capacity and ancillary services markets. These markets are intended to produce prices that signal the value of transmission, capacity, and reserve resources located within constrained areas.

2. Executive Summary

Last year's Wholesale Markets Plan outlined two major initiatives for 2003 and 2004: the Forward Reserves market and the Locational Installed Capacity market (Locational ICAP). The Forward Reserves project was implemented on schedule in December 2003. The implementation of the Locational ICAP market has been delayed until January 1, 2006 pursuant to a FERC order setting several aspects of the market design for hearing.

The market enhancements planned for 2005 are proceeding on schedule. These projects include Ancillary Services Markets (formerly called Co-Optimized Reserves), Virtual Regional Dispatch with New York, and Special Case Nodal Pricing for load. The Forward Market for Capacity in last year's plan was part of a joint project with the New York ISO and PJM Interconnection. Since then, each region has focused on the development of its own capacity market, and the Forward Market for Capacity has been deferred at least until the regional capacity issues are addressed.

A well-functioning capacity market is an important component of addressing resource adequacy in New England. However, further work is necessary to define resource adequacy and to identify the appropriate path for addressing emerging resource adequacy issues. The ISO will be working with stakeholders throughout the region to develop a process for addressing resource adequacy issues.

New projects included in the 2005 Plan include design changes to better integrate operational decisions and market pricing, the development of a Day-Ahead Load Response Program, and the implementation of recommendations from the Cold Snap Task Force. Other smaller projects are not currently detailed in the Plan, such as the creation of price nodes for external ties. The ISO will ensure that these smaller projects and others that materialize over the duration of the Plan are appropriately prioritized and planned through the stakeholder process. The Plan also marks the beginning of a research and development effort aimed at long-term market improvements. Projects in the research phase include increased demand participation in markets, Financial Transmission Rights options, marginal loss hedging, development of a market simulator to test feasibility of market designs, and review of a mixed-integer-programming engine to improve the optimization of the day-ahead unit commitment.

Table 1 on page 8 summarizes the 2005 Wholesale Markets Plan projects and implementation dates.

2.1 Market Design Overview

The market design enhancements included in the Plan continue to improve New England's wholesale markets by efficiently pricing the products and services required to reliably operate the power system, thereby enabling participants to make efficient short-term consumption and production decisions and efficient long-run investment decisions. Since the wholesale electricity markets (separate, but related markets for energy, capacity, and ancillary services) are complex and interdependent, care must be taken to ensure the markets work properly together without gaps or duplication. The design of the Locational ICAP and Ancillary Services Markets projects described in the Plan includes a detailed review of the interaction among energy, capacity, and ancillary services to ensure that they complement each other.

The projects in the Plan will improve the pricing of products and services in each of the markets. The improvements in the Locational ICAP market include the introduction of a sloped demand curve and the introduction of locational requirements to enable the capacity market to more appropriately value the capacity product. The Ancillary Services Markets projects will provide incentives for resource owners to make available the flexible quick-start resources that are needed for reliable system operation. The proposed changes to the regulation market will pay resources for the service they provide rather than for the amount of capacity provided, as in the current regulation market. The Plan also includes projects to allow demand to directly participate in the energy and ancillary services markets, thereby improving the efficiency of those markets.

The completion of the projects in the Plan will create a more complete set of wholesale electric markets that efficiently price the products and services needed for reliable short-term operation of the power system and long-term resource adequacy.

2.2 Market Design Improvements

The Plan will improve the existing wholesale electricity markets and addresses six important areas:

- Improving the capacity market by adding locational requirements and a demand curve;
- Creating locational markets for operating reserves;
- Increasing demand-side participation in the energy market and ancillary services markets;
- Improving integration of operating decisions and market pricing;

- Reducing market seams with New York in both the energy and capacity markets; and

- Implementing the recommendations of the Cold Snap Task Force.

