MINUTES OF THE
JOINT NEPOOL MARKETS COMMITTEE/NYISO MARKET ISSUES WORKING GROUP MEETING
HELD ON MONDAY, MARCH 7, 2011
IN SPRINGFIELD, MASSACHUSETTS

NEPOOL Markets Committee

Attendee	3/7		Member/ Alternate	Market Participant
A. DiGrande	✓		Chair	ISO New England Inc.
E. Abend	✓*		Member	Summit Hydropower, Inc.
			Alternate	Enbala Power Networks Inc.
D. W. Allegretti	✓		Alternate	Constellation Energy Commodities Group, Inc.
B. Bleiweis	✓		Member	DC Energy, LLC
N. Bosse	✓		Member	Brookfield Energy Marketing, Inc.
C. A. Bowie	✓*		Member	Northeast Utilities Service Company
			Temporary Alternate	NSTAR Electric Company
T. J. Brennan	✓		Member	New England Power Company
N. Chafetz	✓		Temporary Alternate	Customized Energy Solutions for BP Energy Company, Constellation Energy Commodities Group, Inc., 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
K. Dell Orto	✓*		Member	Generation Sector Provisional Group Member
			Alternate	Millenium Power Partners, LP
M. A. Erskine	✓*		Alternate	Central Maine Power Company
F. Ettori	✓		Member	Vermont Electric Power Company, Inc.
W. Fowler	✓*		Member	Exelon New England Holdings, LLC and Granite Ridge Energy, LLC
			Alternate	Dighton Power, LLC
			Temporary Alternate	Entergy Nuclear Power Marketing LLC
P. Fuller	✓		Member	NRG Power Marketing, LLC
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.
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
W. G. Ryan	✓*		Alternate	Vermont Electric Power Company, Inc.
P. C. Smith	✓		Member	GenOn Energy Management, LLC
P. P. Smith	✓		Member	Northeast Utilities Service Company
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
M. Brewster	✓			ISO New England Inc.
R. Coutu	✓			ISO New England Inc.
B. D'Antonio	✓*			MA DPU
J. Dombrowski	✓			ISO New England Inc.
J. Douglass	✓			ISO New England Inc.
J. Dwyer	✓			ISO New England Inc.
R. Ethier	✓			ISO New England Inc.
E. Jacobi	✓			CT DPUC
C. Mendrala	✓			ISO New England Inc.
J. Scalabrini	✓			ISO New England Inc.
S. M. Sciarrotta	✓			Vermont Electric Power Company, Inc.
M. White	✓			ISO New England Inc.

* -- Indicates participated by telephone

NYISO Market Issues Working Group				
Attendee	**3/7**			**Organization**
A. Ackerman	✓*			Customized Energy Solutions
G. Bissell	✓			Couch White, LLP for Multiple Intervenors
M. Bowman	✓*			NYSDPS
R. Boyle	✓			NYPA
J. Brodbeck	✓*			Coral Power LLC
C. Brown	✓*			NYISO
J. Buechler	✓*			NYISO
L. Bullock	✓*			NYISO
M. Cadwalader	✓*			Atlantic Economics LLC
P. Caletka	✓			NYSEG
T. Chan	✓*			Central Hudson
D. Clarke	✓*			Long Island Power Authority
D. Congel	✓			TC Ravenswood, LLC
P. Edmundson	✓			NYISO
S. Englander	✓			Charles River Associates
A. Evans	✓*			NY Department of Public Service
F. Francis	✓*			Brookfield Energy Marketing Inc.
H. Fromer	✓*			PSEG Power NY
J. Gredder	✓*			National Grid
B. Hurysz	✓			NYISO
M. Kramek	✓*			Edison Mission Marketing and Trading
M. Lampi	✓*			NYISO
R. Lim	✓			NYISO
S. Leuthauser	✓*			HQUS
N. Mah	✓*			Con Ed Solutions
R. Mancini	✓*			Customized Energy Solutions
G. McCartney	✓*			Constellation Energy Commodity Group
J. Morris	✓*			PACE
R. Mukerji	✓*			NYISO
T. Paynter	✓*			Department of Public Service
R. Pike	✓			NYISO
D. Ramlatcham	✓			Consolidated Edison Energy, Inc.
R. Raja	✓*			Viridity Energy Inc.
D. Saia	✓*			GenOn Energy Management, LLC
D. Weghorst	✓*			PPL EnergyPlus LLC
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 proceeded to call the meeting participants' attention to the joint memorandum authored by the Chairs of the NEPOOL Markets Committee and NYISO Market Issues Working Group and the Vice-Chair of the NEPOOL Markets Committee which addresses the Inter-Regional Interchange Scheduling (IRIS) Design Basis Document (DBD) and stakeholder alternative proposals. The Chair then called upon Dr. White (ISO-NE) to begin the joint ISOs' presentation. Dr. White presented an overview of today's meeting objectives:

(1) The three main areas of the ISOs' presentation today are as follows:
   (a) External Interface: Congestion/FTRs
   (b) Cross-Border Fee Impacts
   (c) Capacity Import Issues

(2) The meeting will then move on to questions and answers on the ISO proposals and a review of the proposed IRIS Design Basis Document.

Dr. White reviewed the purpose of the joint stakeholder process as discussed at previous meetings:

(1) To discuss the white paper's options, the pros and cons of the two options, how they work, the rationale for each option, and the likely impact on the markets of each option.

(2) To gather stakeholder input on the merits of each option and to hear and respond to concerns and questions on each option.

(3) To forge a joint stakeholder consensus on a design option the ISOs can implement.

After the presentation, the following points were raised:

(1) A meeting participant asked what the process would be to get alternative options into a Design Basis Document format. He also asked for a description of the stakeholder process for the IRIS Design Basis Document.
(The Chair replied that if there is an alternative option to be proposed, please provide it to myself and/or the Chair of the NYISO Market Issues Working Group for discussion at the next joint stakeholder meeting. An alternative option (e.g., Option C) would be placed in a DBD format prior to review of the final DBD which would include any alternative options. For NEPOOL Market Participants, NEPOOL Counel has agreed to work with those proposing alternatives on DBD language. Minor revisions should be worked out with the ISOs in advance and, if necessary, offered as amendments to the DBD rather than as a complete stand-alone option as described above.)

(2) A meeting participant asked if doing nothing (i.e., neither of the two ISO options) was an option.
(The Chair stated that we can structure a straw vote, when we get to that point, so that remaining with the status quo would be an option if the meeting participants so desire.)

(3) A meeting participant expressed its support for this effort, cited the External Market Monitor's findings, and said from his perspective remaining with the status quo is not an option.

