UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security	**)**	**Docket No. AD05-13-000**
Constrained Economic Dispatch	**)**	

Study and Recommendations Regarding Security Constrained Economic Dispatch (SCED) in the Northeast

by

The Joint Board on Economic Dispatch for the Northeast Region

May 24, 2006

I. Overview

The Northeast Joint Board is one of four joint boards designated by the Commission under EPAct2005, Section 1298 Economic Dispatch. The members of the Northeast Joint Board are:

> Commissioner Nora Mead Brownell, Federal Energy Regulatory Commission, Chair of the Joint Board
> Commissioner Paul G. Afonso, Massachusetts Department of Telecommunications and Energy, Vice Chair of the Joint Board
> Chairman William M. Flynn, New York State Public Service Commission, Vice Chair of the Joint Board
> Commissioner Jack R. Goldberg, Connecticut Department of Public Utility Control
> Chairman Kurt Adams, Maine Public Utilities Commission
> Chairman Thomas B. Getz, New Hampshire Public Utilities Commission
> Chairman Elia Germani, Rhode Island Public Utilities Commission
> Chairman James Volz, Vermont Public Service Board

The Northeast Joint Board met in public session on November 29, 2005 in Boston Massachusetts and on February 13, 2006 in Washington, D.C.

As the Commission noted in the initial order convening the joint boards:

> Each joint board is authorized: (1)"to consider issues relevant to what constitutes '*security constrained economic dispatch*'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

In the following sections, this report provides a description of the basic concept of Security Constrained Economic Dispatch (SCED); describes background on the variations in dispatch procedures in the Northeast, and gives a summary of the issues raised and considered by the board, together with any recommendations made to address these issues. The principal sources for these sections are presentations to the board and written comments submitted, discussions among the Joint Board members, the DOE report under EPAct 2005, Section 1234 and the responses to the DOE survey of economic dispatch under Section 1234.

II. Security Constrained Economic Dispatch: The Basics in the Northeast Region

For purposes of the joint boards' studies, the FERC adopted the following definition of security constrained economic dispatch: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[1] This definition describes the basic way all utilities or ISOs/RTOs dispatch resources to meet electricity load. The basics of SCED are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand, demand varies greatly over the course of a day, week, and seasons, the costs of generation from different types of units vary greatly, and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. SCED is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

SCED occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, SCED decides which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast and transmission constraints. SCED uses either cost-based or bid-based offers to select the most economic generator mix, considering transmission constraints. In selecting the most economic generators to commit, SCED also takes into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, minimum time a generator must run once it is started, and environmental restrictions.

In addition, forecasted conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive

---

[1] September 30, 2005 order at P14. These operations are normally automated and carried out by computer software; however, the operations are monitored by transmission engineers who can override the software when necessary.

generators may have to replace cheaper units.[2] Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, SCED decides in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment and SCED must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure flows stay within reliability limits and voltage within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes.

The manner in which transmission and operational limitations of generators have been represented in unit commitment and economic dispatch software has not been uniform across the industry. For example, some unit commitment software packages might represent the entire transmission network in detail while others might only represent selected transmission constraints to make the problem easier to solve. Similarly, the representation of unit operational constraints and in some cases even the network model might vary in economic dispatch software.

The economic dispatch problem is generally considered to be a mathematically simpler problem to solve, although recent advances (e.g. the use of mixed-integer-programming (MIP) for unit commitment) have advanced the available technology to the point where many earlier limitations on problem size have been eliminated. Advances in hardware and software now make it technologically feasible to undertake security constrained economic dispatch over large regions.

In addition to differences in models used in economic dispatch software, a major factor that can impact the benefits of economic dispatch is whether or not all available resources are considered. In non-organized markets this may not always be possible due to various reasons including limitations in open access transmission tariffs based on Order 888.

---

[2] If the more expensive units are not allowed to set the market prices, these units are referred to as "out of merit" and their above market costs must be recovered through uplift.

III. Economic Dispatch in the Northeast

Security Constrained Economic Dispatch (SCED) in the northeast is performed primarily by two entities – ISO New England (ISONE), which has been designated as a Regional Transmission Organization (RTO) and the New York ISO (NYISO). Both entities operate day-ahead and real-time energy markets that constitute the commitment and dispatch components of SCED described in the last section. There is a long history of SCED is the Northeast under these entities and prior to this under the NY Power Pool and NEPOOL.

There is much in common between the two regions in how they perform SCED. Both NYISO and ISO-NE have consolidated control areas and perform the dispatch function centrally. SCED has been performed in both regions since the 1970s under the predecessor power pools and continues with enhancements under the markets that have been in operation since 1999. They both incorporate transmission constraints and unit operational constraints within the dispatch and commitment software. They both include all available resources without regard to ownership. Both regions have significant load pockets, e.g., New York City, Long Island, Boston and Southwest Connecticut that require higher cost local generation. Both regions have had limitations on reflecting the full spectrum of physical constraints in their software that has resulted in uplifts, i.e., costs that are not included in the market price and are administratively allocated to participants. Currently, this appears to be a bigger problem in New England.