Each of these areas is briefly described below. Later sections provide a more detailed discussion of each project and its market-design rationale.

2.2.1 Capacity Market Enhancements

Both the application of economic theory to electricity markets and the ISO's experience operating wholesale electricity markets in New England since 1999 show that, in large part because of the offer caps on energy, the energy and ancillary services markets alone are not likely to generate sufficient revenues to support long-term investment. New England's experience in this regard is consistent with that of the New York and PJM markets. Consequently, the electricity markets in the Northeast have all developed capacity markets to address this problem. The existing capacity market design in New England requires improvement in three areas: better definition of the product, the structure of the demand curve, and recognition of the locational value of capacity.

The ISO has filed a Locational ICAP proposal with the FERC that addresses the demand curve and recognizes transmission constraints and load pockets in the setting of capacity obligations. Section 4 further details the capacity market enhancements.

2.2.2 Ancillary Services Markets

Because electric supply and demand must be balanced at every moment, ancillary services (operating reserves and regulation) are crucial to maintaining the reliability of the bulk electric grid. Prior to December 2003, there was no market that explicitly priced the value of resources that could start up quickly and provide energy for a short period of time. As a first step in addressing this problem, the ISO implemented a regional forward reserves market in December 2003.

The Plan builds upon the Forward Reserves project and includes other significant improvements in the Ancillary Services Markets projects. The Ancillary Services Markets projects include:

- The incorporation of reserve requirements into the real-time dispatch providing for the joint optimization of energy and reserves in real time;

- The implementation of a real-time clearing price for reserves based on an improved shortage pricing mechanism and the opportunity cost of providing reserves;
- The implementation of a locational component in the forward reserves market;
- Providing the infrastructure to support the direct participation of demand in the energy and reserves markets; and
- The redesign of the regulation market.

The Ancillary Services Markets projects are further discussed in Section 5. The hardware, software, and market design that will be put in place as part of the Ancillary Services Markets projects are required to enable the improved integration of operating decisions and market pricing discussed in Section 2.2.5.

2.2.3 Demand-Side Participation in Energy and Ancillary Services Markets

Without demand-side participation, wholesale electricity markets cannot efficiently price energy, particularly during shortage conditions when demand would otherwise exceed the available supply. The lack of demand-side participation also exacerbates market-power concerns and contributes to the need for an offer cap in the energy market. To lay the groundwork for further demand participation in the markets, the Plan includes the following projects:

- Improve the ISO's dispatch software to enable dispatchable loads to participate in the energy and ancillary services markets;
- Introduce Special Case Nodal Pricing to allow qualified market participants to purchase electricity at a nodal price;
- Work with market participants, state regulators, and state legislatures to create retail rate structures that encourage consumers to be more responsive to price and to improve the linkage between the wholesale and retail markets;
- Increase participation in the ISO's real-time load response programs; and
- Implement a Day-Ahead Load Response Program.

Section 6 provides further details on these projects.

2.2.4 Virtual Regional Dispatch

The Plan continues to address market seams through the development of Virtual Regional Dispatch with the New York ISO. The ISO believes that Virtual Regional Dispatch is the best alternative absent a single dispatch approach. Under Virtual Regional Dispatch, the ISOs plan to synchronize system operations between New York and New England by enabling the ISOs to periodically adjust energy exchanges based on market price differences. This practice, recommended by Dr. David Patton, the Independent Market Advisor to the New York and New England ISOs, and approved by the FERC in the recent New England RTO Order, should improve market efficiency by capturing unrealized arbitrage opportunities. Implementation is subject to further analysis and prototyping to validate that reliability and overall market efficiency is not compromised in the two regions. Section 7 provides further details on this topic.

