MINUTES OF THE
JOINT NEPOOL MARKETS COMMITTEE/NYISO MARKET ISSUES WORKING GROUP MEETING
HELD ON MONDAY, FEBRUARY 14, 2011
IN SPRINGFIELD, MASSACHUSETTS

NEPOOL Markets Committee

Attendee	2/14		Member/ Alternate	Market Participant
A. DiGrande	✔		Chair	ISO New England Inc.
N. Bosse	✔*		Member	Brookfield Energy Marketing, Inc.
C. A. Bowie	✔		Member	Northeast Utilities Service Company
			Temporary Alternate	NSTAR Electric Company
D. J. Capra	✔*		Temporary Alternate	GDF Suez Energy Resources NA
N. Chafetz	✔*		Temporary Alternate	Customized Energy Solutions for BP Energy Company, Energy America, LLC, Hess Corporation and Integrys Energy Services, Inc.
J. Dannels	✔		Member	Consolidated Edison Energy, Inc.
F. P. DaSilva	✔		Member	NextEra Energy Resources, LLC
M. A. Erskine	✔*		Alternate	Central Maine Power Company
F. Ettori	✔		Member	Vermont Electric Power Company, Inc.
J. Gawronski	✔		Member	United Illuminating Company
J. S. Gordon	✔		Member	PSEG Energy Resources & Trade LLC
L. Guilbault	✔		Member	H.Q. Energy Services (U.S.) Inc.
G. Haake	✔*		Member	Dynegy Power Marketing, Inc.
T. Kaslow	✔		Vice-Chair/ Member	GDF Suez Energy Resources NA/FirstLight Power Resources Management, LLC
W. Killgoar	✔		Member	Long Island Power Authority (LIPA)
S. Kirk	✔		Member	Constellation Energy Commodities Group, Inc.
A. W. Kuznecow	✔		Secretary	ISO New England Inc.
R. B. Mackowiak	✔*		Member	Entergy Nuclear Power Marketing LLC
F. Plett	✔		Alternate	Mass Attorney General's Office
J. A. Rotger	✔		Member	Cross Sound Cable Company, LLC
P. C. Smith	✔		Member	GenOn Energy Management, LLC
R. de R. Stein	✔		Alternate	Signal Hill for H.Q. Energy Services (U.S.) Inc.
B. Trayers	✔		Member	Citigroup Energy Inc.
J. Wadsworth	✔		Member	Vitol Inc.
J. Warshaw	✔		Member	NSTAR Electric Company
S. J. Weber	✔		Member	PPL EnergyPlus LLC
G. Will	✔		Member	MMWEC
			Temporary Alternate	CMEEC
Guest				Affiliation
J. W. Bentz	✔			NESCOE
E. Buzaid	✔*			Day Pitney
P. Chattopadhyay	✔*			NH PUC
R. Coutu	✔			ISO New England Inc.
J. Dombrowski	✔			ISO New England Inc.
J. Douglass	✔*			ISO New England Inc.
J. Dwyer	✔			ISO New England Inc.
R. Ethier	✔			ISO New England Inc.
S. Hann	✔			ISO New England Inc.
C. Mendrala	✔			ISO New England Inc.
H. Mertens	✔			VT DPS
R. Pelletier	✔*			MA DPU
S. Sciarrotta	✔			Vermont Electric Power Company, Inc.

J. Scalabrini	✔			ISO New England Inc.
M. Walton	✔			ISO New England Inc.
M. White	✔			ISO New England Inc.
F. Zhao	✔*			ISO New England Inc.

* -- Indicates participated by telephone

NYISO Market Issues Working Group				
Attendee	**2/14**			**Organization**
A. Ackerman	✔*			Galt Power Inc.
G. Bissell	✔*			Couch White, LLP for Multiple Intervenors
M. Bowman	✔			NYSDPS
R. Boyle	✔			NYPA
C. Brown	✔			NYISO
L. Bullock	✔*			NYISO
P. Caletka	✔			NYSEG
M. Cadwalader	✔*			Representing TO's
D. Clarke	✔*			Long Island Power Authority
P. Edmundson	✔			NYISO
A. Evans	✔			Department of Public Service
F. Francis	✔*			Brookfield Energy Marketing Inc.
G. Haake	✔*			Dynegy
K. Heinz	✔*			National Grid
B. Hurysz	✔			NYISO
S. Johnson	✔*			NYISO
D. Kaiman	✔			Brookfield Renewable Energy Marketing US LLC
M. Kramek	✔			Edison Mission Marketing and Trading
M. Lampi	✔			NYISO
S. Laroche	✔			Brookfield Renewable Energy Marketing US LLC
S. Leuthauser	✔			HQUS
R. Lim	✔			NYISO
R. Mackowiak	✔*			Entergy
N. Mah	✔*			Con Ed Solutions
G. McCartney	✔			Constellation Energy Commodities
J. Minalga	✔*			Invenergy LLC
T. Paynter	✔			NY Department of Public Service
R. Pike	✔			NYISO
M. Plante	✔			H.Q. Energy Services (U.S.), Inc.
D. Ramlatchan	✔*			Con Edison/O&R
D. Saia	✔*			Greenberg Traurig, LLP
M. Vadaga	✔*			Ventyx
J. Wadsworth	✔*			Vitol
S. Williams	✔			PJM
M. Younger	✔			Slater Consulting

* -- Indicates participated by telephone

Agenda Item #1: **OPENING REMARKS & MEETING OBJECTIVES**

The Chair of the NEPOOL Markets Committee welcomed the joint meeting participants and had the meeting participants including those participating by telephone identify themselves. The Chair then called upon Mr. Pike (NYISO) to begin the joint ISOs' presentation. Mr. Pike provided introductory remarks and an outline of today's presentations:

(1) The primary subjects for today's meeting will be the following:
  (a) Real-Time bids and schedules under the Coordinated Transaction Scheduling (CTS) option.
  (b) Day-Ahead External Transactions and linking them to Real-Time.
  (c) External Interface pricing and settlement.
  (d) Latency and price separation issues.