A. NYISO and NYPP

The NYPP was formed in response to the Northeastern blackout of 1965. By 1977 it had implemented a form of SCED that dispatched all of the utility-owned generation in New York State based not on market-driven bidding, but on regulated generator costs. The NYPP SCED did not incorporate non-utility generation. Nevertheless, it produced substantial savings by dispatching generation on a least-cost basis and by taking advantage of supply and load diversity across the pool. The resulting savings were split among the NYPP's utility members and went to the ultimate benefit of ratepayers.

The NYPP SCED made it possible for energy transactions to be scheduled and priced more efficiently than was possible before 1977. Prior to the SCED, the NYPP could only facilitate bilateral transactions among its member utilities by acting as an intermediary. This was done through telephone calls and allowed transactions to be scheduled on, at best, an hourly basis. Under SCED, transaction scheduling and pricing was fully automated and took place every five minutes. In addition, the adoption of SCED allowed the NYPP to develop an "Interchange Evaluation" program, which evaluated energy transactions between neighboring control areas in the United States and Canada, including New England, the mid-Atlantic, Ontario and Quebec. This evaluation improved inter-control area energy deliveries in the Northeast and made out-of-state economic resources more readily available to the NYCA.

The adoption of SCED also permitted a more efficient allocation of Operating Reserves among NYPP members to satisfy total pool requirements. The NYPP estimated that SCED, and the various external transaction scheduling improvements that it made possible, was responsible for $281 million in savings in 1981, which would translate to approximately $600 million in 2005 dollars.

In the 1990s, the NYPP's members formed the NYISO. From its inception in 1999, the NYISO used a bid-based SCED that was open to all electricity resources in the NYCA, and to out-of-state suppliers selling into New York, that chose to participate in it. The NYISO SCED is a key part of the NYISO's market that uses a locational-based marginal pricing system ("LBMP") very similar to the locational marginal pricing (LMP) regimes that have evolved in the ISO New England, PJM Interconnection, and Midwest Independent System Operator regions.

The NYISO implemented major enhancements to its real-time dispatch and market software on February 1, 2005. It now has fully co-optimized day-ahead and real-time markets for energy, three different reserves products, and regulation that produce the lowest possible total cost for these products consistent with reliability constraints. The NYISO's new software platform includes a real-time unit commitment ("RTC") function that complements the NYISO's day-ahead security constrained unit commitment process using the superior information that becomes available closer to the actual real-time dispatch. RTC is capable of looking two and a half hours ahead and can commit "quick start" resources such as hydro units and certain gas turbines in fifteen minute increments in order to facilitate a more efficient co-optimized, least-cost SCED for energy ancillary services. The RTC is integrated with and uses the same software as the NYISO's real-time dispatching system, which helps them to work together to produce the best possible dispatch and price signals. There are nearly three hundred active market participants in the NYISO markets today. In 2005, the NYISO settled electricity transactions totaling approximately $10.7 billion and has cleared over $40 billion of wholesale transactions since its inception in 1999.

B. ISO-NE and NEPOOL

The New England Power Pool (NEPOOL) was formed in 1971 by the region's private and municipal utilities to foster cooperation and coordination among utilities in the six-state region. During the next three decades, NEPOOL created a regional power grid that now includes more than 350 separate generating plants and more than 8,000 miles of transmission lines.

ISO New England was created in 1997 in a region where 88 percent of the region's generation is unregulated, the most in the nation. Working closely with the NEPOOL, now a group of generators, utilities, marketers, public power companies and end users, ISO New England implemented wholesale markets in 1999. Today, more than 260 Market Participants complete in excess of $10 billion of wholesale electricity transactions annually, about a quarter of the power sold in the region (the remainder is sold through negotiated, long-term contracts).

ISO New England has enhanced these markets, notably in 2003, by adding features such as a Day-Ahead Market. In the five years following the opening of wholesale markets in 1999, New England's capacity has increased by 40 percent. Wholesale electricity prices in New England, adjusted for fuel costs, have declined by 5.7 percent since the first full year of market operations. Prices dropped by 11 percent during the four-year period from 2001-2004.

Security Constrained Economic Dispatch (SCED) is an essential component of the ISO-NE markets. It figures in the day-ahead unit commitment performed under the day-ahead market and in the real-time balancing market.