2.2.5 Improved Integration of Operating Decisions and Market Pricing

Since the inception of competitive wholesale electricity markets in New England, the market rules and manuals have been improved to more accurately reflect the requirements of power system operation in the pricing and settlement of the New England markets. Further improvements are needed to ensure that operator actions are appropriately reflected in market prices. Power system operation is, by its nature, a dynamic process. No two days of operation are ever the same, and system operators are faced with myriad transmission, generation, and system load configurations that must be managed in real time. The large set of possible operating conditions makes it difficult to capture and model all possible operating scenarios within the context of general market rules and the practical limits of market analysis and pricing software.

Over the next year, the ISO will work with market participants to define rules or methods that will allow necessary system operator actions, such as out-of-merit dispatch in import-constrained areas and the need for dynamic reserve requirements in unusual situations, to be more appropriately reflected in the various market-clearing prices. Section 8 provides further details on this topic.

2.2.6 Recommendations from the Cold Snap Task Force

As outlined in RTEP04, New England's dependence on gas-fired generation poses a risk to ensuring adequate generating unit availability during the winter period. This was experienced during the January 2004 Cold Snap. As a result of this event, a Cold Snap Task Force was created that included the ISO, market participants, and regulators. This Task Force has developed several short-term actions to

prepare for the winter of 2004/2005. The short-term recommendations call for the establishment of a new operating procedure for cold snap periods. It would trigger the elimination or cancellation of economic outages, switching to alternative fuels for dual-fueled units, and modification of unit commitment processes to enhance coordination between the electric and gas market timelines. The modification entails moving the deadline for submitting bids and offers to the day-ahead market, currently 12:00 noon, to 9:00 a.m. under certain conditions. An earlier deadline for bid submission enables the ISO to issue commitment schedules to the required number of gas-fired generators prior to the deadline for daily nominations in the day-ahead natural gas markets. The Task Force will continue to work toward making long-term recommendations. The ISO expects that it will work towards the long-term recommendations in the 2005-2006 timeframe. The ISO also believes that the Locational ICAP market (discussed in Section 4.1) will partly address the issue of unit availability during shortage periods.

3. Wholesale Markets Plan Implementation Approach and Schedule

To allow for effective planning, optimal utilization of information-technology resources, training, and thorough testing of changes to the markets (including external market trials with participants, if applicable), the ISO has implemented a software-release approach. Changes to the markets are packaged into discrete software releases. This benefits market participants by providing advance notice of market changes, enabling them to prepare their business strategies and market operations to accommodate these changes by minimizing costs, and reducing the risks associated with frequent releases.

A critical factor in meeting the release schedules in the Plan is to reach consensus on market design detail with sufficient lead-time to permit software development to proceed. If consensus cannot be reached, approvals cannot be obtained, or if changes to a design occur close to the release date, market projects may fail to be completed as scheduled. To obtain the benefits associated with the development of a multi-year plan, all stakeholders will need to work to reach general agreement on design specifics well in advance of the scheduled release date.

Table 1 summarizes the project release schedule for the six areas of improvement listed in Section 2.2 of the Plan. The Cold Snap Task Force recommendations will be addressed through both a short-term project and a long-term project. Demand-side participation in the energy and ancillary services markets is included in several different projects.

TABLE 1: PROJECT RELEASE SCHEDULE[1]