Mr. Pike stated that the purpose of these joint meetings is to discuss the joint ISO white paper options and to gather input from the stakeholders. Mr. Pike asked that stakeholders provide their written comments to him and Dr. White by next week. At this point in the presentation, the following question was asked:

(1) A meeting participant asked how do we provide comments by next week without having the benefit of fully discussing the complete subject. Net Commitment Period Compensation (NCPC) and other issues will not yet have been discussed by the two stakeholder groups. (ISOs: Mr. Pike replied that we are trying to get as much information as we can from the two stakeholder groups early in the process so we can respond to your concerns. We will certainly not foreclose questions or comments at future meetings and, to extent needed, we can use the fifth joint stakeholder meeting with an open agenda to address questions and concerns.)

Agenda Item #2: **SOLUTION OPTIONS: REAL-TIME SCHEDULING**

Mr. Pike presented the Solution Options: Real-Time Scheduling topic to the joint stakeholder meeting attendees:

(1) There are six key elements of the proposed Solution Options:
  (a) A new Real-Time Inter-Regional Interchange System (IRIS).
  (b) Higher frequency schedule changes (every 15 minutes).
  (c) Elimination of NCPC credits and debits and certain fees imposed on External Transactions.
  (d) Day-Ahead Energy Market External Transactions should remain similar to what is in place today under either solution option (other than as affected by congestion pricing).
  (e) Congestion pricing at the External Nodes will occur in both the Day-Ahead and Real-Time Energy Markets.
  (f) There will be Congestion Pricing hedging at the External Nodes (Financial Transmission Rights (FTRs) and Transmission Congestion Contracts (TCCs)).
(2) The design objectives for Real-Time interface scheduling are to:
  (a) Equalize LMPs at the interface at the time the schedule is set (this is much the same as today but today's system is not very effective at achieving equalization).
  (b) Update the Real-Time schedule as frequently as feasible (including any switch of direction in net flows).

(3) The two design options identified as having the greatest potential for efficiency improvement, both of which use the same economic dispatch are:
(a) Tie Optimization (TO)
(b) Coordinated Transmission Scheduling (CTS)

At this point in the presentation, the following points were raised:

(1) A meeting participant asked if these transactions would be firm transactions and how the required NERC Tags would be obtained.
(ISOs: Mr. Pike replied that the NERC Tags and the Available Transfer Capability (ATC) calculation would be performed just as they are today. The NERC Tags will be dynamic and will be updated as the interchange schedule changes. These scheduled would be firm interface schedules.)
(2) A meeting participant asked if this proposal would result in a shift in risk to loads away from traders.
(ISOs: Mr. Pike stated that there are a number of changes to risk profiles that we will be covering this afternoon. Certainly the risk profile will be different from what it is today for interface schedules but it will be closer to what is done with internal transactions.)
(3) A meeting participant said that we have this legacy system requiring a 75 minute advance schedule and NERC Tags for transmission. Are these processes which would need to be sped up or are they timing restrictions we have to live with?
(ISOs: Mr. Pike replied for some processes the answer is yes while for other processes the answer is no. NERC Tags will become more dynamic. In both options (TO and CTS) the timing issues are the same as we move as close as possible to 15 minutes. We do not expect these timing issues to limit either proposed option.)

Mr. Pike resumed his presentation:

(1) A review of the graph (on slide 10) showing Optimal Tie Schedule without Total Transfer Capability (TTC) limits shows that, in this scenario, the external LMP for both Control Areas is the point where the two supply stacks cross. LMP^{EXT} represents the proxy price in both ISOs.
(2) A review of the graph (on slide 11) showing Optimal Tie Schedule with binding TTC limits shows that there are two proxy prices LMP^{NY} and LMP^{NE}. We would still have LMP^{EXT} which is set at the midpoint between the two proxy prices. In the example this remains the point at which the supply stacks cross but with a binding TTC they would not cross. These prices are used to allocate congestion costs across the interface between the two ISOs.

At this point in the presentation, the following points were raised:

(1) A meeting participant said he did not quite understand how LMP^{EXT} (the midpoint between the New York and New England LMPs) is utilized.
(ISOs: Mr. Pike replied that in this scenario, we have a price separation on the system and a congestion rent. Half of this congestion rent accrues in the New York market and the other half in the New England market. If this occurs in the Day Ahead Energy Market, then this will need to be paid out to FTR holders, if it occurs in the Real-Time Energy Market, then distribution will need to follow each control area's tariff provisions. The purpose of setting

the LMP^{EXT} at the midpoint is to say half the congestion rent occurs in each control area for cost allocation within the two ISOs.)

(2) A meeting participant asked if the incremental cost curves should be adjusted by the uplift that is paid for the generators running out of merit to address these hidden costs.
(ISOs: Mr. Pike answered that the interface is always scheduled on marginal cost. Each ISO, in making its commitment and dispatch decisions, includes the costs you are talking about.)
The meeting participant said he was thinking about a committed unit that receives uplift in New England that has not reached its minimum generation or is otherwise dispatched uneconomically.
(ISOs: Mr. Pike replied that the Dispatch software already includes minimum generation so that would be reflected in the supply stacks. If a unit was brought on-line for a specific problem, more coordination would be required and more options could be available. If the unit was brought on out of merit both control areas would know that the unit was on as well as the reason why.)
The meeting participants asked if the whole three part supply curve needs to be looked at.
(ISOs: Mr. Pike replied yes.)