New England's Economic Dispatch is coordinated with the Economic Dispatch of neighboring control areas through hourly exports and imports of power. These exports and imports are generally scheduled by market participants responding to electricity prices in each control area, with participants seeking to buy power in the lower priced control area and sell in the higher priced control area. If the volume of transactions increases until either the prices at the source and delivery points are equal, or until the transfer limits are reached, than the dispatch is efficiently coordinated between the control areas. Because this efficient coordination does not regularly occur between New York and New England, the two control areas are investigating ways to improve the coordination. Possible solutions include the two ISO's explicitly coordinating interface flows and reducing the lead time required for participants to schedule flows across the interface between the regions.

IV. Observations and Issues

This section describes the issues considered by the Joint Board and identifies any recommendations in the record. Based on the discussion at the initial meeting, there appeared to be an overall consensus that economic dispatch and markets have created benefits for customers in the Northeast. There is a long history of economic dispatch in the region that was mentioned by many participants along with an emphasis on least cost security constrained dispatch without regard to ownership[3]. There was some disagreement on the precise measure of these benefits.

A. Observations

- *Benefits from economic dispatch*

The NYISO estimated the benefits of SCED at roughly 100 million dollars per year from 1977 to 1999 yielding a cumulative benefit of 2 billion dollars[4]. A savings of 281 million dollars or roughly 24 percent of the total market transactions was cited in 1981. Precise estimates for the period since 1977 were not cited. However, the NYISO has made several enhancements to SCED since then and estimates that the benefits have likely increased even further. The NYISO cited estimated a five percent decline based on average monthly costs on a fuel adjusted basis from 2000 – 2004[5].

ISO-NE cited an estimated total savings due to the regional economic dispatch from 1970 – 1977 at over $1.4 billion in 2004 dollars[6]. The ISO-NE cited a 5.6 percent reduction in the average wholesale cost of electricity from 2000-2004 which translates to a 700 million dollars per year after netting out fuel costs[7]. The ISO-NE also noted a 5 - 6 percent improvement in generator availability and significant new investment as a result of the advent of markets.

Despite the extensive references to the benefits of economic dispatch and markets in general, there were also concerns raised on related market issues (e.g., the impact of high gas prices on uniform price markets) as well as a discussion of further improvements than can be made, e.g. improved inter-regional coordination, better modeling of constraints in software etc. In the remainder of this section, we summarize some of the major issues that were brought up.

- *Benefits of economic dispatch and benefits of markets*

There was considerable discussion at the meeting on the benefits that have been realized through markets. Some participants suggested that since economic dispatch is a required enabler of markets, it makes sense to look at the benefits created by the market as a whole when evaluating the benefits of economic dispatch[8]. Others disagreed observing that

[3] Mr. Bolbrek at p 111 of transcript.
[4] Mark Lynch at p 49 of transcript.
[5] Mark Lynch at p 59 of transcript.
[6] Gordon van Welie at p 66 of transcript.
[7] Gordon van Welie at p 68 of transcript.
[8] Gordon van Welie at p 67 of transcript.

economic dispatch does not necessarily require markets[9].

Some participants observed that improvements in generation availability may not be entirely attributable to the introduction of LMP based day-ahead markets but rather a result of how capacity credits are calculated[10]. Measuring the benefits of economic dispatch precisely can be complex[11].

- *Concerns about efficient vs. economic dispatch*

Some participants raised questions about whether economic dispatch can ensure efficient dispatch[12]. The difference between economic and efficient dispatch has been discussed in the recent DOE report related to section 1234 of EPACT. The reasons the two can be different are two-fold (1) if the entire set of available resources is not considered as an input to the economic dispatch algorithm, the result will not be efficient[13], and (2) if offer prices do not reflect costs, the dispatch may not be efficient from a heat-rate perspective[14].

B. Specific Market and Dispatch Issues

- *Wider geographical scope of economic dispatch*

Some improvements such as the elimination of pancaking in rates have already been made[15]. Other improvements that are under way include better inter-regional transaction scheduling and pricing of external nodes[16]. Overall, there appears to be consensus that better coordination of dispatch across interfaces within the region (e.g. New York and New England) as well as interfaces with external areas (e.g., PJM and Canada) is desirable. However, some participants also raised caution on what might be a reasonable expectation of benefits.

---

[9] Mr. Rudebusch at p 162 of transcript.
[10] Mr. Bolbrock at p85 of transcript.

[11] Mr. Burke at p 99 of transcript.

[12] Keating, Meyer and Meroney at pp 26-30 of transcript.

[13] Meroney at p 28 of transcript.

[14] Keating at p 30 of transcript.

[15] Mark Lynch at p. 60 of transcript.
[16] Gordon van Welie at p 78 of transcript.