PROJECT	PROJECT STATUS	MARKET DESIGN FINALIZED	PLANNED IMPLEMENTATION DATE	INTERNAL RESOURCE REQUIREMENT
Locational ICAP	Hearing set by the FERC on several issues	Will be confirmed based on FERC hearings – current planned date is June 2005	January 1, 2006	Medium
Ancillary Services Markets *(previously called Co-optimized Reserves)* > Locational forward reserves > Joint optimization of energy and reserves in real-time > Demand participation in real-time markets and ancillary services markets > Regulation market redesign	Design effort underway	December 2004	October 2005	High
Virtual Regional Dispatch	Pilot project design under review	Pilot Project Design by September 2004	Pilot project in Q1 2005; Full Implementation TBD based on results of pilot project	Medium
Special Case Nodal Pricing *(previously called Changes to Zonal Pricing)*	Pending FERC approval	Complete	October 2005 (linked to Ancillary Services Markets)	Medium
Day-Ahead Load Response Program	Pending FERC approval	Complete	October 2005 (linked to Ancillary Services Markets)	Medium
Short-term Cold Snap Task Force recommendations: Modification of day-ahead commitment process to improve electric-gas market coordination	Pending FERC approval	Complete	December 2004	Medium
Long-term Cold Snap Task Force recommendations	Partly addressed in conjunction with Locational ICAP implementation, other changes to be defined in the context of resource adequacy working group discussions	Subject to working group discussions	Subject to working group discussions	Subject to working group discussions
Improved integration of operating decisions and market pricing	Review of out-of-merit dispatch and power system interface limits	Please refer to Section 8	Please refer to Section 8	Please refer to Section 8

[1]The Plan, including implementation dates, is described as of September 2004. Specific elements may change as a result of stakeholder process, FERC approvals, practices in neighboring regions and other factors such as the outcome of the Locational ICAP hearing. The timeframe presented for each enhancement is tentative and is based on current estimates of the scope of work and level of effort required. Successful completion of the projects included in each release requires that the ISO and its market participants agree on the market design for each enhancement with sufficient lead-time to allow software development to proceed in support of the release schedule. The market design schedule reflects the date by which this agreement must be reached to meet this schedule and the earliest date at which a firm project plan (scope, schedule, and budget) will be provided.

4. Capacity Market Enhancements

The ideal electricity marketplace would consist of energy and reserves products, and producers would earn a return from the marketplace by supplying these products. Suppliers would be disciplined by price-responsive demand; prices would be determined by the willingness of suppliers to sell and buyers to buy energy and reserves. In this ideal situation, prices would never be "too high," since individual buyers would curtail their demand at price levels where they were no longer willing to pay for the product. Price would be set at the value of lost load as determined by consumers in the market.

Ideal market conditions do not exist. The ISO has no way to identify and curtail only those customers who express an unwillingness to pay a particular price, end-use customers have been shielded from real-time prices by a variety of supply arrangements and regulatory requirements, and customer demand has proven to be extremely inelastic. In such an environment, which effectively has a vertical demand curve, prices during shortage conditions are susceptible to the exercise of market power. This makes it difficult to correctly price energy and reserves in shortage conditions. In response to this problem, the FERC has instituted energy offer caps. While these caps limit the exercise of market power by suppliers, they also disrupt the natural price-rationing function of markets, and they result in inadequate price signals for investment. In the Northeast electricity markets, this problem has been addressed through the implementation of capacity markets.

With the implementation of SMD, the ISO adopted the capacity market design then operating in the New York marketplace. The New York design was chosen because that design was considered successful and to provide the New York and New England marketplaces with a common capacity product. Upon initial implementation, the New England ICAP did not include the locational requirements included in the New York design. Through a series of orders addressing contracts for must-run resources and other issues, the FERC directed the ISO to implement a locational capacity market by June 1, 2004.

RTEP04 describes the transmission and resource needs of the region over the next several years. It also discusses the need for new planning methodologies and tools to enhance system reliability and to improve consistency with the overall market design. Many of the problems described in RTEP04 are local in nature. The efforts discussed here to provide a locational capacity market complement RTEP04 by providing a market mechanism to address the identified reliability concerns.

