ISO MOU Seams Issues
Best Practices Review
Draft - 2/02/01

NYSEG has reviewed the high priority issues developed during the MOU Working Group Meetings ("SEAMS Issues") and has identified the existing practices or ideal characteristics ("Best Practices") that will facilitate and simplify inter-control area transactions when implemented by the Northeast ISOs (hereinafter, "ISOs"). This position statement offers examples that focus primarily on changes intended to improve interchange transactions between PJM and NYISO but anticipates that Best Practices will be implemented by all Northeast ISOs.

So long as the Best Practices are implemented by Summer 2001, each of the SEAMS Issues share the same priority. Nevertheless, NYSEG recommends below an order in which the Best Practices may be implemented to achieve optimum results. For example, standardizing the way TTC is determined and adjusted (an ATC/TTC Best Practice) will help to resolve scheduling and ramping issues. References below to an ISO are intended to apply to all Northeast ISOs.

1) ATC/TTC

ATC, as defined in Order No. 888, is a measure of the amount of transmission capacity available to be reserved for transmission service. TTC is a fixed value for each transmission path that varies only when the physical characteristics of the transmission equipment vary (e.g., temperature limitations, physical degradation). ATC is not a useful data point when calculated for a system that does not require transmission capacity reservation but is continuously redispatched based upon financial parameters. Instead of ATC, market participants require access to real-time flow information in an understandable format. By establishing a standard definition and method for determining TTC across the ISOs and by providing real-time flow information, market participants will be better able to decide whether inter-control area transactions are economically and physically feasible.

Implementation of the Best Practices applicable to the ATC/TTC SEAMS Issue does not require a major change to software systems in any of the control areas and should be completed by May 1, 2001.

Best Practice:

- Clearly and consistently define TTC for each of the ISOs. Each ISO must verify its calculations of TTC at common border interfaces with the bordering ISO before posting the values. The values at interfaces of bordering ISOs must be equivalent. For example, where two ISOs calculate a different TTC for the same border interface, the TTC for both ISOs would equal the lower TTC value, unless both ISOs conferred, recalculated, and agreed upon the higher value or some value in between. Clearly, the highest achievable TTC is preferred.

- TTC should be changed only to reflect actual physical changes in the transmission equipment capacity and not for economic considerations such as reducing internal congestion, which should be addressed through generation redispatch. The conditions under which TTC will be changed must be proceduralized and common to the ISOs. When an ISO changes a TTC value, the reason, the value, and duration for such change must be posted on the ISO's OASIS at the time the change occurs (in real-time).

- Each ISO must post and update bid amounts (MW amounts, not financial bids), and scheduled and actual flow information for each boundary interface in real time in each direction. Posting only the net values is insufficient. For example, each ISO must post:

  a. All MWs bid to be imported
  b. All MWs bid to be exported
  c. All MWs scheduled as imports
  d. All MWs scheduled as exports
  e. Scheduled DNI values and updates
  f. Actual flows in real time

- Transmission Outage Schedules should be posted as far in advance as possible and updated as soon as changes in schedules are identified. The posting should include (a) any limiting circumstances that could cause changes in the outage schedule (e.g., cancellation due to inclimate weather, dependence upon performance of other outages), and, (b) where a change to a scheduled outage is requested and granted, the identity of the requesting party and the duration of the change.

  For example, the ISOs could develop a three-category system classifying planned transmission facility outages based on their probability of occurrence, e.g. High, Medium and Low. Outages required to maintain reliability and outages not dependent on fair weather would be examples of High Probability Outages. Medium Probability Outages might include outages that would be cancelled or postponed during periods of unexpectedly high load or inclement weather. Low Probability Outages could include outages that the Transmission Owners are likely to reschedule to accommodate a variety of considerations, such as construction crew availability. Market participants could use outage probability information to evaluate and hedge congestion and curtailment-related risk. The ISOs would monitor the probability designation assigned to each outage to ensure such designations and changes were appropriate and consistent with the protocols.

2) **Ramping, Scheduling and Check-out of Interchange Transactions**

Disparity in the way the ISOs schedule and effect inter-control area exchange is an obstacle to the development of liquid markets.

First, the ISOs do not have the same scheduling flexibility. In PJM, a market participant can submit a schedule that allows for four (4) adjustments in each hour. For example, the schedule for Hour 1 could provide for 500 MW at the beginning of the hour, an increase to 525 MW at 15 minutes after the hour, an increase to 600 MW at half past the hour, and a decrease to 550 MW at 45 minutes after the hour, so long as the entire schedule was submitted no later than 20 minutes before the start of the dispatch hour. In contrast, the NYISO requires all schedules to be submitted no later than 90 minutes before the start of the dispatch hour and provides for no adjustments during the hour.