(3) A meeting participant asked is it fair to say the supply stacks are only those generators with capacity commitments. How about Demand Resources?
(ISOs: Mr. Pike replied resources in the supply curves are any resources that are in the Energy Markets for dispatch. This is the same resource mix as for any other purpose.)
The meeting participant asked if the ISOs will see multiple parallel curves.
(ISOs: Mr. Pike replied yes. Each curve is a snapshot in time. These curves are also likely to have step functions and not quite the smooth curve depicted based on resource availability.)

(4) A meeting participant said that the proposal seems to be adding together the New York and New England supply stacks, which should decrease lumpiness and therefore decrease the uplift amount.
(ISOs: Mr. Pike answered that is correct. The objective is to increase the amount and response (i.e., reaction in Real-Time) of resources available to meet requirements in both markets.)

(5) A meeting participant asked whether LMP^{EXT} really should be at the midpoint in all cases. Should there be some sort of weighting to determine LMP^{EXT}?
(ISOs: Mr. Pike replied we show it as the midpoint for simplicity. A 50/50 split seems equitable in most cases given that the quantity of flows in each direction is roughly equal over time. If there were a reason to set it somewhere other than at the midpoint we could do so.)

(6) A meeting participant asked is it possible to figure out what the LMP^{EXT} would be. If so, why set it at the midpoint between LMP^{NY} and LMP^{NE}?
(ISOs: Mr. Pike stated that there are no limits to what we could do in modeling and determining the appropriate split. This graph (on slide 11) shows a calculation that looks solely to the congestion at the interface (and not internal constraints) and net schedules flow roughly equally back and forth. We see very rare instances where these ties will be constrained so there is relatively little money at stake. A 50/50 split seemed to be an equitable sharing given the relatively low dollar amounts to be captured and the complexity and cost of modeling.)
The meeting participant stated while that may be true today, we should design this project to measure what is really occurring in the markets.
(ISOs: Dr. White replied that there are a number of ways to do this and several of them are worth considering.)

(7) A meeting participant said that the market design should not be for what exists now but should be for how it might be under the new arrangements.

(8) A meeting participant asked for clarification of what the pool of money being divided consists of.
(ISOs: Mr. Pike replied this pool money is the total amount collected versus what is paid out in the Energy Market. There are congestion revenue funds in both of the ISOs that they distribute as congestion revenue residuals or shortfalls. This 50/50 split or some other split determines how much interface congestion revenue gets distributed/charged as part of the residuals or shortfalls by the two ISOs.)

Mr. Pike continued his presentation with a discussion of the CTS option:

(1) This option would introduce Real-Time interface bids for both ISOs (a simultaneous bid to buy and sell across the interface) and would consist of the following:
(a) A single common transaction in both control areas (no check-out).
(b) Can submit multiple bids (price-quantity-direction triplets),
(c) Can submit for any block of 15 minute intervals (clear every 15 minutes).

(2) There would be coordinated clearing (scheduling) in Real-Time.

At this point in the presentation, the following points were raised:

(1) A meeting participant asked at what time do you lock in the schedule.
(ISOs: Mr. Pike replied that we will be discussing the timeline later in the presentation that will address your question.)

(2) A meeting participant asked if it would be fair to say these interface bids act as a proxy for looking at the Supply Offers in the supplying ISO.
(ISOs: Mr. Pike answered the supply stacks represent an aggregate of available resources that can move power to the border. An interface bid merely captures the difference between the two supply stacks.)

Mr. Pike continued his presentation by reviewing three additional graphs:

(1) The first graph reviewed (on slide 23) depicts a situation where we would have price separation but no congestion at the border. In this scenario, interface bids scheduled would be paid the difference between the two supply stacks.

(2) The second graph (on slide 26) depicts a situation where there are two prices because of TTC (i.e., congestion on the interface to be captured in clearing prices).

(3) The third graph (on slide 27) depicts congestion (midpoint between LMP^{NY} and LMP^{NE}) and interface bids limited by the TTC. In this scenario we would end up with two external LMPs ($LMP^{NY\text{-}EXT}$ and $LMP^{NE\text{-}EXT}$) showing the congestion cost of the system limitation and the price separation based on the interface bids.

Mr. Pike then presented the distinctions between the TO and CTS options:

(1) The optimization steps to determine the desired interchange schedule are functionally identical between CTS and TO.

(2) The resulting interchange schedule will be different under CTS than under TO if the interface is not limited by TTC constraints.