4.1 The Locational Installed Capacity Filing

On March 1, 2004, the ISO filed a Locational ICAP design with the FERC that included a sloped demand curve to address ICAP price volatility, a locational clearing process to appropriately price capacity on a locational basis, and a capacity transfer rights mechanism to allow for non-uniform allocations of the ability to import capacity into or export it from a region. The FERC approved the overarching design of the ISO's Locational ICAP proposal (the use of a downward-sloped demand curve and pricing within constrained regions), but set certain issues for hearing, including the specific parameters of the demand curve, the method of calculating capacity transfer limits, and the allocation of capacity transfer rights. In addition, the FERC directed the ISO to address whether the creation of a separate ICAP region for Southwest Connecticut is warranted. On July 2, 2004, the ISO submitted a filing providing evidence to support the creation of a Southwest Connecticut ICAP region. In the hearing process, the ISO is submitting testimony regarding demand curve parameters, capacity transfer limits, and capacity transfer rights allocations. The ISO's testimony also addresses the definition of the ICAP product and the design parameters for ensuring the availability of capacity.

5. Ancillary Services Markets

The Ancillary Services Markets projects will provide locational price signals for quick-start units that provide operating flexibility. In addition to the implementation of a locational forward reserve market and the joint optimization of energy and reserves in real time, the Ancillary Services Markets project will include market-design changes that will enable dispatchable loads to participate in the real-time energy and ancillary services markets and improve the efficiency of the regulation market.

5.1 Forward Reserves Market

The current forward reserves market is not locational and does not allow for bilateral trading or demand-resource participation. These features will be added to the current forward reserves market in the Ancillary Services Markets project.

More specifically, the forward reserves market requirements and clearing process will be modified to add a locational component. This component will reflect the forecasted operational requirements for commitment and dispatch to meet the second-contingency requirements for defined areas (so-called "reserve zones") of the power system. These requirements will be observed in both forward-market clearing and real-time dispatch.

The forward reserves market will be modified to allow participants to submit "portfolio" bids for evaluation and clearing in the market and to trade these obligations via bilateral arrangements. All obligations will have to be converted to physical resources by the bidding deadline for the day-ahead market.

Finally, the forward reserves market will be modified to allow demand resources that meet the technical requirements to participate in the market.

5.2 Real-Time Hourly Reserves Pricing

The dispatch algorithm currently used in the energy market does not recognize the locational reserve requirements to which the ISO must adhere when operating the system. If the energy dispatch alone does not provide sufficient reserves, system operators have to manually dispatch the system to provide those reserves. The Ancillary Services Markets project will include the locational reserve constraints in the energy dispatch, thereby jointly optimizing energy and reserves. An hourly clearing price for reserves will be created when there is an opportunity cost for providing reserves or when there is a reserve shortage. It is anticipated that fast-start resources, when economic for energy or reserves or when needed to manage transmission constraints, will continue to be committed and dispatched by the real-time dispatch software.

5.3 Demand-Side Participation in the Reserves Markets

One of the ISO's goals is to enable full demand response in the wholesale markets. Once integrated into real-time operations, demand resources have the potential to offer reserve services. In many cases, demand is able to respond rapidly to real-time market signals and could earn reserve revenues without foregoing electric service. Thus, not only could demand response make these markets more competitive, but reserve markets may also provide significant incentives to develop demand response resources. Accordingly, the software infrastructure needed to support the ability of demand-side resources to participate in the reserves market will be implemented as part of the Ancillary Services Markets project.

5.4 Regulation Market Redesign

The existing regulation market will be improved by adding two key features of the regulation market design used in New England's interim market, the determination of the regulation clearing price in real time and the compensation of resources providing regulation based on their response to regulation signals sent by the ISO (commonly known as "mileage" payments).

The regulation market will continue to be a real-time market only, and the quantity will be "MW of Regulation available in 5 minutes." Regulation will not be cleared in the day-ahead market. However, as part of the project, the ISO will institute a process whereby the Resource Adequacy Assessment will review the need to commit additional resources to satisfy the real-time regulation requirements.

The regulation clearing price will be set to the offer price of the most expensive resource selected to provide regulation. Generators providing regulation service will earn service payments based on the regulation clearing price and their responses to the regulation signals. This is more efficient than the current system as it more accurately prices the service actually provided by the resource owners. A generating resource deemed to be operating out of merit on an hourly basis to provide regulation will receive an additional ex-post opportunity cost payment.