(The Chair replied we will have time to debate this topic at a later date when we structure and take the straw votes on the DBD.)

(4) A meeting participant said he had provided comments on what has been presented so far and included an alternative proposal with those comments. Should we provide a presentation of that alternative for the next joint stakeholder meeting?
(The Chair answered yes.)

Agenda Item #2: **DA CONGESTION AT EXTERNAL INTERFRACE AND TCC/FTRs**

Dr. White presented the DA Congestion at External Interface and TCC/FTRs topic to the joint stakeholder meeting attendees:

(1) Reviewed the six key elements of the ISOs' proposal (slide 6 of the presentation).
  (a) The overall design objectives are: (i) to equalize LMPs at the proxy nodes representing the interface at time the schedule is set; and (ii) to update the real-time schedule as frequently as technically feasible.
  (b) The ISOs have identified two market-based design options to achieve the design objectives (Tie Optimization (TO) and Coordinated Transaction Scheduling (CTS)).

(2) Currently, the New York and New England Day-Ahead Energy Markets clear separately and Day-Ahead Energy Market offers are submitted separately to each ISO's market.

(3) Under both IRIS options proposed by the ISOs each Day-Ahead Energy Market (NYISO and ISO-NE) would establish a congestion price at the external interface (a component of the LMP):
  (a) This is a change from how ISO-NE does this today and is similar to what NYISO does today.
  (b) This would be done separately for each market (New England and New York).
  (c) The Day-Ahead congestion price would be set using the same process under either IRIS option.
  (d) Each ISO's Day-Ahead congestion revenue would continue to flow to holders of its FTRs/TCCs between the external interface and internal locations.

At this point in the presentation, a meeting participant asked if there are currently FTRs between internal locations in New England and the External Nodes. Dr. White answered yes, but they are of limited value today because the External Nodes are modeled without congestion at the interface. Dr. White resumed his presentation:

(1) The examples in the presentation show how clearing with Day-Ahead congestion would work under IRIS (using either of the two design options).
  (a) The proposed process differs significantly from how the Day-Ahead Energy Market clearing works today in New England.
  (b) The proposed process is similar to how it works today in New York.
  (c) These examples assume no losses and no internal congestion (for simplicity).

Dr. White then reviewed the examples from the presentation on slides 13 through 20. Among the points noted were:

(1) Congestion revenue is collected where the internal price is higher than the import.

(2) The relevant part of the supply curve is at the margin.

(3) The examples for Participant G show charges, credits and net positions. These examples show the external interface being treated as much as possible like internal congested interfaces in the Day-Ahead Energy Markets, which are financial.

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

(1) A meeting participant asked, in reference to an example for Participant G, why Participant G would offer as it did if it is not able to capture the $4 differential between LMPs.
(ISOs: Dr. White answered we will be getting to that point later in the presentation on FTR/TCCs. Also, there may be reasons unrelated to the Day-Ahead Energy Markets such as Renewable Energy Certificates or impacts in other markets.)

(2) A meeting participant asked why we did not just use each ISO's internal price in clearing and settling these markets.
(ISOs: Dr. White replied that suggested process would not reflect the fact that the interface is congested and prevents clearing of otherwise in-merit resources. For example, NYISO may still have less expensive resources available but the interface is congested at 900 MW.)
The meeting participant said he did not understand why it is not $49 in New York and $54 in ISO-NE rather than $52 in both control areas.
(ISOs: Dr. White replied if we priced the External Nodes based on your values, we would not be paying the congestion cost. The ISOs' proposal implicitly divides the $4 congestion cost at the interface on the basis (in this case) of $3 attributed to NYISO and $1 attributed to ISO-NE.)

(3) A meeting participant said that this money goes to transmission owners to offset costs incurred. We have to have a single price to respect the Available Transfer Capability and hold the marginal resource(s) harmless so resources are not frequently failing to be scheduled at prices at or below their offers.

(4) A meeting participant asked how congestion is handled at the External Nodes now in ISO-NE.
(ISOs: Dr. White: It is complicated. At a high level, ISO-NE does not determine a congestion price and, instead, assigns a congestion price of zero at the External Nodes. This results in the Day-Ahead Energy Market clearing transactions that economically ought not to clear and creates uplift that would not occur at a price that included congestion.)
The meeting participant stated so we have FTRs but the congestion cost at the External Node is always zero.
(ISOs: Dr. White answered yes.)

(5) A meeting participant said the ISO-NE process sounded like there are no proxy bus prices at the border.
(ISOs: Dr. White answered no. ISO-NE has external node proxy bus prices but we do not include a congestion component in them.)
The meeting participant asked why the ISO-NE proxy bus price would ever differ from the internal price.
(ISOs: Dr. White replied generally, they are not likely to, except for losses.)

(6) A meeting participant noted that in the example being discussed it was said that the $52 price across the border could have been different. Why is that?
(ISOs: Dr. White replied that the congestion price is not determined entirely by Total Transfer Capability but, at least in part, by the offers that set the two prices at the proxy bus. The difference between the internal and external proxy bus price is by definition the congestion component at the border, and Market Participants could submit different prices to the different Day-Ahead Energy Markets.)

(7) A meeting participant asked if New England made a change in its tariff a few years ago to estimate congestion at the External Nodes rather than make it zero.
(ISOs: Dr. White answered yes, but not to calculate a congestion price. The change was for the purpose of reallocating the uplift created by not calculating the congestion price.)

Dr. White presented a summary of Day-Ahead Energy Markets under the ISOs proposal:

(1) Parties that wish to schedule Day-Ahead External Transactions would do so just as they do today.
(2) Each Day-Ahead Energy Market (New York and New England) would establish a congestion component of the LMP at the external interface.
    (a) In general, Day-Ahead LMPs and the congestion charge at the external interface could be different in each ISO's Day-Ahead Energy Market.
    (b) Each ISO's Day-Ahead congestion revenue would flow to holders of its FTRs/TCCs between the external interface and internal locations.

The presentation continued with a discussion of the distribution of Congestion Revenues from the Day-Ahead Energy Market congestion pricing:

(1) Separate TCC or FTR Holders in the two markets would be paid or would pay the difference between the LMP congestion components in the respective Day-Ahead Energy Markets.
(2) There is no common Congestion Revenue Fund under either IRIS option.