At this point in the presentation, the following points were raised:

(1) A meeting participant asked if 1200 MW were to be scheduled in each direction is the result for CTS the same as for TO.
(ISOs: Mr. Pike answered if the interface bids were all zero, yes. The smaller the interface bids the closer the result of CTS is to the result of TO. Slide 29 illustrates that the incorporation of interface bids is the major difference between these options in terms of establishing the schedules.)
The meeting participant asked if all interface bids are zero what priority is given to competing schedules.
(ISOs: Mr. Pike replied the results would be determined on a pro rata basis.)
(2) A meeting participant asked if this proposal was roughly equivalent to performing Real-Time dispatch from both of the ISOs as if there was a Self-Schedule or fixed price quantity pair from one control area to the other for a 15 minute period.
(ISOs: Mr. Pike answered that under either option we would see a stack of resources available for dispatch in NY.)
The meeting participant asked if New England would see a single price.
(ISO: Mr. Pike replied that New England would provide New York a series of price quantity pairs at various levels of import that would be added to the New York dispatch as another resource.)
The meeting participant asked will you will pick a quantity for 15 minutes to set the tie schedule.
(ISOs: Mr. Pike answered yes. There is a 15 minute lag between the schedule and dispatch to be known as latency risk and that topic will be covered later today.)
(3) A meeting participant asked what happens when the price forecasts for the next 15 minutes are different from the actual prices. Was that considered in estimating the gains from making this change?
(ISOs: Mr. Pike answered yes, it was considered in Potomac Economics' analysis.)
The meeting participant stated that it would be good to hear from Potomac Economics again on how they evaluated accuracy of forecast given the risk allocation to those Market Participants stating "take my interface bid if the price differential is a certain amount".
(4) A meeting participant expressed concern about the use by the ISOs of information not available to the public. Why not just post the information and not conflict with what the power plants are doing? He suggested this proposal amounted to the ISOs entering the market as buyer and seller.
(ISOs: Mr. Pike replied that the two ISOs do not see this as different from what we are doing today in dispatching based on offers and bids. Which option are you focusing on?)
The meeting participant replied the concern is that if I tell you what I will do in an hour and you act on that information in a 15 minute timeframe my incentive is not to provide the hourly information to the ISO.
(ISOs: Mr. Pike stated that all these schedules are snapshots in time. We see this process as requiring more and not less communication.)
The meeting participant stated the ISO does not post that information so the market could respond perhaps faster and better if the information was posted. The ISO can do this by

acting on confidentially provided information that precludes the Market Participant from optimizing its resources to retain the profit.
(ISOs: Mr. Pike responded that we believe we have proved with internal dispatch that the ISO can perform the interchange schedule more efficiently. Also, this is dispatch of units and not a market activity. We do not see this outcome being any different other than it will be a more coordinated dispatch of Market Participants' market based offers to achieve the goals stated.)

(5) A meeting participant asked when does the market for interface bids close.
(ISOs: Mr. Pike answered at 75 minutes in advance just like all other External Transaction offers/bids in the NYISO.)

(6) A meeting participant asked where the materials for today's meeting were posted.
The Chair replied they are posted with ISO-NE's Markets Committee materials and a link was also posted on the NYISO web site.
The meeting participant said his company is against this type of proposal in the Midwest ISO and agrees with PJM's position. He went on to say his company is likely to be against this proposal in the NYISO.

(7) A meeting participant asked how do we get to a decision on which option the ISOs will include in a Design Basis Document (DBD).
The Chair replied there is likely to be a DBD including both options and we would then have two votes (one in each ISO) on which option to pursue.
The meeting participant asked is it fair to say that the ISOs believe both options can be done and they do not have a preferred option.
(ISOs: Dr. White stated yes to the first question and no to the second question. Both of these options are better than what we have today; however, the ISO staffs prefer the Tie Optimization option, which better mimics least cost economic dispatch and is more efficient than the Coordinated Transaction Scheduling option. Because the results are behavior driven we do not know how much more efficient the TO option would be versus the CTS option.)
The meeting participant asked if the stakeholders in either ISO choose CTS will the ISOs oppose that choice.
(ISOs: Dr. White replied from a broad perspective our intent is to present the two options to the two stakeholder groups. If we hear all stakeholders speak with one voice, it is likely the ISOs would not oppose that voice; however, ISO-NE/NYISO staff cannot speak for ISO-NE Board of Directors or NYISO's Board of Directors. We also cannot predict the ISOs' response before we have heard from the two stakeholder groups. The ISOs believe both options are substantially better than what we have in place today; however, the TO option will run the grid more efficiently than the CTS option. As the efficient operation of the grid is a core function of both ISOs, we recommend the TO option. If there is significant division among stakeholders, we cannot say how the ISOs' Boards and Management will proceed.)

(8) A meeting participant asked what are the business analysis results of these two options. How much is saved at what cost?
(ISOs: Dr. White replied that Potomac Economics (External Market Monitor for ISO-NE and Market Monitor for NYISO) spent more than 40 minutes at our first meeting on that subject. In summary, implementation costs are not yet known but would likely be in the single digit millions of dollars. Conservatively (based on pure efficiency gains) this proposal would provide tens of millions of dollars in benefits with a payback period for the cost incurred that may be as low as approximately six months.)

(9) A meeting participant said that one of the current market inefficiencies is transaction costs. What would be the process for eliminating any remaining Schedule 1 costs?

(ISOs: Mr. Pike responded that there are two different cost categories. The costs of running the system do not go away but may be re-allocated if they interfere with capturing larger efficiency gains. We want to use all information provided to the ISOs to optimize these schedules and capture any efficiency gains. The ISOs have proposed eliminating the costs on schedules to each other on a reciprocal basis.)

(10) A meeting participant said he was concerned that these options are taking place in Real-Time while most unit commitment is accomplished Day-Ahead. This leads to less participation in the Day-Ahead Energy Market, less efficient unit commitment, and more uplift. If you cannot figure out how to use this proposal in the Day-Ahead Energy Market, the control areas may end up with higher prices in the Day-Ahead Energy Market rather than in the Real-Time Energy Market since the Real-Time Energy Market is being optimized. The FTRs and TCCs will be calculated inappropriately.
(ISOs: Dr. White replied that the ISOs disagree with your statement. We could explore performing a coordinated Day-Ahead unit commitment if that is desired by stakeholders but the statement that Real-Time coordination would have deleterious impacts on the Day-Ahead Energy Market is puzzling. We do not see it and suggest we have more discussion outside of this meeting. We hear your strong views on this issue and we would like to better understand the basis for them.)