6. Demand-Side Participation in Energy and Ancillary Services Markets

6.1 Wholesale-Retail Market Linkage Issues

Consumers' ability to capture the benefits of competitive electricity markets depends (1) on ensuring consistency between the design and administration of the competitive wholesale market, and (2) on the retail markets and regulatory frameworks designed to provide end-use customers with reliable, stable, and reasonably priced electricity service. Inconsistencies between wholesale and retail market policies could result in market inefficiencies. In New England, for example, wholesale markets are designed to reflect geographical and temporal differences in power costs, which provides economic incentives for optimal investment and demand response levels in the right places and at the right times. However, these efforts could be neutralized by retail rate designs, which are 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 services[2] could be modified to achieve better alignment with the wholesale market structure, which would improve the efficiency of the overall electricity market. For example, greater use of dynamic pricing (retail prices that vary in real time directly with wholesale spot-market energy prices) applied to price-responsive customers would be the most direct way to increase the responsiveness of demand to wholesale spot-market energy prices, particularly during periods of capacity shortages and price spikes. The ISO plans to work with NECPUC and market participants in select state rulemaking and legislative proceedings to address the manner in which Provider of Last Resort service is priced and procured.

6.2 Special Case Nodal Pricing

In conjunction with the Ancillary Services Markets projects (described in Section 5), the ISO plans to implement Special Case Nodal Pricing, which would permit qualifying customers to settle at nodal prices. Individual end-use metered customers that are at least five megawatts in size connect to a single node, and comply with certain technical and administrative criteria would be eligible to participate in Special Case Nodal Pricing. Eligible customers could choose a non-dispatchable or a dispatchable option. Customers opting for dispatchable status would be considered ICAP resources and eligible to receive ICAP credit. They would be required to be available for scheduling and dispatch during the operating day if the ISO were to declare an emergency condition – a specific action in OP-4. Special Case Nodal Pricing would increase demand resources in the market, and it would better integrate demand response directly into the market design without requiring non-participants to subsidize program participants. If end-use customers participating in Special Case Nodal Pricing dispatch off at high prices, they would contribute to the demand response necessary for efficient markets.

6.3 Day-Ahead Load Response Program

The Day-Ahead Load Response Program is being developed in response to a FERC order. The program will be designed for demand resources that can offer load reductions concurrent with the day-ahead wholesale electricity market. The Day-Ahead Load Response Program contributes to greater market efficiency by allowing the demand resource to specify the wholesale electricity price at which it is willing to curtail load. The demand resource has greater control over its load reduction

[2] 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 (POLR) 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.

because it knows a day in advance when and for how long its load reduction will be scheduled. Under the present design, the demand resource's load reduction offer is accepted when the day-ahead market price is equal to or higher than the price offered by the demand resource.

6.4 Integration of Demand-Side Resources into the Real-Time Dispatch

Demand resources help balance supply and demand, and participation by demand is necessary for the wholesale market to efficiently price energy and reserves without the use of administrative pricing rules. However, ensuring efficient clearing prices requires market rules and information technology infrastructure that enable demand resources to bid into the market. To facilitate direct participation by demand in real-time markets, the ISO will modify the real-time dispatch to enable real-time dispatchable loads to set price. This task will be part of the Ancillary Services Market projects since both efforts require similar software modifications. Subject to necessary regulatory and legislative changes, this project would enable dispatchable loads to fully participate in the market.

7. Virtual Regional Dispatch

The interchange of electricity across external interfaces is the most fundamental seams issue between the New York and New England control areas. To reduce the impediments to trade across external interfaces, the New York and New England ISOs are proposing Virtual Regional Dispatch, the exchange of energy between New York and New England based upon market-price differentials.