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

(1) A meeting participant asked why we were discussing the Day-Ahead Energy Markets when we have a Real-Time Energy Market design proposal.
(ISOs: Dr. White replied as noted on slide 6, implementing IRIS does involve making a few modest changes to the Day-Ahead Energy Markets to fix the congestion pricing at the interface.)
(2) A meeting participant asked if the Net Commitment Period Compensation (NCPC) netting for imports and exports that are scheduled simultaneously would now be deleted.
(ISOs: Dr. White stated that the special NCPC would be deleted and replaced with proper congestion pricing.)
A meeting participant asked how often the Roseton Tie is congested.
(ISOs: Dr. White replied real-time congestion occurs approximately 2.5% of the time (2% in one direction and 0.5% in the other direction).)
(3) A meeting participant asked is the congestion pricing worth the software programming and other implementation costs.
(ISOs: Dr. White stated that the 1385 line is congested a higher percentage of the time and would result in higher congestion costs. "In lieu of congestion" uplift in ISO-NE (at all interfaces) is currently in the range of millions of dollars.)
(4) A meeting participant asked, as a follow-up on a previous comment, what NYISO does to calculate Day-Ahead congestion prices at the interface today.
(ISOs: Dr. White replied the NYISO produces an approximation for the congestion pricing in the Day-Ahead Energy Market. Whether or not that is the efficient congestion price, we do

not know. New England decided not to pursue an approximation for the congestion pricing in the Day-Ahead Energy Market.)

The meeting participant asked wasn't there a project in New England on a separate track from this effort to develop congestion pricing.

(ISOs: Dr. White answered yes. The same person (Dr. White) at ISO-NE is in charge of both projects. With IRIS we can set congestion prices at the interface in a way that is economically correct, and no more or less complicated than how we price congestion internally within the control area. Without IRIS we would be calculating estimates and the accuracy of these estimates would be difficult to measure. We reached the conclusion that the IRIS effort can determine congestion pricing in the Day-Ahead Energy Market with more precision than the approximation effort that ISO-NE was pursuing on a separate track.)

(5) A meeting participant said that he heard the ISOs stating that they need IRIS in order to address congestion pricing to provide for FTRs to and from External Nodes in New England.

(ISOs: Dr. White replied it is not to create FTRs because we have FTRs to and from External Nodes in New England. It is the lack of Day-Ahead congestion pricing at the External Nodes that is an issue in New England.)

The meeting participant asked why is it that New York can accomplish Day-Ahead congestion pricing and New England cannot.

(ISOs: Dr. White answered that both ISOs are incapable of determining Day-Ahead congestion pricing accurately, however, the NYISO makes an approximation while ISO-NE and most other ISOs just ignore congestion at the border or set it to zero. Whether the approximation is correct or not is unknowable without an IRIS or similar system to compare it to.)

(6) A meeting participant asked why ISO-NE could not simply fix the current uplift calculation to reflect better information rather than include congestion in the Day-Ahead Energy Market pricing.

(ISOs: Dr. White answered we tried something similar that gave rise to concerns. More broadly, that approach does not address the problem of not setting the proper price signals.)

Agenda Item #3: **RT CONGESTION PRICING AT EXTERNAL INTERFACE**

Dr. White presented the RT Congestion Pricing at External Interface topic to the joint stakeholder meeting attendees:

(1) Most of the congestion revenue accrues in the Day-Ahead Energy Markets.
(2) Real-Time congestion residuals (revenue) are relatively small.
(3) Setting correct Real-Time congestion prices matters because they:
  (a) Affect Day-Ahead Energy Market offers and bids, bidding behavior, and prices.
  (b) Signal the marginal value of transmission capacity in Real-Time.
  (c) Affect Real-Time settlements in specific situations (e.g., where Real-Time transmission constraints bind and the Market Participant's Day-Ahead cleared MW do not equal its Real-Time cleared MW).
(4) The Problem Today
  (a) At External Interfaces:
    (i) Neither ISO has the information necessary to determine economically efficient Real-Time congestion prices at the interface.
    (ii) ISO-NE uses no external congestion component at all.
    (iii) NYISO uses an approximation of the external congestion component.

(b) Why don't we have the information? Setting economically efficient Real-Time congestion prices requires:
   (i) Real-Time marginal resource(s) on each side of the interface to be seen by both markets in Real-Time.
   (ii) Coordinated clearing and dispatch that identifies the 'shadow cost' of binding transmission constraint(s) at an external interface and dispatches resources accordingly.
   (iii) The Real-Time commitment and dispatch decision needs to be made simultaneously and jointly to avoid making an assumption about the external transaction price and its congestion component. Having assumed congestion in the LMPs is a problem because the difference between the LMPs is the congestion price. If each ISO clears transactions separately like today, their LMPs will change based on which transactions clear and the correct congestion price would typically turn out to be different from what was assumed. That matters because it means we would not clear the right resources at the margin.
   (iv) To achieve the right congestion prices we have to see and set the marginal resources on both sides of the interface at the time we set the congestion price.

At this point in the presentation, a meeting participant asked if clearing the right resources at the margin would have to reflect the fact that the NYISO is located between PJM and New England. Mr. Pike replied that one of the processes is to try to do this in NYISO with a three hour look-ahead and make scheduling adjustments as we move forward in time and iterate the process to improve the solution as conditions, prices, and schedules change. Mr. Pike stated that we are looking at adopting this forward looking process both between New York and New England and between New York and PJM.

Dr. White resumed the presentation by summarizing the IRIS solutions:

(1) The basic economic principle of both IRIS options is that the total Real-Time congestion price across any constrained interface should equal the difference between the Real-Time LMPs of the marginal resources on each side of the transmission constraint.
   (a) Why? That is marginal value of transmission capacity in reducing total system production costs.
(2) Tie Optimization can set economically-correct Real-Time congestion charges across the New York/New England interfaces because it is done as part of the security constrained economic dispatch based on offers and demand in both ISOs.
(3) Coordinated Transaction Scheduling can set "approximately correct" Real-Time congestion charges because it has the same information. The approximation becomes "correct" if all cleared interface bids are zero. The approximation will be incorrect to the degree that a risk premium is charged on interface bids, or other bidding behavior creates deviations from an economically efficient dispatch solution.

A meeting participant asked if the presentation's comparison of CTS and TO included consideration of the risk of uplift. Dr. White answered yes; we are proposing to eliminate uplift and other fees from External Transactions under either proposal. Dr. White resumed his presentation:

(1) The ISOs see an issue in how each ISO should set the congestion component of its Real-Time LMP at the applicable External Node(s) in order for the following to occur:
   (a) No double-counting issues arise. If the total difference between LMPs is $10, each ISO cannot charge $10 because that would recover the congestion costs at the border twice.
   (b) The total (sum of ISOs) congestion charges equal the economically correct total congestion cost ($10 in the example) across the interface.