There is disagreement on specific approaches to improve coordination of economic dispatch between New York and New England. Some participants favored improvements realized through improved transaction scheduling by market participants on a shorter time frame than is available currently, while others favored a stronger integration using a "Virtual Regional Dispatch" (VRD) model[17]. Both the New York ISO and ISO New England have looked at the VRD approach for some time with little actual progress on implementation. More recently, they have started looking at taking smaller steps by improving the granularity of scheduling across their boundaries under the Interregional Transaction Scheduling or ITS project. By allowing schedules to be submitted closer to real-time and more frequently, the expectation is that market participants would be able to capture at least some of the benefits that can come from a fully integrated economic dispatch. Some participants raised concerns about implementation complexity and costs[18].

- *Concerns about uniform price markets*

In response to the recent high gas prices and their impact on electricity prices, there have been concerns expressed about uniform clearing price markets and whether there could be additional savings under other market models[19]. A report written during the California power crisis that explained the benefits of uniform price auctions and why it ultimately results in lower prices for customers was cited[20]. However, some participants expressed a desire to revisit the issue using actual bidding data and a more realistic assumption of generation mix[21]. Some participants noted that economic dispatch does not necessarily require a single clearing price methodology and took issue with prices set by gas fired plants being paid to coal and nuclear plant[22]. Other participants noted that the alternative design of pay-as-bid auctions could potentially result in lower overall prices but this would destroy incentives for cost reflective bids, which in turn would lead to inefficient dispatch and may not be worth the complexity[23].

---

[17] See comments submitted by National Grid, Dan Allegretti at p 106 and Michael Calviou at p 118 of transcript.

[18] Mr. Loughney at p 160 of transcript.

[19] Commissioner Brownell at p 97 of transcript.

[20] Gordon van Wylie at p 97 and p 182 of transcript. The report "Pricing of the California Electricity Market - Should California Switch from Uniform Pricing to Pay-As-Bid Pricing" is available as a part of the record.

[21] Bob Loughney at p 158 of transcript.

[22] Mr. Rudebusch at p 162 of transcript.

[23] Harry Singh at p 187 and Don Sipe at p 198 of transcript.

- *Improvements in modeling of unit operational constraints and transmission constraints in economic dispatch*

Some participants raised concerns about dispatch actions taken outside the security constrained economic dispatch software[24]. Such actions are necessary when either the operational constraints of generators or transmission constraints cannot be fully represented within the software. Generating sources dispatched in this manner do not affect the calculation of market prices and are paid separately via an uplift payment. If uplifts are improperly allocated to market participants they can have additional adverse affects on markets. One example cited at the conference was the impact of uplifts allocations in New England and their impact on virtual trading. The allocation has recently been modified to address the problem[25]. One participant noted that the biggest issue is the challenge in reflecting all security constraints in security constrained unit commitment and security constrained economic dispatch[26].

There have been recent improvements to dispatch models used in the Northeast. For example, NYISO introduced in February 2005, enhancements to its real time dispatch software that allows co-optimization of energy and reserves in addition to a shortened evaluation period for real-time unit commitment[27].

Uplifts can often result from limitations of software in modeling physical constraints, e.g. combined cycle plants in unit commitment in the Boston area. The economic impact of such uplifts can in some instances be greater than efficiency gains on seams issues. The ISO-New England has therefore made addressing this issue a high priority[28].

Other improvements such as the use of Mixed Integer Programming (MIP) software for better combined cycle generator modeling are being considered but are in the research and development phase[29].

- *Incorporation of demand response into economic dispatch*

There are opportunities for better integration of demand response in economic dispatch that can further improve infrastructure utilization[30]. This is an area where state regulators

---

[24] Pete Fuller at p. 43, Dan Allegretti at p 105 and Steve Corneli at p 139 of transcript.
[25] Steve Corneli at p 140 of transcript.
[26] Steve Corneli at p 138 of transcript.
[27] Mark Lynch at pp 59-60 of transcript.
[28] Gordon van Welie at p 78 of transcript.
[29] Gordon van Welie at p74 of transcript.
[30] Gordon van Welie at p 72 and p 83 of transcript and Burke at p 93 of transcript.

and the RTOs can work together. Participants noted that while organized markets have generally similar demand response programs, there are also differences. For example, ISO New England considers demand response to be a critical resource that can be drawn upon in the absence of quick start peaking resources and has made efforts to incorporate demand response into its commitment and dispatch software[31].

- *Further Improvements in market transparency*

Many participants noted the significance of transparent price signals in making markets work better and encouraging investment. Some participants expressed a desire to allow releasing market bid data sooner than the six-month lag with which is released currently[32]. They cited other markets such as the UK and Australia where this is done on a daily basis and argued that US markets have now matured enough to allow this data to be released sooner. The ISO-NE responded saying they would be open to such a suggestion and the right venue to discuss it would be the stakeholder committee process[33].