Second, PJM and NYISO have placed different limitations on the rate at which each control area can vary interchange. PJM schedules changes in generator output ("Ramp Rate") of 2000 MW in an hour (at a rate of 500 MW each 15-minute interval). The NYISO has limited itself to a Ramp Rate of 700 MW in an hour. Overly restrictive Ramp Rates contribute to energy supply shortages during peak load periods by reducing energy import capability. Common scheduling and ramping procedures (e.g., use of standardized ramp rates and scheduling frequencies) between the ISOs will minimize the scheduling and ramping confusion, improve inter-control area transaction management, and facilitate development of liquid markets.

Third, market participants have difficulty transacting across control area boundaries that use dissimilar market models. Market participants often require actual physical delivery (e.g., block transaction), not just a financial settlement. Curtailment of delivery, not withstanding that financial settlement through the New York ISO might make a market participant financially whole, has resulted in the inability to restart the generator's transactions (e.g., because of lost ramp space) and lost opportunity costs. For example, assume a market participant schedules a sixteen (16) hour transaction from PJM to NY with a decremental bid.

Assume further that the NYISO selects the decremental bid in Hour five (5) but then rejects the bid every hour thereafter. If the ramp space that the market participant was relying upon in PJM to export to NY is no longer available, then the market participant will be unable to supply the energy (from its generation resource) for the remaining hours of its transaction and will be forced to repurchase that energy in the NYISO market or from another source. In the end, the supplier would have preferred that the NYISO treated its transaction in New York the same as it was treated by PJM – as firm transmission service with physically delivery.

Fourth, the scheduling process, which requires data entry in several software systems for a single interchange transaction, is unwieldy. If transaction information is entered incorrectly in one system, the transaction schedule, at least in NY, fails check-out and is rejected.

Fifth, PJM and NY model the same border interfaces differently. PJM models NY as a two-zone or interface system (East and West) whereas NY models PJM as a single zone or interface (PJM). Because of the congestion on Central East, modeling NY as a single interface is inaccurate, leads to proxy bus price disparity and may contribute to ramping problems experienced between PJM and NY.

Best Practices:

- The ISOs should provide the same scheduling flexibility and have the same schedule submission deadline. Following PJM's practice, each ISO should allow four (4) in-hour schedule changes. The scheduling deadline for real-time market transactions for all ISOs should be the same and as close to the beginning of the dispatch hour as practicable. Currently, ISO-NE accepts changes until 30 minutes before the hour; PJM accepts changes 20 minutes before the hour; and NYISO accepts changes until 90 minutes before the hour. The NYISO should run its evaluation software at the same frequency that schedule adjustments are permitted.

- Neighboring ISOs should use the same Ramp Rates for common interfaces. The Ramp Rate selected should be the highest common Ramp Rate practicable.

- Each ISO should develop a common modeling system for each control area.

- A centralized checkout process for ISO to ISO transactions should be established allowing for a single contact point for the Northeast market.

- Each ISO must accept block bids scheduled on an all or nothing basis similar to the manner in which the NYISO allows generators to designate blocks of energy through submission of a minimum run-time.

- Adjacent control areas must agree on a consistent or coordinated set of transmission rights between the control areas. In the absence of PJM converting to a financial system or NY/NE converting to a physical rights system, a hybrid of the two approaches must be implemented. Ultimately, a single congestion management system must be employed.

- Checkout should be coordinated better between Control Areas. Each ISO should check-out interchange transaction schedules with each other, rectify any inconsistencies, and then post the accepted schedules.

- If the NYISO identifies data problems or mistaken entries during the check-out process, it should follow PJM's practice of contacting the market participant and rectifying the error rather than rejecting the schedule. The scheduling data entry process is complex and unwieldy, and mistakes are common.

- A common electronic system for tracking transactions should be established so information can be passed freely between Control Areas, duplicative data entry into multiple systems can be eliminated, and ISOs can be certain that they are reviewing the same information.

3) Energy Pricing at Boundary

In a fluid energy market, the energy price at the boundary of two adjacent control areas should converge when adjusted for congestion and delivery charges. NYSEG believes that the current mismatch in the commodity price (between PJM and NYISO proxy bus prices) will be resolved or greatly reduced when the Best Practices to address the ATC/TTC and Ramping, Scheduling, and Check-out issues are implemented and the ISOs ultimately use a common process to perform unit commitment and real-time dispatch. The Energy Pricing concern should not be listed and treated as if it is a separate issue.

4) Trading Hubs

Trading Hub development, although an important enhancement to markets, should wait until after the Best Practices described above are implemented.