(2) From an ISO perspective, the simplest option is to have each ISO set the congestion component of its LMP at one-half of the total Real-Time congestion cost across the interface. Why propose this approach?
   (a) This is a simple, transparent, and (under Tie Optimization) an efficient solution.
   (b) This approach gets the total congestion charge economically correct.
   (c) There are countless ways to divide this congestion charge between the two markets but having a simple, transparent, and efficient methodology is important and all three of those factors may well change as the allocation becomes more complex and costly.

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

(1) A meeting participant asked why calculating the real congestion but dividing it 50/50 is any better than just utilizing estimated congestion and dividing it on a better method.
(ISOs: Dr. White replied we can determine the total congestion cost across the interface. We can determine the internal cost. What economics cannot determine is who should charge for the congestion (which ISO) because it is at the border.)

(2) A meeting participant asked for an explanation of how this congestion is different from internal congestion.
(ISOs: Dr. White replied let's look at the example where the difference between marginal units on opposite sides of a constraint is $10. The correct congestion charge is $10. Inside an ISO the charge across such an interface is $10. Externally, which ISO should administratively impose the $10 charge? This is not a question we face internally because the ISO imposes the congestion charge unilaterally and charges it out under its tariff's allocation scheme.)

(3) A meeting participant said we should look at what was done in the Day-Ahead Energy Market example where the congestion cost was implicitly shared under separate Day-Ahead Energy Markets.
(ISOs: Dr. White stated if schedules were not coordinated in Real-Time it would be the same as the Day-Ahead Energy Market example and Market Participants would pay both ISOs for congestion. Because we are coordinating these schedules, we need some mechanism for sharing the resulting congestion cost between the ISOs.)

(4) A meeting participant asked for confirmation that the congestion funds are placed into a common congestion fund to pay TTCs and FTRs.
(ISOs: Dr. White answered no. This is Real-Time congestion so there is no direct impact on TTCs and FTRs. There is no common congestion fund. Each ISO's share of Real-Time congestion flows through its own tariff provision for allocation.)

The presentation continued with a discussion of numerical examples for Real-Time congestion:

(1) On slide 45 (in Example 1) it was pointed out that there were no deviations and so Real-Time Settlements were all zero. It would be unusual for this to be the case. Market Partcipants

using virtual transactions may be more concerned about Real-Time congestion than Market Participants generally because they are deliberately taking different positions in the Day-Ahead and Real-Time Energy Markets.

(2) On slide 50 (in Example 2) the Real-Time Total Transfer Capability (TTC) differs from what it was Day-Ahead and is binding. In the example the Real-Time TTC decreased from the 900 MW DA TTC to 500 MW after the Day-Ahead Energy Market cleared:
   (a) NY LBMP goes to $48.75 and the New England LMP goes to $56. The economically correct congestion price is therefore $7.25 ($56 - $48.75).
   (b) If this had occurred inside New England, the congestion price would be $7.25. If this had occurred inside New York, the congestion price would be $7.25.
   (c) Who charges the $7.25?
      (i) Using the ISOs' proposed 50/50 split makes each ISO's congestion price $3.625 at the border, so that the LMP at the border is $52.375 ($56 - $3.625 and $48.75 + $3.625).

(3) Real-Time congestion prices under the Tie Optimization option:
   (a) The methodology is simple and transparent relative to today's approach**.** Under today's approach, NE congestion prices are not set according to a pricing algorithm, but billed through uplift under a complex allocation scheme.
   (b) Real-Time congestion revenue is not a common occurrence.
   (c) This method achieves the correct total Real-Time congestion cost.
   (d) This method allocates Real-Time congestion accruals (if any) so as to preclude double recovery and in a simple transparent manner. As proposed, this method allocates Real-Time congestion accruals in equal measure to each ISO.

(4) Who pays/receives Real-Time congestion within each ISO?
   (a) The ISOs are proposing no change to 'within ISO' allocations. Each ISO's existing (and different) rules for allocating Real-Time congestion accruals to Market Participants can stay the same. Both markets currently have extensive and complicated tariff provisions for these allocations and harmonizing those rules would be a major project in itself.

At this point in the presentation, a meeting participant asked about the treatment of new interties. He stated that in the past there has been debate over whether to use physical or financial rights for new Market Participant funded facilities. The meeting participant asked under these proposals do the financial rights end up superior to or equal to the physical rights much as is the case for internal interfaces where the ISO optimizes flows. He encouraged the ISOs to consider ways for incremental revenues to be allocated to new interties that add capability.

The presentation continued with a review of Cordinated Transaction Scheduling (see examples on slides 57-58 of clearing with interface bids). Under CTS, the Real-Time congestion prices must change to account for the interface bids even where nothing else changes (i.e., there is no deviation from Day-Ahead quantities). These changes will affect Day-Ahead cleared resources that do not also have cleared interface bids. At this point in the presentation, the following points were raised:

(1) A meeting participant asked how soon before an interval could Market Participants provide interface bids.
(ISOs: Mr. Pike replied offer and bid submissions will follow the current rule (i.e., 75 minutes before the hour). We need lead time to manage our other interfaces and "fast-start" turbines

so we have to get the bid data in advance. We will update the schedules as we get closer to the hour.)
The meeting participant asked would you be committing resources during this period.
(ISOs: Mr. Pike replied that works into the existing Real-Time commitment process in NYISO's Real-Time commitment software.)
The meeting participant asked how would you account for Start-Up, Minimum Run Times, etc.
(ISOs: Mr. Pike answered in the same manner as today. The unit commitment decision is based on bid production cost minimization at all borders.)
The meeting participant asked does New England's Real-Time commitment process work the same way.
(ISOs: Dr. White answered no.)
The meeting participant asked will it work the same way with the IRIS implementation.
(ISOs: Dr. White answered no.)
The meeting participant asked doesn't that raise a cost question.
(ISOs: Dr. White answered no. ISO-NE does not have the same software or vendor as NYISO but does the same type of economic optimization logic performed on a somewhat different frequency.)

(2) A meeting participant asked whether ISO-NE might start a fast start resource under these options.
(ISOs: Dr. White replied if it were economic to do so under our dispatch methodology, yes.)
The meeting participant asked do the total costs of starting such a unit need to be reflected in that decision.
(ISOs: Dr. White answered yes. We will look into the potential impact, if any, of these two options on starting of fast start resources under ISO-NE's co-optimized Energy and Operating Reserves economic dispatch and how such resources would be compensated.)