- *Better utilization of the interconnections with External Areas*

Additional benefits of economic dispatch may be possible by looking by looking at external interfaces with regions outside New York and New England. A specific example was the 2000 MW limit on the Phase 2 HVDC U.S. Interconnector between New England and Quebec that is currently being used at 1200 MW due to constraints further down the system in New York and PJM[34]. A decrease in flows from Quebec to New York may be able to yield as much as three times higher flows into New England. Thus, further benefits for the region may be possible by improved coordination between New York, New England and Quebec.

- *Capacity markets and new investments*

One participant noted that existing markets have not performed well in promoting new investment through price signals. Instead, new investment is largely driven by contracts arranged via RFPs. A missing element of markets in the region relates to the refinement

[31] Gordon van Welie at p 90 of transcript.
[32] Michael Calviou at p 122 and Doug Horan at p 148 of transcript.
[33] Gordon van Welie at p 129 of transcript.
[34] See Michael Calviou at p 120 of transcript.

of existing mechanisms for capacity markets[35].

C. Recommendations from the DOE Report to Congress

The DOE Report to Congress, The Value of Economic Dispatch, contains three recommendations that are relevant to the security constrained economic dispatch issues that the Joint Board has been considering. These three recommendations are described below.

- FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some IOUs, to determine how they conduct ED. [36] These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business practices should from regulatory, environmental and reliability-driven constraints. These reviews could assist FERC and the states in rethinking existing rules or crafting new rules and procedures to allow NUGs and other resources to compete effectively and serve load.

- FERC and DOE should explore EPSA and EEI proposals for more standard contact terms and encourage stakeholders to undertake these efforts.[37] Specifically, the EEI proposed that NUGs should commit to provide energy at specified price for specified time to meet unit commitment schedule and there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.

- Current economic dispatch technology tools deserve scrutiny.[38] These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

---

[35] Steve Corneli at p 142 of transcript.

[36] The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005, United States Department of Energy, November 7, 2005, page 52.

[37] Ibid, p 51.

[38] Ibid, p 53.

V. Board Recommendations

A. Further Improvements in Market Transparency

While not directly related to the implementation of SCED, improved market transparency is important for monitoring and establishing confidence in the pricing and dispatch determined by SCED. A proposal was made to allow market bid data to be released with a less than six-month lag. The six-month lag was introduced to protect market participants from having to reveal current operations and competitive bidding strategies, and to discourage collusion. However, a shorter lag period would provide quicker public access to bid data, which would strengthen public monitoring of market behavior and help ensure confidence in the competitiveness of the markets; it would also enhance the ability of market participants to quickly identify inefficiencies. One party suggested that a month's delay would be sufficient to protect market participants.[39] Another party observed that other electricity markets in the U.K. and Australia release bid data on the day or the day after the market outcome.[40] ISO-NE and NYISO stated that they were open to suggestions on making market bid data available with a shorter lag time and that this should be pursued through the appropriate ISO committee processes.[41] No party objected to this proposal.

APPA submitted comments questioning whether bids reflected actual marginal costs, or whether bids might be inflated due to market power.[42] This question cannot be answered solely by providing better access to bid data; it also requires information about "actual" marginal costs, which involve confidential supplier information. For this reason, APPA requested an analysis by the Northeast Joint Board comparing generator bids to their actual marginal costs, as supplied to ISO-NE and NYISO.

<u>Recommendation:</u> 1) ISO-NE and NYISO should pursue, with market participant input, making market bid data available to the market with a shorter lag time. 2) **NYISO and ISO-NE have market monitoring responsibilities with FERC oversight. For example, NYISO's Market Power Mitigation Measures (OATT Attachment H) defines procedures for calculating "reference levels" for bids based on estimates of actual marginal costs, and establishes mitigation measures (including reducing bids to reference levels) when the bids appear to represent an abuse of market power (i.e. would raise prices significantly above competitive levels). Any concerns associated with market power should be addressed as part of ISO market monitoring efforts, not in this proceeding.**

---

[39] NSTAR Electric – Doug Horan, p. 149 of transcript.

[40] National Grid - Michael Calviou, p. 122 of transcript.

[41] Gordon van Welie at p. 129 of transcript; Mark Lynch at p. 13 of 2/13 transcript.

[42] American Public Power Association, "Re: Joint Boards on Security Constrained Economic Dispatch, Docket No. AD05-13-000 (Northeast Region)", letter of 2/17/2006.