<u>Agenda Item #3:</u> <u>**DAY-AHEAD EXTERNAL TRANSACTIONS**</u>

Dr. White presented the Day-Ahead External Transactions topic to the joint stakeholder meeting attendees:

(1) The ISOs received a number of specific requests on how Day-Ahead External Transactions would work and how they relate financially to Real-Time for the two proposed options:
  (a) Day-Ahead External Transactions would work very much like today unless there is congestion at the external interface.
  (b) Day-Ahead External Transactions can flow through to Real-Time for settlement purposes.
  (c) The process to flow through into Real-Time should be as easy or easier to achieve when compared to today's market.

At this point in the presentation, the following point was raised:

(1) A meeting participant requested, given that the Day-Ahead Energy Market is both a financial market and the basis of a large percentage of unit commitments, that the ISOs address how these External Transactions are (in the current markets) and will be (under these proposals) dealt with in the Resource Adequacy Assessment (RAA) process.
(ISOs: Dr. White replied that we will try to address that subject in a later meeting.)

Dr. White then summarized how Day-Ahead External Transactions work today:

(1) New York and New England Day-Ahead Energy Markets clear separately and at different times of the day. This would not change under either proposed option.
(2) The examples presented in today's presentation exclude congestion for simplicity. Congestion and FTRs will be reviewed at the upcoming March 7 joint stakeholder meeting.
(3) New York and New England Day-Ahead Energy Markets clear separately at different prices and in different amounts because:

(a) Market Participants can and do submit different offers to the two markets.
(b) All external transaction offers clear against internal offer stacks that are different in New York and New England.

At this point in the presentation, the following points were raised:

(1) A meeting participant asked whether the separate clearing against different offer stacks would create an incentive not to bid load in the Day-Ahead Energy Markets.
(ISOs: Dr. White replied that we would need to study the stated scenario to provide a definitive answer. We have not come across any but would need to do more rigorous analysis before answering that question.)
(2) A meeting participant (referring to the example presented on slide 42 of the presentation) asked whether the two generators that were not committed Day-Ahead could then be committed out of merit in Real-Time.
(ISOs: Dr. White answered they could be.)
The meeting participant asked would that impact the Tie Optimization option in Real-Time.
(ISOs: Dr. White answered yes.)
(3) A meeting participant asked are we committing to staying with a single tie model (Roseton).
(ISOs: Dr. White answered no. We will be looking periodically at how to define proxy buses, now and in the future.)
(4) A meeting participant said that the response to a previous question (see item (2) above) seemed to imply that a Demand Bid that cleared in the other control area was exported and, presumably, would be replaced by generation that would increase the LMP in the exporting control area. Who controls whether this goes forward and can flow?
(ISOs: Dr. White answered there is no coordination between control areas regarding these markets. Each Day-Ahead Energy Market runs completely separately.)
The meeting participant replied therefore in the Day-Ahead Energy Market a resource could be from outside of the control area as long as it is offered and clears. It appears you do not care what results in Real-Time.
(ISOs: Dr. White replied that we cannot say we do not care what happens in Real-Time. We look at what is available in the Day-Ahead Energy Market for New England and apply our standard clearing rules.)

Dr. White returned to his presentation:

(1) Day-Ahead External Transactions are handled in the same manner as today except that the congestion cost component may be slightly different.
(2) Day-Ahead External Transactions tend to reduce LMP difference between regions, but not completely.
(3) Day-Ahead External Transactions can clear different amounts (this does not occur in Real-Time because of the check-out) and at different prices in the two markets.
(4) The most often asked question we received since the last meeting is how does a Market Participant avoid Real-Time energy balancing (deviation) charges.
    (a) Under CTS: (1) submit and clear a matching Interface Bid in RT, (2) interface bids are submitted to a common portal, not separately to each ISO, and (3) clearing of interface bids is economically coordinated by both ISOs to set the Real-Time interface schedule.

Dr. White then reviewed several examples under CTS from the perspective of "Participant G" (see slides 46 through 52). After the discussion of these examples, the following points were raised:

(1) A meeting participant asked if we look at the situation today, if a schedule flowed for the amount that cleared in the Day-Ahead Energy Market in New England there would be no deviation but, if not, there would be both deviation in the market plus NCPC for deviating from the Day-Ahead schedule. Would this occur in New York as well under today's rules?
(ISOs: Mr. Pike answered no.)
The meeting participant asked are deviations allocated to Network Load in New York.
(ISOs: Mr. Pike replied deviations are allocated to all extractions from the system including exports to all Real-Time withdrawals but not to imports.)

(2) A meeting participant asked in New England are exports also subject to deviation from the Day-Ahead schedule.
(ISOs: Dr. White answered yes.)
The meeting participant asked for confirmation that there are already differences between the two control areas that cause inefficiencies.
(ISOs: Dr. White answered yes. That is the reason why we are proposing to eliminate those deviation charges. We will be discussing that subject in more detail at the March 7 joint stakeholder meeting.)