Numerical examples were presented of the CTS option using hypothetical Participant G:

(1) To avoid balancing charges in Real-Time Participant G has to clear an interface bid.
(2) If Participant G did not bid or did not clear an interface bid in the example presented it creates a Real-Time deviation of 100 MW at a net charge of $200 (based on the $2 congestion charge).

Dr. White summarized CTS by listing the ISOs' key observations:

(1) Real-Time congestion prices with interface bids are neither simple, nor transparent.
(2) CTS Real-Time congestion prices do not reflect the "true" economic cost of congestion at the external interface.
(3) Congestion prices are distorted by using interface bids.
(4) If the Day-Ahead Energy Markets accurately predict Real-Time prices (on average), then TCC/FTR holders will tend to receive less congestion revenue under CTS than under TO. The expected profit of interface bids tends to reduce congestion revenue distributions.

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

(1) A meeting participant asked, since this is a question of how to divide congestion costs, whether this is a function of limiting our thinking to two parties. What if there was an entity between the two parties?
(ISOs: Dr. White requested clarification of the question.)
The meeting participant said that it continues to bother him that a Market Participant cannot buy at $49 and sell at $53 in the example presented. If there were a separate settlement mechanism outside the ISOs would that be different? Are our structural constraints limiting our thinking on this topic?
(ISOs: Dr. White replied that you could think of the holders of TCCs or FTRs as that third party with the ISO acting as a settlement agent.)
The meeting participant stated a Market Participant can get an FTR up to $53 in either ISO but cannot buy an FTR for the difference.
(ISOs: Mr. Pike replied that you would need to buy the two halves separately.)

(2) A meeting participant said that the transmission lines on both sides would have to compete for what is being suggested to work because competition among marketers would not address the transfer limitation.

(3) A meeting participant asked whether we would have lower congestion under CTS or just less congestion revenue with the risk of underfunding FTRs.
(ISOs: Dr. White answered under either IRIS option the difference between the LMPs is the true cost of Real-Time congestion (i.e., $4 in the example). What turns up in the Congestion Revenue Fund in each ISO is different under CTS because $2 is paid to cleared interface bids leaving $2 in the Congestion Revenue Fund. The impact on FTRs and TTCs is indirect because we are dealing with Real-Time congestion revenue and its impact on Day-Ahead Energy Market behavior. There is no underfunding concern, because the TTC/FTR holders get whatever the congestion revenue turns out to be either way ($2 under CTS or $4 under the TO option).)

(4) A meeting participant said that under either IRIS option the true congestion cost is $4 and under the TO option it is allocated as $2 to each market while under the CTS option $2 goes to the interface bidders. Is that the problem?
(ISOs: Dr. White answered it is not a problem per se just a change in the cash flow that is positive for some parties and negative for other parties.)

(5) A meeting participant asked what is the better price signal from an efficiency perspective, interface bids or LMPs.
(ISOs: Dr. White replied Market Participants should be able to see the true cost of congestion (i.e., $4) in prices, and that is an important price signal. Under interface bidding, we would need to add back the interface bid to each ISO's congestion price to get the proper price signal. Interface bids alone do not reveal the marginal cost of transmission. This is less transparent than the TO approach, but Market Participants could add these together.)
The meeting participant stated that the data is all there, but getting the price signal under the CTS option is just more (and perhaps needlessly more) complicated.

(6) A meeting participant said that the added efficiency in the TO option comes from the ISOs' use of market sensitive information to make the proper decisions. Where is the efficiency gain in this option? What information will be provided to Market Participants?
(ISOs: Dr. White answered at low or zero interface bids both IRIS options would provide the desired outcome. Today, we have power flowing in the wrong direction and correcting that phenomenon is a significant efficiency gain.)

The meeting participant asked where there are transactions in the wrong direction that Market Participants have entered; you would schedule transactions in the other direction to offset it.
(ISOs: Dr. White answered no. Under CTS, we expect there will be standing interface bids submitted an hour ahead that get cleared every 15 minutes.)

(7) A meeting participant said that if interface bids get too high they will interfere with efficiency, unlike the example presented which has interface bids at a value less than the true congestion cost of $4.

<u>Agenda Item #4:</u> **<u>UPLIFT AND TRANSACTION FEES AT EXTERNAL INTERFACE</u>**

Mr. Pike presented the Uplift and Transaction Fees at External Interface topic to the joint stakeholder meeting attendees:

(1) The ISOs' proposal is to eliminate fees allocated to External Transactions at the Roseton/Sandy Pond and 1385 nodes.
  (a) Reciprocal elimination of charges will lower barriers to economically efficient interchange.
  (b) The fee elimination would apply under both Tie Optimization and Coordinated Transaction Scheduling proposals.

(2) These fees fall into three general categories:
  (a) Cost of ISO operations fees.
  (b) Ancillary services.
  (c) Production cost guarantees (i.e., uplift).

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

(1) A meeting participant said that at some point he would need to hear the ISOs' thoughts about including Cross Sound Cable (CSC) in this proposal and what, if any, components of this proposal to eliminate fees allocated to External Transactions could be applied to the CSC External Node. The meeting participant stated that his client is not asking to have CSC included in this effort at this time; however, we would like to see if any components of this proposal could apply to the CSC External Node. This could perhaps include a change in the scheduling regime for CSC.

(2) A meeting participant asked if the Cross Sound Cable is a merchant facility.
The prior speaker asked why that would matter in this discussion.
The meeting participant noted there would be different investors, reservation requirements and other differences between CSC and the other NewYork and New England tielines to be dealt with.

The presentation resumed with a discussion of ISO-NE fees:

(1) There are four main elements of ISO fees:
  (a) Day-Ahead NCPC charges at the New York/New England interfaces (The Roseton & 1385 External Nodes). This currently includes 'in lieu of congestion' credits/debits at these nodes.
  (b) Real-Time NCPC charges at the New York/New England interfaces (Roseton & 1385 Exernal Nodes)
  (c) ISO Self-Funding Tariff Fees (Roseton & 1385 nodes)

(d) Two of the Ancillary Services Costs under the tariff (Roseton & 1385 nodes)
(2) Each of these fees/charges is allocated to (slightly) different 'pools' of Market Participants.
(3) If these fees were eliminated at the New York/New England proxy nodes, most affected fees and charges would fall to a remaining 'pool' of Market Participants under current cost allocation rules.