B. Wider geographical scope of economic dispatch

Participants generally agreed that just as there are significant benefits associated with utilizing SCED in any given region, there are additional benefits to be derived by expanding the scope of economic dispatch over a wider geographic area, but there are also significant impediments and drawbacks to implementing a single SCED regime for, for example, the New York and New England regions combined. However, much of the benefit of a larger scope can be obtained by improvements that would allow electricity to flow between regions in a more economically efficient manner. The impediments to those more efficient flows are commonly referred to as "seams" issues, and these issues can relate to differing regional market rules, operating or scheduling protocols, and many other causes. Much progress has already been made in this area, with the elimination of through-and-out rates and improved transaction checkout procedures between New York and New England. The main focus of the participants in the Northeast to address this problem centered on two general proposals commonly referred to as Intra-hour Transaction Scheduling (ITS) and Virtual Regional Dispatch (VRD)[43]. The ITS proposal focuses on improving the processes to allow market participants to more effectively be able to schedule power flows between regions in response to changing prices and system conditions, and in particular to be able to do so in a shorter timeframe than is now possible. The VRD proposal would allow ISOs and RTOs themselves to change interchange power flows between each other if appropriate when the interchange schedule set by market participants' transaction schedules result in an inefficient dispatch.

<u>**Recommendation:**</u> **Thus far neither proposal has been developed in sufficient detail to be implemented. We recommend that both NYISO and ISO-NE work together and with the market participants towards the development of mechanisms to address the specific seams issues discussed here. As an initial step, both NYISO and ISO-NE should meet within 90 days to coordinate their initiatives and file a plan with FERC describing the time line to address the seams discussed in this section.**

C. Improvements in modeling of unit operational constraints and transmission constraints in economic dispatch

Market participants[44] correctly pointed out that not all unit and system constraints are modeled in the security constrained economic dispatch software used by ISO-NE and

---

[43] It should be noted a major seam, transmission rate pancaking between the two control areas, has already been eliminated.

[44] Pete Fuller (p. 43), Dan Allegretti (p. 105), Steve Corneli (p. 139) in 11/29/05 Northeast Joint Board for Economic Dispatch transcript.

NYISO. The resulting impacts vary from the need for human intervention in the dispatch to the addition of uplift charges which distort market prices[45]. Component models for multiple combined-cycle unit configurations are being refined and their use would allow for more accurate modeling of large units[46] and result in an improved economic dispatch. Where these improved models have not yet been incorporated into the dispatch, they should be scheduled for inclusion in the next software upgrade.

The increased modeling of system constraints (e.g. include voltage and stability constraints) would result in more precise dispatches and result in better market signals[47]. Technology, however, stills need to advance before implementation can be initiated. The principle tool for incorporating additional system constraints is the security constrained optimal power flow (OPF) program. The basic difference between today's security constrained unit dispatch software and a security constrained OPF is the use of an AC power flow instead of a DC power flow-based program. The switch to AC-based software would increase the run time for a single scenario from minutes to well over an hour with today's technology. Therefore, the use of a security constrained OPF even in the day-ahead markets is impractical at this time. The ISOs should monitor the technology for increased processing speed with the goal of switching to a security constrained OPF for economic dispatch when it is feasible.

Recommendation: The NYISO and ISO-NE should incorporate additional unit and system constraints in economic dispatch software as modeling and technology improve.

D. Incorporation of demand response into economic dispatch

Some participants called for better integration of demand response into economic dispatch and for state regulators and RTOs to work together on this. The NYISO already allows demand response programs – the Special Case Resource and Day Ahead Demand Response program - to participate and compete with generation. In addition, FERC has recently directed the NYISO to allow demand response participants to offer demand side response in the ancillary services market[48]. Continued improvements should be coordinated through the NYISO working groups, to ensure that the proposals will be practical and will work as intended.

---

45 Commissioner Nora Brownell (p. 16) in 2/13/06 Northeast Joint board for Economic Dispatch transcript.

46 Gordon van Welie (p. 74) in 11/29/05 transcript.

47 Ibid.

48 ER04-230-010, ER04-230-014 and ER04-230-019; Letter from FERC to NYISO dated January 26, 2006.

ISO-NE currently administers five demand response programs including three real-time programs that support system reliability and two programs that provide incentives for demand to respond to high real-time or day-ahead wholesale market prices. ISO-NE's goal is to transform these currently out-of-market programs into ones that are directly integrated into the region's wholesale and retail electricity markets. To this end, ISO-NE's Ancillary Services Markets (Phase II) project will integrate "asset-related demands" into real-time operations, which would allow demand resources to more efficiently balance load and generation and offer reserve services in real time. Additionally, ISO-NE will also be implementing a Demand Response Reserves Pilot Project to determine the ability of small demand resources (e.g., less than 5 MW) to meet operational requirements for reserve resources and to investigate more cost-effective communication and telemetry solutions that would allow small resources to participate in the wholesale electricity markets. Finally, ISO-NE will be engaged in a project to integrate demand resources into the Forward Capacity Market, should the Commission approve the recently-filed settlement agreement in FERC Docket Nos. ER03-563-000, -030, and -055.