An efficient market attains price convergence at uncongested interfaces. Market participants can quickly arbitrage large price differences, ensuring that energy flows from the lower-priced area to the higher-priced area, and prices converge. However, at the present time, prices at the New York and New England border do not converge, and the efficiency of both markets suffers. The markets could potentially realize savings by mitigating this inefficiency.

This market inefficiency is reflected in persistent price differences at uncongested interfaces and counterintuitive flows in both directions. As Dr. David Patton reported in 2002, the two markets have not been able to attain consistent price convergence at external interfaces. Transactions respond sluggishly to large price differentials, and net flows often run counter to the prices in the two regions, i.e., higher-priced energy sometimes flows toward the lower-priced region.

Virtual Regional Dispatch fully utilizes the load bids and supply offers from New York and New England to meet the combined load of the two markets more efficiently than is currently possible using physical transactions between the regions.

Under Virtual Regional Dispatch, the physical interchange between the New York and New England ISOs will be automatically adjusted based on the relative prices in each market (i.e., the marginal cost of generation) to maximize the utilization of the interface and facilitate price convergence between the markets. The objective is to allow the control areas to jointly realize the benefits of a larger market, while maintaining separate dispatches.

Virtual Regional Dispatch is an important component of the market design since both New York and New England have implemented shortage pricing. Shortage pricing should occur only in the presence of true shortages, not when apparent shortages occur that can be partly attributed to inefficient use of the interface. Virtual Regional Dispatch will ensure this is the case by making maximum use of the interface.

7.1 Virtual Regional Dispatch Pilot Program

Implementation of a Virtual Regional Dispatch is subject to a technical feasibility analysis and prototyping to ensure that it enhances overall market efficiency without diminishing reliability. To this end, a Virtual Regional Dispatch pilot program is targeted for the first quarter of 2005. The purpose of the pilot program is to provide insight into the requirements of Virtual Regional Dispatch operation, its feasibility and its impact on the market. The pilot program will help identify issues associated with intra-hour short-term exchanges of energy in a wholesale market environment and evaluate the need for additional pre-development or pre-deployment testing. The ISO expects that, subject to FERC approval, initial pilot testing will be conducted in the first quarter of 2005.

8. Improved Integration of Operating Decisions and Market Pricing

The present market rules and design describe the pricing methods used under normal power system conditions as well as under some abnormal conditions (i.e., system-wide reserve shortage conditions). In some instances, however, the system operators are forced to take actions that are not explicitly modeled in dispatch or price-setting algorithms. The ISO recognizes the importance of better integration of operating decisions and market rules and will continue to work with the market participants on improving the market design and market rules. In this regard, the current plan includes the review of out-of-merit commitment and power system interface limits. The ISO expects that each of these reviews will result in a series of initiatives. Each of these initiatives will be staffed and treated as a smaller project, with an accompanying scope, budget, and schedule.

8.1 Out-of-Merit Commitment

Out-of-merit commitments occur when the power system reliability criteria cannot be satisfied with normal economic commitment and dispatch. In New England this problem is significant because of a weak transmission system and a lack of flexible generating resources within load pockets. Part of the Ancillary Services Markets project, for example, the modeling of locational constraints in real-time dispatch, will allow for the inclusion of some out-of-merit commitment costs in reserve pricing. However, fully including out-of-merit commitment and dispatch in energy pricing is an industrywide problem that has not yet been resolved. The ISO places a high priority on this issue and has taken steps to simulate and monitor the frequency and magnitude of out-of-merit commitment in the day-ahead and real-time markets. The ISO will work with the market participants to continue to improve market pricing under such circumstances.

8.2 Review of Power System Interface/Proxy Limit Calculations and Assumptions

A key component of locational pricing and transmission-constraint control in the wholesale markets structure is the set of transmission limits and assumptions that are utilized in the power system dispatch. The ISO will review and modify, as appropriate, the assumptions, processes and procedures associated with the calculation of these interface limits. The ISO has already initiated a quality process review with the participants on the transmission ratings. The ISO expects these steps to improve integration of operating decisions and market pricing.