The allocations currently used by ISO-NE were summarized:

(1) Day-Ahead Economic NCPC is allocated to Day-Ahead Load Obligations. There is a relatively small amount of Day-Ahead Economic NCPC. Most Economic NCPC is incurred in Real-Time. The 2010 total pool-wide was less than \$5.7 million and at the NY/NE Tie (Roseton & 1385 nodes) it was less than \$200,000.
    (a) A meeting participant asked if these numbers were for all hours or just for hours where External Transactions were scheduled.
    (ISOs: Dr. White answered these are total cumulative dollars for all hours.)
    The meeting participant suggested future presentations use the hours where External Transactions were scheduled.
(2) Non-Economic Day-Ahead NCPC (this applies to External Nodes only) arises from the way the External Transactions clear in the absence of a congestion component in ISO-NE's external nodal price.
    (a) Non-Economic Day-Ahead NCPC is charged and credited to External Transactions and Virtual Transactions at these External Nodes only, not to Market Participants generally.
    (b) Day-Ahead congestion pricing at the NY/NE External Nodes will replace this category of NCPC under either of the two IRIS options.
    (c) The 2010 Non-Economic Day-Ahead NCPC at all ISO-NE external nodes was approximately \$4.6 million while this NCPC category at the NY/NE interface (Roseton & 1385 nodes) was approximately \$3.5 million.
(3) Real-Time Economic NCPC
    (a) This type of NCPC arises because of unrecovered startup, no-load, and other (e.g., canceled start) costs of suppliers.
    (b) Real-Time Economic NCPC is presently allocated to total Real-Time deviations from Day-Ahead cleared MW positions (primarily to load; but also to Virtual Transactions, uninstructed generator deviations, etc.). The 2010 Real-Time Economic NCPC is approximately \$6.5 million at the New York/New England interface and \$74 million pool-wide. This type of NCPC is also volatile and difficult to predict.
        (i) At this point in the presentation, a meeting participant said that under the current rules if a Day-Ahead External Transaction failed to show up in Real-Time it would be assessed a charge under NCPC. Under this proposal, it would appear that the waiver would result in the External Transaction being exposed only to the difference between the Day-Ahead and Real-Time prices. Will this provide the correct incentive to match Day-Ahead and Real-Time schedules? Would this apply to any type of Day-Ahead transaction even if it were flowing in the "wrong" direction?
        (ISOs: Mr. Pike replied under Tie Optimization, we would dispatch generation in Real-Time so that this would not be needed (as there would be no Real-Time External Transactions as we currently know them). Under CTS the assumption is that someone would submit offsetting counterflows to transactions in the "wrong" direction in order to benefit from the price difference. In either case, we would want to eliminate these

charges so that we do not interfere with price convergence at the interface. Maintaining this fee in particular could be a problem given its volatility.)

(4) ISO Self-Funding Tariff Fees
   (a) These fees fund ISO operations. They are presently allocated (primarily) to load (under Schedule 1), exports (under Schedules 1 and 3), and energy market transactions (under Schedule 2). The 2010 total charges allocated to all Market Participants and nodes pool-wide was $146.5 million while charges allocated to External Transactions at the NY/NE Tie (Roseton & 1385 nodes) was $4.8 million (3.3% of the total).

(5) Ancillary Service Costs Allocated to External Transactions
   (a) Exports are allocated a portion of two pool-wide Ancillary Service costs; (i) Regulation service and (ii) VAR costs. The 2010 total charges allocated to all Market Participants and nodes pool-wide was $42.2 million while charges allocated to External Transactions at the NY/NE Tie (Roseton & 1385 nodes) was $1.4 million (3% of the total).

Mr. Pike presented a chart showing total fees (see slide 75) and noted that a total of approximately $13 million in fees to exports is currently being assessed. At this point in the presentation, the following points were raised:

(1) A meeting participant said he thought exports also paid Operating Reserves cost. (ISOs: Dr. White answered no. External Nodes are not in Reserve Zones and are therefore not charged.)
(2) A meeting participant asked what the estimated savings would result from implementing either of these two IRIS options.
   (ISOs: Mr. Pike replied short-term savings to loads of over $100 million were estimated by Potomac Economics.)
(3) A meeting participant asked why, on a cost causation basis, it would be right to move these fees elsewhere. We presumably had a reason to impose them originally.
   (ISOs: Mr. Pike replied that this question will be addressed in the presentation.)
(4) A meeting participant asked placing aside the congestion uplift, are you proposing to do away with these fees entirely or just charging them at the sink (like Through or Out Service Charges).
   (ISOs: Mr. Pike replied right now we are just quantifying them but we will propose to eliminate them.)

The presentation resumed with a discussion of the impact of eliminating Real-Time NCPC allocation to the NY/NE interface nodes in ISO-NE:

(1) In 2009 this would have caused a $0.068 increase per MWh of RT deviation.
(2) In 2010 this would have caused a $0.201 increase per MWh of RT deviation.
(3) Since most deviations under the two options would now be instructed deviations (i.e., deviations created by following the ISO's Dispatch Instructions in Real-Time) we might want to reconsider the allocation method.

A meeting participant asked where are the simultaneous import/export disallowances for gaming addressed in this fee elimination proposal. Dr. White replied if you are referring to the NCPC that applies only to External Nodes, which we've referred to as Non-Economic NCPC, that

NCPC fee will be replaced by the congestion pricing in LMPs so there is no such uplift and therefore no gaming opportunity.

The discussion turned to the NYISO Cross Border Fees, which were summarized as follows:

(1) Bid Production Cost Guarantees
 (a) Generators and importers are guaranteed to receive bid costs over the service day
 (b) In 2010 these payments were $1.2 million (Roseton/Sandy Pond & 1385 proxy nodes).
(2) Margin Assurance Payments
 (a) Protection to suppliers for ISO instructed Real-Time deviations from Day-Ahead position.
 (b) In 2010 these payments were $530,000 (Roseton/Sandy Pond & 1385 proxy nodes).
(3) Operating Reserves
 (a) An availability payment to suppliers to maintain capacity available for conversion to energy.
 (b) In 2010 these payments were $786,000 (Roseton/Sandy Pond & 1385 proxy nodes).
(4) Voltage Support (VSS)
 (a) An availability payment to suppliers to maintain capability to provide voltage support to the grid.
 (b) In 2010 these payments were $1.7 million (Roseton/Sandy Pond & 1385 proxy nodes).
(5) Non-ISO Facilities Charge
 (a) Operating costs for the Ramapo PAR and the Station 80 Capacitor Bank
 (b) In 2010 these payments were $77,000 (Roseton/Sandy Pond & 1385 proxy nodes).
(6) NYISO Cost of Operations:
 (a) These charges pay for the NYISO annual budget and FERC fees.
 (b) In 2010 these payments were $3.8 million (Roseton/Sandy Pond & 1385 proxy nodes).