Further, NYPSC is actively promoting dynamic electric pricing for large customers that would facilitate Demand Response. For example, the NYPSC recently implemented mandatory hourly pricing as the default rate for large customers[49]. This could place over 5,000 MW of load on the hourly pricing default tariff in the coming months. Currently, none of the New England States require default service to be priced on a dynamic basis. Accordingly, ISO-NE has approached the New England Conference of Public Utility Commissioners (NECPUC) to analyze, design, and implement dynamic pricing solutions that would capture greater price-responsive demand in the New England region. To date, ISO-NE has sponsored studies quantifying the benefits of dynamic pricing and recently submitted testimony in a Connecticut regulatory proceeding recommending that a dynamic rate be applied to default service for customers with maximum demands greater than or equal to 350 kW. The proposed rate included a three-part, time-of-use, variable peak pricing design applicable to the commodity portion of service where the Peak Period Rate would be based on the average of the corresponding hourly Day-Ahead Energy Market prices during the peak period (defined as 1:00 p.m. to 7:00 p.m. weekdays) for the applicable day and Load Zone.

<u>Recommendation:</u> We believe that incorporation of Demand Response in the wholesale market is making progress in both NYISO and ISO-NE. In addition, regulators in New York are promoting dynamic pricing for retail electric customers. Efforts are underway in New England to include these resources in developing markets. We expect these efforts to continue, and as a result to provide greater opportunities for market participation by these resources. With these ongoing

[49] Case 03-E-0641, Proceeding on motion of the Commission regarding expedited implementation of mandatory hourly pricing for commodity service.

initiatives, we do not recommend any additional requirements as part of this proceeding.

E. Better utilization of the interconnections with External Areas:

Increased use of interconnection capability provides opportunities for additional economic interchange of energy. However, it has long been recognized in regional planning that power transfers between control areas can impact system operations in other control areas. To date, most analysis has revolved around the principle of "do no harm" such that if inter-tie transfers produced negative operational impacts in the other control areas, the transfer levels are limited to below those impact thresholds. Economic studies have generally not taken place to determine if it would be beneficial to increase the inter-tie transfers and make arrangements with the other control area to take mitigating measures. An example offered is the Quebec-New England inter-tie where transfer levels are limited by constraints in New York and PJM. There are some indicators that a 100 MW reduction in transfers between Quebec and New York, coupled with leaving the 100 MW system capacity in New York unloaded, would increase the transfer capability from Quebec to New England by 300 MW.[50]

__Recommendation:__ The ISOs should investigate better utilization of their interconnections with other areas which could provide additional economic transaction opportunities. The ISOs should perform a technical evaluation of its inter-ties, including the Quebec-New England inter-tie, to determine a) what operating adjustments in other control areas could be made to accommodate increased use of the inter-ties; and, b) what system upgrades would be required to fix the constraint.[51] The ISOs should then perform a market-impact analysis of the expanded use of the inter-ties. As a threshold, the analysis should determine if there would be a net region-wide benefit from the proposed increased use of the inter-ties and how they would be spread across control areas. If there is not a net benefit, inter-tie maximization should be deferred. If there is a net regional benefit, operating adjustments and cost impact mitigation strategies should be identified and protocols developed to make these opportunities available to the market. The possibility of system upgrades should be included in regional planning processes for evaluation in those forums.

---

[50] Michael Calviou (p. 120) in 11/29/05 transcript.

[51] Commissioner Nora Brownell (p.20) in 2/13/06 transcript.

F. Refining capacity markets

Some participants called for refinements to capacity markets in order to promote new investment. Commissioner Brownell noted that there were many efforts underway across the northeast regarding capacity markets, but due to ex-parte rules, it would not be appropriate to address those efforts here.[52]

<u>Recommendation:</u> No further action is recommended in the context of this proceeding given the current proceedings underway. However, FERC should continue to evaluate potential seams issues with neighboring regions as new market designs are adopted.

G. Re-examining uniform price auctions

All suppliers in the spot market are paid the uniform spot market price determined by SCED, adjusted for line losses and congestion. Of course, most supply is sold prior to the spot market at contractual prices, so that only a small portion of supply is actually paid the spot price determined by SCED. However, the spot market price does provide a benchmark for comparison to contractual prices. Moreover, all suppliers must participate in SCED to coordinate overall supply and demand.