<u>Agenda Item # 4 **DAY-AHEAD AND REAL-TIME MARKET LINKAGES**</u>

Dr. White presented the Day-Ahead and Real-Time Market Linkages topic to the joint stakeholder meeting attendees. Dr. White provided the following three observations; (1) a Market Participant does not need to have a Day-Ahead position to submit an interface bid; (2) the lower the interface bid is, the more likely it is to clear; and (3) there is consideration being given to allowing negative interface bids. Dr. White stated currently, if a Market Participant clears Day-Ahead in only one market that Market Participant will have a Real-Time debit/credit in at least one Real-Time Market. That statement remains true under the two proposed options. Otherwise accounts would not balance. At this point in the presentation, the following points were raised:

(1) A meeting participant asked for more information about the potential for negative bids.
(ISOs: Dr. White replied we believe that negative bids could help ensure certain transactions flow but they carry a risk of the negative bid clearing at a high cost to the bidder. We think that is not likely to happen more than once given the economic incentives.)

(2) A meeting participant asked if there was any reason not to allow negative bids.
(ISOs: Dr. White answered yes.)
The meeting participant asked would you protect me if I bid the lowest (most negative) bid you allow to honor my Day-Ahead schedule.
(ISOs: Dr. White stated you are asking if we would charge others to preserve your right to make money.)
The meeting participant replied not exactly.
(ISOs: Dr. White responded that it sounds like you are articulating a reason that it is in your business interest to have negative bids.)
The meeting participant stated if I have a Day-Ahead schedule and I bid the lowest interface bid available and I end up not clearing and the flow actually moves in the opposite direction

(i.e., ISOs' forecast is incorrect and will not flow in the Real-Time) I do not believe I should be charged because I do not have the ability to bid a negative bid.
(ISOs: Dr. White stated we are not fundamentally opposed to negative bids. We have not come to a conclusion as to whether to recommend negative bids.)

(3) A meeting participant asked for the reason for not allowing negative bids.
(ISOs: Dr. White replied if we have only negative bids and in large amounts that could set the tie schedule to flow in the wrong direction and that defeats the purpose of doing this project. As we said earlier, assuming no NCPC or other fees we would expect the market to respond and to turn the flows in the economically "right" direction. If we cannot address NCPC then potentially negative bids should not be allowed because that may continue the counter intuitive flows.)

(4) A meeting participant said that many loads do not want to assume Real-Time risk or the risk of ISO forecast errors. He said he saw no reason to prohibit negative bids to hedge these risks.

(5) A meeting participant said the discussion today seems to be pointing to NCPC as the root of several problems. Perhaps we should try to address the NCPC subject. Even if you keep NCPC risk in place, the design should allow negative bids down to negative $1000. NCPC would then be highlighted as the source of the misallocation of costs.

(6) A meeting participant asked how are these interface bids dealt with in settlements. If these are only to ensure clearing, he did not see why anyone would bid above the lowest allowable amount (i.e., zero).
(ISOs: Dr. White replied these bids serve two purposes: (1) to lock in a Day-Ahead position, a participant might bid as low as it is able; (2) a participant may have no Day-Ahead position and will bid to obtain the real-time price difference. There are risks to the second purpose of submitting a negative bid. Post-offer contingencies can result in gains or losses of large dollar amounts. Interface bids above zero can be an important risk mitigation strategy for some Market Participants, and we do not know your business plan or what your risk mitigation officers will set as limits on this kind of activity. You are always at risk of being displaced by a more aggressive competitor.)

(7) A meeting participant pointed out that, recently, errors in implementing a joint operating agreement between two ISOs were billed to Market Participants and this proposal seems to have many more bells and whistles than that arrangement.
(ISOs: Dr. White replied Market Participants are relying on these two ISOs to settle billions of dollars in these markets. We have extensive protocols to prevent errors, but cannot assure you of perfection or omniscience. We also cannot comment on a MISO/PJM matter that we are not parties to.)

(8) A meeting participant asked if there would be a need for increased collateral under CTS.
(ISOs: Dr. White answered it is not yet known whether more collateral would be needed or if any other changes in financial assurance arrangements might be needed. Financial assurance issues would be addressed during the implementation stage.)

(9) A meeting participant asked about the timing for the NYISO posting of prices.
(ISOs: Mr. Pike replied it would be the same timing as in today's market.)

(10) A meeting participant asked whether doing away with NCPC and more frequent scheduling of the interface was looked at as an option.
(ISOs: Dr. White replied we recommend eliminating NCPC on externals, yes.)
The meeting participant clarified that he was asking if the ISOs had considered applying neither of its two options but, instead to just allow 15 minute scheduling and remove NCPC on External Transactions.

Dr. White resumed his presentation by presenting the Tie Optimization examples, again from the perspective of "Participant G" (see slides 57-59 of the presentation). Dr. White pointed out that all paired Day-Ahead Energy Market offers (i.e., those that cleared both markets) will flow through to Real-Time for settlements, which should help avoid Real-Time balancing charges. At this point in the presentation, the following points were raised:

(1) A meeting participant asked if these transactions would still need transmission tags. (ISOs: Dr. White answered yes they do, however, there are a number of ways we can handle that subject including ties to the NEPOOL Generation Information System.)
(2) A meeting participant asked what if net Real-Time flows are opposite. (ISOs: Dr. White replied for settlement purposes we would, for example, treat DA schedule of 1000 MW east and a real-time scheduled flow of 1600 MW west as a net schedule of 600 MW west in real-time settlements. This is addressed in Agenda Item #5.)