The cost allocations associated with Cross Border fees were summarized as follows:

(1) Total affected fees and (net) charges on External Transactions were approximately:
 (a) New York: $8 million in 2009 and $8 million in 2010.
 (b) New England (excluding "in lieu of congestion" uplift): $8 million in 2009 and $12 million in 2010.
(2) Under current rules, this would instead be allocated to other Market Participants (in large part, but not entirely, to loads).
 (a) Reallocation would reduce the individual benefits of IRIS to some participants due to the reallocated costs.
 (b) Potomac Economics estimate of near-term annual benefit under IRIS is over $100 million for loads
(3) Why Eliminate Fees at the border?
 (a) This is a reciprocal elimination of roughly equivalent largely offsetting fee burdens on transfers of power across the tie:
  (i) Removal of these fees eliminates an impact on LBMPs;
  (ii) Fee elimination is a continuation of efforts originally pursued with the removal of transaction wheeling charges in 2004 (called Through or Out Service Charges in NEPOOL);
(4) Markets are more efficient when prices converge:

(a) The current fees result in a price spread between markets to cover the expected uplift allocations.
(b) Charging these fees results in the market operating to a higher total production cost and under-utilizes the transmission system.
(c) Eliminating these fees makes the most economically efficient use of facilities on both sides of the interface.
(d) Uplift allocations can be highly variable, resulting in significant trading risk and greater price divergences that are more likely to occur at times when significant interface scheduling is desired.

At this point in the presentation, a meeting participant commented that the costs incurred to secure the benefits of more efficient use of the tie should be reallocated to those who benefit from added imports and exports. These costs should not be allocated to those harmed by increased imports or exports.

<u>Agenda Item #5:</u> **<u>CAPACITY IMPORTS UNDER IRIS</u>**

Mr. Pike presented the Capacity Imports under IRIS topic to the joint stakeholder meeting attendees. IRIS fundamentally changes how energy transfers between the NY and NE areas are determined:

(1) The Real-Time External Transaction functionality in place today is eliminated under Tie Optimization and is replaced with an alternative economic construct under Coordinated Transaction Scheduling.
(2) This necessitates corresponding changes to the existing capacity import rules to complement TO and CTS.
(3) The goal of any capacity-related changes is to maintain both ISO and Market Participant requirements for managing capacity imports.

<u>Role of External Transactions</u>

(1) ISOs Operational Requirements:
  (a) External Transactions are the mechanism that the ISOs use to access energy from external capacity sources.
(2) Market Participant Capacity Requirements:
  (a) External transactions are the mechanism that Market Participants use to meet the requirements to offer and deliver energy from capacity imports. Those requirements vary by market.
  (b) The status of a Real-Time External Transaction is an input into capacity market penalty assessments.
(3) Today, during capacity deficient conditions each ISO can gain access to energy backed by import capacity through Real-Time External Transactions:
  (a) ISO-NE can request import transactions backed by Import Capacity Resources.
  (b) NYISO can request that Market Participants make capacity available and offer import transactions into the Real-Time Energy Market.
(4) Today, a Market Participant with an import capacity obligation must submit both Day-Ahead and Real-Time External Transactions into the 'sink' market and schedule energy when requested.

(a) In ISO-NE the obligation to offer applies to both Day-Ahead and Real-Time Energy Markets.
(b) In NYISO the obligation to offer applies to the Day-Ahead, and when requested for capacity deficiencies, in Real-Time.

Under IRIS

(1) The ISO must continue to have visibility of resources and the ability to dispatch resources for reliability in Real-Time.
(2) The Market Participant must continue to offer Day-Ahead External Transactions into the 'sink' market.
(3) The Market Participants' Real-Time obligations must be adjusted to coordinate with scheduling practices, under either IRIS option.
(4) The ISOs are evaluating potential requirement changes in order to meet the capacity market obligations. Details will be discussed in future stakeholder meetings.

The ISOs need to be able to see availability and system conditions. We do not foresee fundamental changes to this under either option. We recognize there is a lot of history on external capacity resources and welcome feedback. At this point in the presentation, the following points were raised:

(1) A meeting participant said there was a need for more discussion of how resources selling energy backed by capacity outside of New England but not selling capacity in New England will be dealt with. Also, the reserve adequacy decisions in both ISOs need further discussion because energy transactions from capacity units will impact the Reserve Adequacy Analysis process.
(ISOs: Mr. Pike replied that we need to discuss what obligations Market Participants are taking on in varied conditions in subsequent discussions.)
The meeting participant agreed and said he would like to get that done before voting on an IRIS Design Basis Document.
(2) A meeting participant asked how will TO work in terms of a specific unit's deliverability.
(ISOs: Mr. Pike answered the specifics of this process will need to be developed and at this point we do not know if it will be a difficult or easier task under either of the IRIS options. The obligation to deliver capacity from a specific unit is generally not considered capacity backed if that resource is not running.)

Agenda Item #6: **QUESTIONS AND ANSWERS**

The Chair proceeded to open the floor for any questions on the subjects discussed at today's meeting. The following question was asked:

(1) A meeting participant asked have the ISOs considered separating the charges to recover costs of providing services and facilitating transactions from the more volatile charges.
(ISOs: Mr. Pike replied that at this point we have not tried to parse these charges out. Do they impact markets differently? Yes, because they are allocated differently. All charges have an impact on efficiency. We are open to feedback on what should or should not be included in the recommended reciprocal waivers or the prioritization of these charges.)

Agenda Item #7: **SUMMARY: DESIGN BASIS DOCUMENT/CONCEPT OF OPERATIONS**

Prior to beginning the discussion of this agenda item, the Chair reminded the meeting participants that those with alternative proposals should provide them for discussion at the March 28th joint stakeholder meeting. We need to receive requests for time on the March 28th meeting agenda by March 15th and presentation documents for posting by March 22nd. Major alternatives would be a stand-alone option (e.g., Option C) for purposes of the IRIS DBD. Those with less extensive changes and/or proposed amendments to either of the two IRIS options should speak with Mr. Pike or Dr. White. However, if they do not support a proposed amendment, a participant can still bring the proposed change to its respective stakeholder committee under the normal process of submitting an amendment to the base proposal. For NEPOOL Market Participants, NEPOOL Counsel is available to help with drafting of proposals. At this point, the following points were raised:

(1) A meeting participant asked if he could receive the draft IRIS Design Basis Document in Microsoft Word format so he could provide redline edits to the document.
(The Chair answered yes. We will have the Markets Committee Secretary make the Microsoft Word version available to all meeting participants.)
The meeting participant asked is a fully developed proposal expected at this time or just a higher level summary.
(The Chair replied for the next joint stakeholder meeting the more detail that is provided the better it will be for all parties' understanding. For the April 28th joint stakeholder meeting we would look for alternative proposals to be in the IRIS DBD format.)