9. Research and Development

Several emerging areas of technology might offer benefits to the New England wholesale electricity markets. Prior to implementing any of these new methodologies, it is prudent for the ISO to conduct research into their applicability to the New England marketplace. Beginning with this year's Plan, the ISO will provide information about such areas of research. The list of topics in this section is subject to change based on the ISO's analysis and budget constraints.

9.1 Increased Demand Participation in Markets

As market requirements tend to be based on known generation technologies, such requirements could have the unintended consequence of undermining the development of demand response resources. For example, individual demand response resources are relatively small; the use of sophisticated metering and communication technology typically required of large generators to enable system operators to monitor system status and to communicate dispatch instructions may not be cost effective for demand response. Thus, requiring demand resources to meet the same technology requirements as generators could effectively prohibit the participation of demand resources in forward reserves and ancillary services markets.

To address this potential barrier, the ISO will be working with staff from the National Laboratories funded by the U.S. Department of Energy to develop and implement a pilot program to determine the ability of demand resources to meet system operational requirements and to investigate more cost-effective means by which such resources could participate in the market without sacrificing system reliability. The results of this pilot program would be the development of rules, business procedures, and infrastructure protocols that will enable effective and efficient participation of demand resources in markets.

9.2 Financial Transmission Rights Options

As the term of the Financial Transmission Rights (FTRs) gets longer, the obligation-style FTR exposes the holder to the risk that changes in system configuration at some point in the future could render it worthless or, worse still, require the holder to make payments. FTR options help manage this risk. These options are essentially unidirectional FTRs that grant the holder the right to congestion revenues in a particular direction. The ISO is investigating the impact of including these options in the set of fundable FTRs and is currently assessing software tools.

In addition, the ISO is investigating the use of FTR options as a means of providing tradable property rights to transmission facilities that are eligible for a Qualified Upgrade Award. Currently, Qualified Upgrade Awards receive a portion of the FTR auction revenues, but there is no property right associated with them. If FTR options prove feasible, they should provide a long-term property right to the Qualified Upgrade Awards, thereby limiting the risk of such investments and perhaps enhancing the marketability of merchant transmission investments more broadly.

9.3 Hedging Marginal Losses

In the current implementation of SMD, the Locational Marginal Price (LMP) includes not only energy and congestion components, but also a marginal loss component. The introduction of an LMP loss component makes it difficult for market participants to hedge against the price difference using FTRs, since the FTR is settled only on the difference of the congestion components. The ISO will research potential approaches to provide a means for hedging against system losses.

9.4 Market Simulator

The ISO plans to begin working with industry experts on the development of a market simulation program for the New England region. The ISO's efforts will be focused on the simulation of bidding strategies and market behavior analysis. With the help of these advanced simulation technologies, the market simulator could provide the ISO with a better means to analyze the effects of new market rules and bidding behavior.

9.5 Unit Commitment Enhancements

Implementing improved optimization methods in power system scheduling, dispatch, and market clearing can save millions of dollars in production costs. The technology and methodologies associated with optimization algorithms are constantly evolving.

Due to the size and complexity of the unit-commitment problem and because of the economic benefits that could result from an improved solution to it, the ISO will work closely with industry experts in improving the efficiency of its unit commitment through the use of mixed-integer-programming based algorithms. These algorithms provide for direct incorporation of decision variables (like yes/no) in the optimization, and the optimal solution will contain integer and continuous

variables. Until recently, these algorithms were considered largely theoretical due to the combinatorial nature of the solution process and very large dimensions of the problem. Recent industry advances in modeling and optimization tools have made it possible to use mixed-integer-programming engines in production, and other markets are exploring this technology.

The ISO's work will focus on simulation of the mixed-integer-programming based algorithms using third-party products and their applicability to the New England markets and the modeling of complicated problems, such as combined-cycle units and variable ramp rates.

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