Agenda Item #5: **INTERFACE SETTLEMENTS**

Dr. White presented the Interface Settlements topic to the joint stakeholder meeting attendees:

(1) ISO-Level Settlements.
    (a) Tie Optimization is designed to model between ISO settlements the same way as existing within ISO settlements.
    (b) Within one ISO; if the ISO increases generation in Massachusetts to meet load in Connecticut the ISO is not buying or selling power by doing so.
    (c) The ISO is, as a settlement agent, allocating revenues from loads in one location to generators that were increased in output to meet load.
    (d) The ISOs must ensure that the generator in one Control Area that is increased in output to meet load in the other Control Area is paid its LMP, just as in the one ISO example.
(2) Several ISO-Level Settlement examples under Tie Optimization were presented.
(3) Price separation under Tie Optimization can still occur for two reasons:
    (a) Unexpected system changes (e.g., generator trip during the latency time lag from schedule to actual dispatch, but this is cut to 15 minutes or less from about an hour under the current rule).
    (b) Real-Time congestion if TTC becomes a binding constraint, which is passed through as real-time congestion revenue (and can be positive and negative).

Dr. White then presented an example using CTS and interface bids (slides 71-73 of the presentation):

(1) Interface bids clear a net Real-Time schedule of 100 MW from New York to New England.
(2) CTS sets the ISO-NE Real-Time LMP to $53 and the NYISO Real-Time LMP to $51.
(3) Day-Ahead External Transactions cleared 1000 MW from New York to New England.
(4) NYISO Real-Time Settlement:
    (a) Interface bidders with Day-Ahead positions have no Real-Time charges.
    (b) Interface bidders without a Day-Ahead position are charged at the NYISO Real-Time LMP of $51.
(5) ISO-NE Real-Time Settlement:

(a) Interface bidders without a Day-Ahead position are paid at the ISO-NE RT LMP.
(b) Internal generation with downward instructed deviations from Day-Ahead position are charged at the Real-Time LMP.
(c) This results in interface bidders without a Day-Ahead External Transaction having a $5300 Real-Time credit (100 multiplied by ISO-NE Real-Time LMP of $53).

(6) There is a Real-Time net gain of $200 to Interface Bidders without a Day Ahead position across the two markets (NYISO: 100 MW times $51 = $5100; ISO-NE: 100 MW times $53 = $5300; $5300 - $5100 = $200).

At this point in the presentation, the following question was raised:

(1) The meeting participant stated the interregional account may affect many generators and the interfaces with other control areas. How do generators get paid and how do loads pay? (ISOs: Dr. White replied in the same manner as they do today. We will know what resources were dispatched up or down, the applicable LMPs, and how deviations settle in each control area.)

Agenda Item #6: **LATENCY AND PRICE SEPARATION**

Mr. Pike presented the Latency and Price Separation topic to the joint stakeholder meeting attendees:

(1) Latency is the delay between when the interface schedule is set and when the power flows.
(2) There are surpluses and deficiencies associated with latency where there is a difference in prices between the time a schedule is set and the time the power flows.
(3) This can lead to expected LMPs being different from actual Real-Time LMPs.
(4) Under today's rules:
    (a) Uplift payments would occur where an export clears at $50 but in Real-Time a generator trip causes the price to be $150 for the hour.
    (b) At settlement, the Real-Time exports pay $150 but receive a make-whole payment for $100.
    (c) Real-time make whole payments are charged as uplift, primarily to load in New York and to deviations in New England.

At this point in the presentation, the following points were raised:

(1) A meeting participant asked if this uplift payment was limited to imports. (ISOs: Mr. Pike replied in NYISO the uplift payment is limited to imports only. In ISO-NE it is both imports and exports.)
(2) A meeting participant asked if there was different treatment for capacity transactions. (ISOs: Mr. Pike answered no.)

Mr. Pike resumed his presentation:

(1) Can IRIS reduce latency risk? Yes. The 15 minute scheduling and offsetting impacts under the Tie Optimization option (flows to same parties) can reduce latency risk.

At this point in the presentation, the following points were raised:

(1) A meeting participant asked if the offsetting refers to the congestion revenue fund collected. (ISOs: Mr. Pike answered no. The point is that the impacts accrue to the same Market Participants whether they are positive or negative. The impact is not assigned to others as uplift.)

Mr. Pike presented examples of latency under the Tie Optimization and CTS options (slides 78-84 of the presentation). At this point in the presentation, the following points were raised:

(1) A meeting participant expressed concern about the offsetting latency impacts not getting reflected in the LMPs under the TO option.
(ISOs: Mr. Pike responded that we have turned up generation but continue to pay the generator $50 while load in the TO option pays $150 in the example. The $100 would be allocated to all loads. So the LMPs did capture the cost but we have over-collected revenues to be allocated out.)
(ISOs: Dr. White stated if the Tie Optimization sets a single price for the next 15 minutes, however, a generator trips 5 minutes into the 15 minute period, there could be a charge. But under Tie Optimization we can have the opposite where the generation trip spikes price upward in the importing region and we end up with surplus/credit to uplift. Overall, Tie Optimization should decrease the amount of uplift from today, because the ties reset faster and any price separation in Tie Optimization will tend to have offsetting impacts that can reduce uplift costs.)
The meeting participant asked are you thinking of allocating uplift charges and credits in more or less the same way as today's charges.
(ISOs: Dr. White answered yes, because we have no desire to wade into new cost allocation discussions at this time.)