(2) A meeting participant asked if the IRIS Design Basis Document being presented today is the final version.
(ISOs: Dr. White answered we expect the IRIS DBD to evolve. The wording was intentionally parsimonious. We are not opposed to adding more detail or clarifications where stakeholders think they are needed.)
The meeting participant noted that details we went through on unit commitment and the rights retained by resources on capacity do not seem to be reflected in the current draft IRIS DBD.

(3) A meeting participant asked if the CTS proposal currently has the 75 minute before the interval bid date.
(ISOs: Mr. Pike answered yes; both IRIS options have that requirement.)

(4) A meeting participant said his company could not complete the development of an alternative proposal on the timeline provided by the Chair.
(The Chair replied that we recognize that this timeline is tight.)
The meeting participant asked what is driving this compressed timeline. Why do we need to have the vote on the IRIS DBD in May?
(ISOs: Dr. White replied that we have been discussing this subject since December of last year.)
The meeting participant replied that is correct, however, the IRIS white paper became available in January of this year.
(ISOs: Dr. White stated we are trying to accomplish the market rules for this project in about a year. To that end, we split the process into two stages. If we want to get the market rules in a year we have about five months to get through five joint stakeholder meetings and achieve an advisory vote to select one of these two IRIS options or come up with another option. After

we have decided on the direction to take, we can start the detailed effort of developing tariff language, addressing the implementation effort, etc. We do not want to start the Market Rule 1 language discussions in New England until an IRIS option is chosen.)

(5) A meeting participant said that from a Market Participant perspective requiring them to put forward an alternative on this timeline is a little unfair. We would like to work with other stakeholders to develop an alternative option and need additional time.
(The Chair replied that the ISOs have been trying to indicate a timeframe with each presentation. We also need to be respectful of the efforts of stakeholders who have already indicated they will present alternatives. For now, if a meeting participant has something to propose, we will be looking for general terms of the proposal and a request for agenda time.)

(6) A meeting participant asked if anyone would be precluded from bringing an alternative proposal at the April 28th joint stakeholder meeting.
(The Chair answered no; however, please do not wait until the very end. Let's deal with these alternative proposal(s) as they are ready. It would be very helpful to have both the proposal and DBD language by April 28th but we certanly will entertain a proposal that does not yet have DBD language.)

(7) A meeting participant said he needed answers to the questions he sent to the ISOs in order to prepare his alternative proposal.
(The Chair replied that is a fair request and the ISOs have heard your request.)

Dr. White presented an outline of the IRIS Design Basis Document to the joint stakeholder meeting attendees:

(1) This document is not intended to put forward anything new, but to capture the presentations and white paper.
(2) Even though the focus is on Real-Time, the interplay of the Day-Ahead and Real-Time Energy Markets is important.
(3) The IRIS DBD uses a parallel structure to discuss each option.
(4) The IRIS DBD is arranged in five sections each of which was described by Dr. White.
(5) Section 5 (Other Conceptual Design Elements) of the IRIS DBD does not really deal with market design but covers some other practices of interest.

Agenda Item #8: **MEETING SUMMARY AND NEXT STEPS**

Dr. White summarized the points made during today's presentation:

(1) Real-Time Scheduling Under IRIS
    (a) Both TO and CTS use market-based offers and bids to:
        (i) Increase generation in the lower-cost region in Real-Time, and
        (ii) Decrease generation in the higher-cost region in Real-Time.
        (iii) TO does more of the above two items, CTS does less of the above two items.
    (b) Both IRIS options set Real-Time flows in the economically-efficient direction.
    (c) The two ISOs have the information needed to optimize physical power flows in Real-Time**.**
    (d) Traders cannot see the bid stacks and transmission system status in Real-Time.
(2) Congestion and TCCs/FTRs
    (a) Each ISO (separately) issues TCC/FTRs for paths in its area, including the External Interface, as they do today;

(b) Each ISO will continue to pay TCC/FTR holders the Day-Ahead congestion revenue based upon Day-Ahead clearing prices;
(c) ISO New England will enable congestion pricing to occur at the interface under IRIS. This is not allowed today.
(d) Real-Time congestion revenue at the external ties accrues in equal measure in each ISO and flows through according to the existing tariff provisions in each ISO.

(3) Cross-Border Fee Elimination
(a) Reciprocal elimination of fees and charges at the external interface will lower barriers to economically efficient interchange.
(b) Markets are more efficient when prices converge.
(c) The proposed fee elimination applies to both the TO and CTS proposals.

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

(1) A meeting participant questioned the ISOs' statement that "TO does more…, CTS does less..." That is a fairly definitive statement. Aren't these options based on forecasts? What if something happens in Real-Time and the Market Participants more correctly anticipate the actual result? Would the ISO statement still be true?
(ISOs: Mr. Pike replied that the ISOs have all the information (including all the Supply Offers, Transmission limits, and Demand Bids) as well as the forecast and actual system conditions. TO would fully use this data while CTS would stop a little short of that and not bring on the least expensive resources. If there is a bias in forecasts the problem is much bigger than these tie lines because thousands of MW of economic generation and load would not be dispatched correctly under the general economic dispatch methodology. It should also be noted that these forecasts and economic dispatch results are reviewed and overseen by the External Market Monitor on a regular basis to, among other items, squeeze out any optimization bias.)

(2) A meeting participant said that the sooner we get TO in place the better. He said he did not understand why we are not just moving forward with TO. If there is some benefit to going to the CTS option, he would like to understand what that benefit is.

(3) A meeting participant said that any alternative proposals should include an explanation of how the alternative gets to a more efficient solution than the TO option.

Dr. White outlined the schedule and objectives for the next set of joint stakeholder meetings:

(1) Objectives:
(a) To understand the proposed IRIS options in detail, gather feedback, and refine the IRIS options into a preferred IRIS Design Basis Document by April or May.
(b) The ISOs will need a common IRIS DBD due to the coordination issues raised.

(2) The next joint stakeholder meetings are scheduled for March 28th (NYISO hosting) and April 28th (NYISO hosting)

(3) The current target is a December 2011 FERC filing of Market Rules for spring 2013 implementation.

NEXT MEETING

The next meeting of the Joint NEPOOL Markets Committee/NYISO Market Issues Working Group is scheduled to be held on March 28, 2011 in Albany, NY.

Respectfully submitted,

_______/s/_____________

Alex W. Kuznecow
Secretary
Markets Committee