Some participants called for re-examining the use of uniform price auctions that allow gas fired generators to set the price for coal and nuclear plant.[53] Gordon van Welie (ISO-NE) explained that under the current uniform price auction, baseload units such as coal and nuclear plants may act as "price takers," bidding their marginal cost, which may be zero, in order to guarantee they are dispatched. They are paid the uniform clearing price, which is generally above their marginal cost; the difference goes towards recovering their capital investment and other fixed costs. The debate has been over the "pay-as-bid" approach, in which suppliers whose bids were accepted (and thus were dispatched) would be paid their individual bids rather than a uniform clearing price. However, under the pay-as-bid approach, baseload units would have to change their bidding strategy: In order to recover the same capital investment and other fixed costs, they would have to increase their bids to a level reflecting their estimates of the market clearing price. So there would not be much difference in the prices paid, but the pay-as-bid method would be less robust than the current uniform price auction in terms of producing efficient dispatch. Other participants elaborated that, under pay-as-bid, baseload units might submit bids slightly below their estimate of the market clearing price, in order to guarantee dispatch; this could potentially result in baseload units being

[52] Commissioner Brownell at p. 23 of transcript of 2/13/2006.
[53] Tom Rudebusch at p 162 of transcript.

paid a little bit less on some occasions, but it would destroy incentives for cost reflective bids, which in turn would lead to inefficient dispatch and may not be worth the complexity. Moreover, adopting pay-as-bid in order to try to reduce payments to baseload units would discourage future investments in baseload generation.[54] A report written during the California power crisis that explained the benefits of uniform price auctions and why it ultimately results in lower prices for customers was cited.[55] However, some participants expressed a desire to revisit the issue using actual bidding data and a more realistic assumption of generation mix.[56]

Some participants argued that, under the uniform price auctions, the only way loads can capture the benefits of lower cost coal and hydro resources is via long-term bilateral contracts or investments in new baseload projects.[57] Mr. Van Welie observed that the high prices facing consumers in the Northeast are due to their over-dependence on natural gas-fired generation. The solution is not to change the market design, but to change the siting rules to permit greater investment in new baseload generation that does not depend on natural gas.[58] Mark Lynch added that the Northeast's existing market design is producing all the right price signals; but to ensure new entry, the siting issues must now be resolved.[59]

<u>Recommendation:</u> The current uniform clearing price approach has been in place for several years. Comments in this proceeding do not justify a departure from the established uniform clearing price model. We do not make any recommendation about this approach at this time.

H. Review dispatch practices

The DOE report (p.52) noted a lack of easily comparable information regarding dispatch models and implementation by different entities and areas, and recommended that the FERC-State Joint Boards consider conducting in-depth reviews of selected dispatch entities, including some investor-owned utilities, to determine how they conduct economic dispatch. These reviews would document all deviations from pure least-cost, merit-order dispatch and distinguish entity-specific or regional practices from regulatory,

---

[54] Harry Singh at p 187 and Don Sipe at p 198 of transcript.

[55] Gordon van Wylie at p 97 and p 182 of transcript. The report "Pricing of the California Electricity Market - Should California Switch from Uniform Pricing to Pay-As-Bid Pricing" is available as a part of the record.

[56] Bob Loughney at p 158 of transcript.

[57] Tom Rudebusch at p. 163 of transcript.

[58] Gordon van Wylie at p. 172 of transcript.

[59] Mark Lynch at p. 175 of transcript.

environmental and reliability-driven constraints, with an eye toward identifying potential discrimination against certain resources. While discrimination against NUG resources is not an issue in the Northeast in that ISO-NE and the NYISO commit and dispatch resources without regard to ownership, the NYISO is currently, in conjunction with its review of rules applicable to wind and solar power, commencing a global review of its rules to ensure that all types of resources are treated equitably.

Recommendation: **We do not recommend any additional steps be undertaken in this proceeding beyond what NYISO and ISO-NE are contemplating doing as part of their regular improvements to their operations.**

I. Standardize Contract Terms

The DOE report (p.51) recommends that DOE and FERC should explore the EPSA and EEI proposals for more standard contract terms and conditions for NUG-to-buyer contracting and should encourage stakeholders to undertake these efforts, which should benefit the entire wholesale electric industry and its customers. These proposals relate to the conditions for inclusion of NUG resources in a utility's economic dispatch queue and their provision of ancillary services such as voltage support and regulation, along with associated performance standards, compensation and penalties. ISO-NE and the NYISO both dispatch generation resources without regard to ownership and compensate and penalize units according to established FERC-approved tariff rules.

Recommendation: **This recommendation does not appear to be relevant to the Northeast Board, and for regions without organized markets might better be addressed in an industry forum such as the NAESB.**

J. Review Dispatch Tools

The DOE report (p.53) noted the diversity of size and scope of the various dispatch areas and recommended scrutiny of the technical quality of current economic dispatch technology tools including software, data, algorithms, and assumptions, with an eye toward enhancements to these tools and elimination of any inherent resource biases.

Recommendation: **Given that the most advanced tools and models to date have been developed and administered by the nation's ISOs and RTOs, it is recommended that FERC request of the ISO-RTO Council (IRC) to take the lead in identifying "best practices" to guide future improvements to these tools.**