(2) A meeting participant said that the CTS option at a zero bid has the same result but provides an option to take on risk shifting through non-zero bids.
(ISOs: Dr. White replied if CTS bids are being entered without a Day-Ahead position Market Participants will probably need to charge a risk premium or they would be offering to buy and sell at the same price.)
The meeting participant replied that in the TO option you are forcing load to take those positions rather than back out and let traders set a price with a risk premium.
(ISOs: Dr. White stated that with CTS we would not have the same LMPs in both regions and therefore the ISOs are not running markets efficiently, and are producing LMPs where buyers are paying too much for every MWh. The problem is that this risk premium impacts the LMPs for both markets 8760 hours per year. Uplift to specific resources is nothing compared to the higher LMP value to be paid by load on an annual basis.)
The meeting participant replied that load can still do this for themselves with zero bids and keep traders' bids from clearing by choosing to take the risk. The TO option forces the risk on buyers that have no opportunity to opt out. The CTS option provides load a free option to opt out so why not eliminate TO right now?
(ISOs: Dr. White answered we hope our arguments for the TO option were clear. In the interest of time we need to move on but we are willing to continue this discussion off-line.)

(3) A meeting participant asked when the LMPs fail to converge between the two ISOs; then there is an inter-ISO settlement account (see slide 82, bullet 2). Do you expect these latency

amounts to switch between the two ISOs? What do we do with the money? Do the ISOs place the surplus into the inter-ISO settlement account and settle at end of each year or what? (ISOs: Dr. White replied this subject is treated essentially as Real-Time NCPC (both positive and negative). Identifying who pays for the "make whole" payments where prices do not converge would, if we stay with today's system, work just as it does today. We are open to different ways of doing this but the core issue is the same as today. Tie Optimization does cut the time duration and thus the dollar amounts at risk.)
The meeting participant asked if the benefit is that the shorter scheduling period reduces uplift even though some uplift continues.
(ISOs: Dr. White answered yes; plus the benefits of getting the right units on the margin and having the flow on the ties move in the right direction.)

(4) A meeting participant stated Potomac Economics focused on production cost savings rather than energy savings.
(ISOs: Dr. White answered yes. The tens of millions mentioned earlier were the production cost savings not the total energy market savings.)
The meeting participant asked what about the statements about LMPs for 8760 hours.
(ISOs: Dr. White replied that he was referring to energy savings but that was a response to a comment about risk allocation to loads.)
The meeting participant expressed concern that there is a relatively small difference in the two options and the ISOs may be stepping into a function that is currently performed by Market Participants.
(ISOs: Dr. White responded that it is the ISO's job to recommend the most efficient market design. There may be a strong opinion of Market Participants in favor of one option or the other, but we recommend the more efficient option.)

(5) A meeting participant asked how are you getting production cost for a 15 minute period. How does this create efficient commitment? This proposal seems to be optimizing the energy price. There is no time to commit longer lead time larger units.
(ISOs: Dr. White agreed that this is about optimizing the energy dispatch. We have not yet presented any commitment process changes that could flow from this project.)

(6) A meeting participant asked why the ISOs cannot design this effort for every 5 minutes like the internal markets economic dispatch.
(ISOs: Mr. Pike replied right now we believe 15 minutes is the best we can do technically on this coordination, given current system capability and technology. We are not opposed to shortening the timeframe later when we can.)

(7) A meeting participant asked why not 15 minutes ahead on a rolling 5 minute basis.
(ISOs: Mr. Pike answered the NYISO dispatch look-ahead function is on a fixed 15 minute basis right now. A rolling basis would not sync up with the NYISO real-time commitment process.)

(8) A meeting participant asked if the ISOs would bring back some actual numbers on latency values.
(ISOs: Mr. Pike responded that we will take that request back and discuss it at a future joint stakeholder meeting; but probably not by the next meeting where the agenda is already full.)

Mr. Pike resumed his presentation by pointing out two remaining issues:

(1) The CTS approach may not yield sufficient interface bids to optimize the interface.
(2) We would need inter-ISO accounting for the TO approach.

Agenda Item #7: **MEETING SUMMARY AND NEXT STEPS**

Mr. Pike summarized the schedule going forward:

(1) As mentioned earlier, written questions and comments are requested by February 22, 2011.
(2) The remaining joint stakeholder meetings will be focused on:
    (a) Understanding the options in detail.
    (b) Gathering feedback.
    (c) Refining the input into a preferred Design Basis Document by April-May of 2011.
    (d) The ISOs need a common DBD on IRIS due to coordination issues.
(3) The schedule of joint stakeholder meetings is as follows:
    (a) March 7, 2011 ISO-NE hosting at the Springfield Sheraton
    (b) March 28, 2011 NYISO hosting
    (c) April 28, 2011 NYISO hosting
(4) The items to be presented at the meetings are as follows:
    (a) March 7: FTRs and congestion, NCPC, fee recommendations, and conforming capacity rule changes.
    (b) March 28: Q&A, follow-up, additional detail as requested, and stakeholder discussion on a draft DBD.
    (c) April 28: Q&A, follow-up, additional detail as requested, stakeholder discussion of draft DBD.
(5) After these joint stakeholder meetings:
    (a) April-May 2011: Advisory votes on design options (DBD) from both NEPOOL and NYISO stakeholders.
    (b) June-October 2011: Stakeholder tariff and Market Rule processes (separate but with parallel timing).
    (c) December 2011: Target date for FERC filings.
    (d) Spring 2013: Estimated implementation date.

NEXT MEETING

The next meeting of the Joint NEPOOL Markets Committee/NYISO Market Issues Working Group is scheduled to be held on March 7, 2011 at the Sheraton Hotel in Springfield, MA.

Respectfully submitted,

______/s/____________

Alex W. Kuznecow
Secretary
Markets Committee